GENESIS ENERGY LP
Form 10-Q
November 09, 2009

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

Form 10-Q

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

For the quarterly period ended September 30, 2009

OR

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

Commission file number 1-12295

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

Delaware (State or other jurisdictions 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 T No £

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

Yes o No £

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

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

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

Yes £ No T

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 November 9, 2009: 39,482,971

GENESIS ENERGY, L.P.

Form 10-Q

INDEX

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

Index

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

	September 30, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8,700	$ 18,985
Accounts receivable - trade, net of allowance for doubtful accounts of $1,915 and $1,132 at September 30, 2009 and December 31, 2008, respectively	126,533	112,229
Accounts receivable - related party	2,330	2,875
Inventories	38,825	21,544
Net investment in direct financing leases, net of unearned income -current portion - related party	4,088	3,758
Other	9,096	8,736
Total current assets	189,572	168,127
FIXED ASSETS, at cost	370,607	349,212
Less: Accumulated depreciation	(83,857)	(67,107)
Net fixed assets	286,750	282,105
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	174,108	177,203
CO2 ASSETS, net of accumulated amortization	21,169	24,379
EQUITY INVESTEES AND OTHER INVESTMENTS	20,129	19,468
INTANGIBLE ASSETS, net of accumulated amortization	144,659	166,933
GOODWILL	325,046	325,046
OTHER ASSETS, net of accumulated amortization	6,836	15,413
TOTAL ASSETS	$ 1,168,269	$ 1,178,674
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 97,186	$ 96,454
Accounts payable - related party	3,499	3,105
Accrued liabilities	28,568	26,713
Total current liabilities	129,253	126,272
LONG-TERM DEBT	384,400	375,300
DEFERRED TAX LIABILITIES	16,707	16,806
OTHER LONG-TERM LIABILITIES	3,079	2,834
COMMITMENTS AND CONTINGENCIES (Note 17)		
PARTNERS' CAPITAL:		
Common unitholders, 39,483 and 39,457 units issued and outstanding, at September 30, 2009 and December 31, 2008, respectively	595,698	616,971
General partner	16,205	16,649

Accumulated other comprehensive loss	(908)	(962)
Total Genesis Energy, L.P. partners' capital	610,995	632,658
Noncontrolling interests	23,835	24,804
Total partners' capital	634,830	657,462
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,168,269	$ 1,178,674

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

Index

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
REVENUES:				
Supply and logistics:				
Unrelated parties	$355,604	$554,838	$833,658	$1,552,559
Related parties	846	1,558	3,218	3,432
Refinery services	30,006	61,306	112,894	160,945
Pipeline transportation, including natural gas sales:				
Transportation services - unrelated parties	4,009	5,062	11,442	16,139
Transportation services - related parties	7,977	8,205	24,175	13,372
Natural gas sales revenues	435	1,158	1,667	4,085
CO2 marketing:				
Unrelated parties	3,712	4,039	9,821	10,895
Related parties	800	753	2,211	2,217
Total revenues	403,389	636,919	999,086	1,763,644
COSTS AND EXPENSES:				
Supply and logistics costs:				
Product costs - unrelated parties	324,162	521,779	751,524	1,471,254
Product costs - related parties	-	-	1,754	-
Operating costs	22,894	20,927	60,766	55,294
Refinery services operating costs	17,160	48,265	73,711	116,700
Pipeline transportation costs:				
Pipeline transportation operating costs	2,852	2,647	7,984	7,493
Natural gas purchases	395	1,136	1,519	3,990
CO2 marketing costs:				
Transportation costs - related party	1,603	1,488	4,251	4,121
Other costs	16	15	47	45
General and administrative	10,128	9,239	27,188	26,929
Depreciation and amortization	15,806	18,100	47,358	51,610
Net loss (gain) on disposal of surplus assets	17	(58)	(141)	36
Total costs and expenses	395,033	623,538	975,961	1,737,472
OPERATING INCOME	8,356	13,381	23,125	26,172
Equity in (losses) earnings of joint ventures	(788)	216	1,382	378
Interest income	18	118	55	352
Interest expense	(3,436)	(4,601)	(9,881)	(8,543)
Income before income taxes	4,150	9,114	14,681	18,359
Income tax (expense) benefit	(253)	1,504	(1,661)	1,233
NET INCOME	3,897	10,618	13,020	19,592
Noncontrolling interests	402	145	1,025	144
NET INCOME ATTRIBUTABLE TO				

GENESIS ENERGY, L.P.	$4,299	$10,763	$14,045	$19,736

Index

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:				
BASIC	$0.14	$0.25	$0.43	$0.45
DILUTED	$0.14	$0.25	$0.43	$0.45
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:				
BASIC	39,480	39,452	39,467	38,796
DILUTED	39,614	39,524	39,600	38,853

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$3,897	$10,618	$13,020	$19,592
Change in fair value of derivatives:				
Current period reclassification to earnings	224	(5)	514	(5)
Changes in derivative financial instruments - interest rate swaps	(315)	(211)	(400)	(211)
Comprehensive income	3,806	10,402	13,134	19,376
Comprehensive loss (income) attributable to noncontrolling interests	46	110	(60)	110
Comprehensive income attributable to Genesis Energy, L.P.	$3,852	$10,512	$13,074	$19,486

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

Index

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

		Partners' Capital				
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-Controlling Interests	Total Capital
Partners' capital, January 1, 2009	39,457	$ 616,971	$ 16,649	$ (962)	$ 24,804	$ 657,462
Comprehensive income:						
Net income	-	17,892	(3,847)	-	(1,025)	13,020
Interest rate swap losses reclassified to interest expense	-	-	-	251	263	514
Interest rate swap loss	-	-	-	(197)	(203)	(400)
Cash contributions	-	-	7	-	-	7
Cash distributions	-	(39,958)	(4,191)	-	(4)	(44,153)
Contribution for executive compensation (See Note 12)	-	-	7,587	-	-	7,587
Unit based compensation expense	26	793	-	-	-	793
Partners' capital, September 30, 2009	39,483	$ 595,698	$ 16,205	$ (908)	$ 23,835	$ 634,830

		Partners' Capital				
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-Controlling Interests	Total Capital
Partners' capital, January 1, 2008	38,253	$ 615,265	$ 16,539	$ -	$ 570	$ 632,374
Comprehensive income:						
Net income	-	17,972	1,764	-	(144)	19,592
Interest rate swap loss reclassified to interest expense	-	-	-	(2)	(3)	(5)
Interest rate swap loss	-	-	-	(104)	(107)	(211)
Cash contributions	-	-	510	-	25,505	26,015
Cash distributions	-	(34,805)	(2,017)	-	(4)	(36,826)
Issuance of units	2,037	41,667	-	-	-	41,667
Redemption of units	(838)	(16,667)	-	-	-	(16,667)
Partners' capital, September 30, 2008	39,452	$ 623,432	$ 16,796	$ (106)	$ 25,817	$ 665,939

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

-6-

Index

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$13,020	$19,592
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation and amortization	47,358	51,610
Amortization of credit facility issuance costs	1,448	962
Amortization of unearned income and initial direct costs on direct financing leases	(13,606)	(6,342)
Payments received under direct financing leases	16,390	6,056
Equity in earnings of investments in joint ventures	(1,382)	(378)
Distributions from joint ventures - return on investment	800	971
Non-cash effect of unit-based compensation plans	10,345	(1,342)
Deferred and other tax liabilities	1,084	(3,388)
Other non-cash items	(283)	(1,031)
Net changes in components of operating assets and liabilities (See Note 13)	(19,343)	(10,480)
Net cash provided by operating activities	55,831	56,230
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(28,656)	(29,890)
CO2 pipeline transactions and related costs	-	(228,891)
Distributions from joint ventures - return of investment	-	886
Investments in joint ventures and other investments	(83)	(2,210)
Acquisition of Grifco assets	-	(65,693)
Other, net	500	(213)
Net cash used in investing activities	(28,239)	(326,011)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings	174,300	490,900
Bank repayments	(165,200)	(179,500)
Credit facility issuance fees	-	(2,255)
Redemption of common units for cash	-	(16,667)
General partner contributions	7	510
Net noncontrolling interest (distributions) contributions	(4)	25,501
Distributions to common unitholders	(39,958)	(34,805)
Distributions to general partner interest	(4,191)	(2,017)
Other, net	(2,831)	(1,366)
Net cash (used in) provided by financing activities	(37,877)	280,301
Net (decrease) increase in cash and cash equivalents	(10,285)	10,520
Cash and cash equivalents at beginning of period	18,985	11,851
Cash and cash equivalents at end of period	$8,700	$22,371

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

Index

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

1. Organization and Basis of Presentation and Consolidation

Organization

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

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

Our 2% general partner interest is held by Genesis Energy, LLC, a Delaware limited liability company and an indirect subsidiary of Denbury Resources Inc. Denbury and its subsidiaries are hereafter referred to as Denbury. Our general partner and its affiliates also own 10.2% of our outstanding common units.

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

Basis of Presentation and Consolidation

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. The consolidated financial statements included herein have been prepared by us without audit pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, they reflect all adjustments (which consist solely of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of the financial results for interim periods. Certain information and notes normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. However, we believe that the disclosures are adequate to make the information presented not misleading when read in conjunction with the information contained in the periodic reports we file with the SEC pursuant to the Securities Exchange Act of 1934, including the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2008.

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

The accompanying unaudited consolidated financial statements and related notes present our consolidated financial position as of September 30, 2009 and December 31, 2008 and our results of operations and changes in comprehensive income for the three and nine months ended September 30, 2009 and 2008, and cash flows and changes in partners' capital for the nine months ended September 30, 2009 and 2008. Intercompany transactions have been eliminated. The accompanying unaudited consolidated financial statements include Genesis Energy, L.P. and its operating subsidiaries, Genesis Crude Oil, L.P. and Genesis NEJD Holdings, LLC, and their subsidiaries.

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

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

Index

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

Subsequent Events

We have considered subsequent events through November 9, 2009, the date of issuance, in preparing the consolidated financial statements and notes thereto.

2. Recent Accounting Developments

Pending

Measuring Liabilities and Fair Value

In August 2009, the FASB issued guidance that provides clarification to the valuation techniques required to measure the fair value of liabilities. The guidance also provides clarification around required inputs to the fair value measurement of a liability and definition of a Level 1 liability. The guidance is effective for interim and annual periods beginning after August 2009. We will adopt this standard beginning with our financial statements for the year ending December 31, 2009. We do not anticipate that our adoption of this standard will have a material effect on our financial statements.

Consolidation of Variable Interest Entities (“VIEs”)

In June 2009, the FASB issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Previously, variable interest holders had to determine whether they had a controlling interest in a VIE based on a quantitative analysis of the expected gains and/or losses of the entity. In contrast, the new guidance requires an enterprise with a variable interest in a VIE to qualitatively assess whether it has a controlling interest in the entity, and if so, whether it is the primary beneficiary. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation, rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company’s involvement with a VIE affects its financial statements and exposure to risks. This guidance is effective for us beginning January 1, 2010. We are currently assessing the impacts this guidance may have on our financial statements.

Implemented

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 168, “The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162,” (The Codification). The Codification establishes the FASB Accounting Standards Codification (ASC) as the source of authoritative U.S. generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. The Codification reorganizes GAAP pronouncements by topic and modifies the GAAP hierarchy to include only two levels: authoritative and non-authoritative. All of the content in the Codification carries the same level of authority. This statement was effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the Codification on September 30, 2009. Thus, subsequent references to GAAP in our consolidated financial statements will refer exclusively to the Codification.

Recognized and Non-Recognized Subsequent Events

In May 2009, the FASB issued new guidance for accounting for subsequent events. The new guidance, which is now part of Accounting Standards Codification (ASC) 855, "Subsequent Events", establishes the accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. See "Subsequent Events" included in "Note 1 – Organization and Basis of Presentation and Consolidation" for the related disclosure. The new guidance was applied prospectively beginning in the second quarter of 2009 and did not have a material impact on our consolidated financial statements.

Index

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

Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued new guidance regarding interim disclosures about the fair value of financial instruments. The new guidance, which is now part of ASC 825, "Financial Instruments", requires fair value disclosures on an interim basis for financial instruments that are not reflected in the consolidated balance sheets at fair value. Previously, the fair values of those financial instruments were only disclosed on an annual basis. We adopted the new guidance for our quarter ended June 30, 2009, and there was no material impact on our consolidated financial statements.

Business Combinations

In December 2007, the FASB issued revised guidance for the accounting of business combinations. The revised guidance, which is now part of ASC 805, "Business Combinations", retains the purchase method of accounting used in business combinations but replaces superseded guidance by establishing principles and requirements for the recognition and measurement of assets, liabilities and goodwill, including the requirement that most transaction costs and restructuring costs be charged to expense as incurred. In addition, the revised guidance requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The revised guidance will apply to acquisitions we make after December 31, 2008. The impact to us will be dependent on the nature of the business combination.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued guidance regarding noncontrolling interests in consolidated financial statements. The new guidance, which is now a part of ASC 810, "Consolidation", establishes accounting and reporting standards for noncontrolling interests, which were referred to as minority interests in prior literature. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent company. The new guidance requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e. elimination of the mezzanine "minority interest" category); (ii) elimination of minority interest expense as a line item on the statement of operations and, as a result, that net income be allocated between the parent and the noncontrolling interests on the face of the statement of operations; and (iii) enhanced disclosures regarding noncontrolling interests. The provisions of the new guidance were effective for fiscal years beginning after December 15, 2008. On January 1, 2009, we adopted the new guidance which changed the presentation of the interests in Genesis Crude Oil, L.P. held by our general partner and the interests in DG Marine held by our joint venture partner in our consolidated financial statements. Amounts for prior periods have been changed to be consistent with the presentation required by the new guidance.

Derivative Instruments and Hedging Activities

In March 2008, the FASB issued new guidance regarding disclosures about derivative instruments and hedging activities. The new guidance, which is now a part of ASC 815, "Derivatives and Hedging Activities", require enhanced disclosures about our derivative and hedging activities. This guidance was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the guidance on January 1, 2009 and have included the enhanced disclosures in Note 15.

Application of the Two-Class Method to Master Limited Partnerships

In March 2008, the FASB issued new guidance in ASC 260, "Earnings per Share", regarding the application of the two-class method to Master Limited Partnerships. Under this guidance, the computation of earnings per unit will be affected by the incentive distribution rights ("IDRs") we are contractually obligated to distribute at the end of the each reporting period. In periods when earnings are in excess of cash distributions, we will reduce net income or loss for the current reporting period (for purposes of calculating earnings or loss per unit only) by the amount of available cash that will be distributed to our limited partners and general partner for its general partner interest and incentive distribution rights for the reporting period, and the remainder will be allocated to the limited partner and general partner in accordance with their ownership interests. When cash distributions exceed current-period earnings, net income or loss (for purposes of calculating earnings or loss per unit only) will be reduced (or increased) by cash distributions, and the resulting excess of distributions over earnings will be allocated to the general partner and limited partner based on their respective sharing of losses. The new guidance was effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted ASC 260 on January 1, 2009 and have reflected the calculation of earnings per unit for the three and nine months ended September 30, 2009 and 2008 in accordance with its provisions. See Note 9.

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

Determination of the Useful Life of Intangible Assets

In April 2008, the FASB issued revised guidance, which is now a part of ASC 350, “Intangibles – Goodwill and Other”, regarding the determination of the useful life of intangible assets. The revised guidance amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset under superseded guidance. The purpose of the revised guidance is to develop consistency between the useful life assigned to intangible assets and the cash flows from those assets. The revised guidance was effective for fiscal years beginning after December 31, 2008. We adopted the provisions of the revised guidance on January 1, 2009, and adoption had no effect on our consolidated financial statements.

Fair Value Measurements

We adopted new guidance issued by the FASB regarding fair value measurements for our financial assets and financial liabilities on January 1, 2008, which is now a part of ASC 820, “Fair Value Measurements and Disclosures.” The adoption or financial assets and financial liabilities did not have a material impact on us. With regard to our non-recurring non-financial assets and non-financial liabilities, we adopted the provisions of this guidance effective January 1, 2009. This includes applying the provisions to (i) nonfinancial assets and liabilities initially measured at fair value in business combinations; (ii) reporting units or nonfinancial assets and liabilities measured at fair value in conjunction with goodwill impairment testing, (iii) other nonfinancial assets measured at fair value in conjunction with impairment assessments; and (iv) asset retirement obligations initially measured at fair value. The adoption for non-financial assets and liabilities does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements. The adoption of the guidance for non-financial assets and liabilities as described above had no material impact on us. See Note 16 for further information regarding fair-value measurements.

3. Consolidated Joint Venture – DG Marine

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

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 specified payments under our subordinated loan agreement and distributions in respect of our equity interest. At December 31, 2008, there were no amounts outstanding under the subordinated loan agreement. At September 30, 2009, $17 million was outstanding under the subordinated loan agreement; however this amount was eliminated in consolidation. In October 2009, we loaned an additional $8 million to DG Marine.

Index

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

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

	September 30, 2009	December 31, 2008
Cash	$ 1,308	$ 623
Accounts receivable - trade	3,176	2,812
Other current assets	2,432	859
Fixed assets, at cost	124,276	110,214
Accumulated depreciation	(7,492)	(3,084)
Intangible assets, net	1,871	2,208
Other assets	1,535	2,178
Total assets	$ 127,106	$ 115,810
Accounts payable	$ 1,448	$ 1,072
Accrued liabilities	10,853	9,258
Long-term debt	49,400	55,300
Other long-term liabilities	906	1,393
Total liabilities	$ 62,607	$ 67,023

4. Inventories

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

	September 30, 2009	December 31, 2008
Crude oil	16,358	1,878
Petroleum products	18,781	5,589
Caustic soda	993	7,139
NaHS	2,677	6,923
Other	16	15
Total inventories	$ 38,825	$ 21,544

5. Fixed Assets and Asset Retirement Obligations

Fixed assets consisted of the following:

	September 30, 2009	December 31, 2008
Land, buildings and improvements	$ 13,635	$ 13,549
Pipelines and related assets	153,379	139,184
Machinery and equipment	26,533	22,899
Transportation equipment	32,811	32,833
Barges and push boats	122,913	96,865

Office equipment, furniture and fixtures		4,295		4,401
Construction in progress		4,488		27,906
Other		12,553		11,575
Subtotal		370,607		349,212
Accumulated depreciation and impairment		(83,857)		(67,107)
Total	$	286,750	$	282,105

Depreciation expense was $6.3 million and $19.4 million for the three and nine months ended September 30, 2009, respectively. For the three and nine months ended September 30, 2008, depreciation expense was $6.5 million and $16.8 million, respectively.

Index

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

Asset Retirement Obligations

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

Asset retirement obligations as of December 31, 2008	$1,430
Liabilities incurred and assumed in the period	726
Liabilities settled in the period	(117)
Accretion expense	91
Asset retirement obligations as of September 30, 2009	2,130
Less current portion included in accrued liabilities	(150)
Long-term asset retirement obligations as of September 30, 2009	$1,980

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

6. Intangible Assets and Goodwill

Intangible Assets

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

		September 30, 2009			December 31, 2008		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Customer relationships:							
Refinery services	5	$ 94,654	$ 37,592	$ 57,062	$ 94,654	$ 26,017	$ 68,637
Supply and logistics	5	35,430	14,109	21,321	35,430	9,957	25,473
Supplier relationships -							
Refinery services	2	36,469	27,534	8,935	36,469	24,483	11,986
Licensing Agreements -							
Refinery services	6	38,678	10,555	28,123	38,678	7,176	31,502
Trade names -							
Supply and logistics	7	18,888	4,863	14,025	18,888	3,118	15,770

Favorable lease -							
Supply and logistics	15	13,260	1,026	12,234	13,260	671	12,589
Other	5	3,823	864	2,959	1,322	346	976
Total	5	$ 241,202	$ 96,543	$ 144,659	$ 238,701	$ 71,768	$ 166,933

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The favorable lease and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $8.3 million and $24.8 million for the three and nine months ended September 30, 2009, respectively. Amortization expense on intangible assets was $11.6 million and $34.8 million for the three and nine months ended September 30, 2008, respectively.

Index

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

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

Year Ended December 31	Amortization Expense to be Recorded
Remainder of 2009	$ 8,328
2010	$ 26,635
2011	$ 21,918
2012	$ 18,261
2013	$ 14,264
2014	$ 11,790

Goodwill

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

7. Equity Investees and Other Investments

T&P Syngas Supply Company

We are accounting for our 50% ownership in T&P Syngas under the equity method of accounting. We received distributions from T&P Syngas of $0.8 million and $1.7 million during the nine months ended September 30, 2009 and 2008, respectively. During the first quarter of 2009, "Equity in earnings of joint ventures" included $1.7 million of non-cash items related to T&P Syngas that increased earnings.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues	$ 1,217	$ 1,054	$ 3,368	$ 3,487
Operating expenses and depreciation	(2,809)	(392)	(3,907)	(1,124)
Other income (expense)	(12)	(11)	1	4
Net (loss) income	$ (1,604)	$ 651	$ (538)	$ 2,367

	September 30, 2009	December 31, 2008
Current assets	$ 3,016	$ 3,131
Non-current assets	17,728	18,906
Total assets	$ 20,744	$ 22,037
Current liabilities	$ 1,372	$ 543

Non-current liabilities		213		198
Partners' capital		19,159		21,296
Total liabilities and partners' capital	$	20,744	$	22,037

Index

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

8. Debt

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

	September 30, 2009	December 31, 2008
Genesis Credit Facility	$ 335,000	$ 320,000
DG Marine Credit Facility	49,400	55,300
Total Long-Term Debt	$ 384,400	$ 375,300

Genesis Credit Facility

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

As of September 30, 2009, our borrowing base was $419 million, and we had $335 million borrowed and $4.1 million in letters of credit outstanding. Thus, our total remaining availability at September 30, 2009 was $79.9 million under our credit facility. As discussed above, our borrowing base may be increased up to $500 million for material acquisitions and internal growth projects.

DG Marine Credit Facility

DG Marine has a $90 million revolving credit facility with a syndicate of banks led by SunTrust Bank and BMO Capital Markets Financing, Inc. That facility, which matures on July 18, 2011, is secured by all of the equity interests issued by DG Marine and substantially all of DG Marine’s assets. Other than the pledge of our equity interest in DG Marine, that facility is non-recourse to us. At September 30, 2009, our Unaudited Consolidated Balance Sheet included $127.1 million of DG Marine’s assets in our total assets.

At September 30, 2009, DG Marine had $49.4 million outstanding under its credit facility. As DG Marine has completed its capital expenditures for its fleet expansion, DG Marine reduced the maximum amount that may be borrowed under its facility to $54 million in November 2009.

In August 2008, DG Marine entered into a series of interest rate swap agreements to effectively fix the underlying LIBOR rate on $32.9 million of its borrowings under its credit facility through July 18, 2011. The fixed interest rates in the swap agreements range from the three-month interest rate of 3.60% in effect at September 30, 2009 to 4.68% at July 18, 2011.

Fair Value of our Debt

We have estimated the total fair value of our long-term debt under our credit agreement and the DG Marine credit facility to be approximately $371.4 million, or $13.0 million less than the carrying value of that debt. As a result of the current credit environment, we believe that the fair value of our debt does not approximate its carrying value as of September 30, 2009 because the applicable interest rate margin on our debt was below the market rates as of that date.

9. Partners' Capital and Distributions

Partners' Capital

Partner's capital at September 30, 2009 consists of 39,482,971 common units, including 4,028,096 units owned by our general partner and its affiliates, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving effect to the general partner interest), and a 2% general partner interest.

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

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

Without obtaining unitholder approval, we may issue an unlimited number of additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

Distributions

We will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves.

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

	Unitholders		General Partner	
Quarterly Cash Distribution per Common Unit:				
Up to and including $0.25 per Unit	98.00	%	2.00	%
First Target - $0.251 per Unit up to and including $0.28 per Unit	84.74	%	15.26	%
Second Target - $0.281 per Unit up to and including $0.33 per Unit	74.53	%	25.47	%
Over Second Target - Cash distributions greater than $.033 per Unit	49.02	%	50.98	%

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

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009 (1)	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931

(1) This distribution will be paid on November 13, 2009 to our general partner and unitholders of record as of November 2, 2009.

Index

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

Net Income Allocation to Partners

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

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

Net Income Per Common Unit

Our net income is first allocated to our general partner based on the amount of incentive distributions to be paid for the quarter. New accounting guidance issued by the FASB, effective January 1, 2009 for us, resulted in a change in the calculation of net income per common unit by changing the amount of the incentive distributions to be considered in the calculation from the distributions paid during the quarter to the distributions to be paid with respect to the quarter. As required by the new accounting guidance, we have retrospectively applied the provisions of the new accounting guidance to the calculation of net income per common unit for the periods in 2008 in the table below. As a result, basic and diluted net income per common unit remained the same as compared to amounts previously reported for the three months ended September 30, 2008. However, basic and diluted net income decreased by $0.02 and $0.01, respectively, from the amounts previously reported for the nine months ended September 30, 2008.

We then allocate to our general partner the expense related to the Class B Membership Awards to our executive officers, as our general partner will bear the cash cost of those awards. The remainder of our net income is then allocated 98% to our limited partners and 2% to our general partner. Basic net income per limited partner unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding limited partner units during the period. Diluted net income per common unit is calculated in the same manner, but also considers the impact to common units for the potential dilution from phantom units outstanding. (See Note 12 for discussion of phantom units.)

Index

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

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Numerators for basic and diluted net income per common unit:				
Net income attributable to Genesis Energy, L.P.	$4,299	$10,763	$14,045	$19,736
Less: General partner's incentive distribution to to be paid for the period	(1,729)	(728)	(4,281)	(1,790)
Add: Expense for Class B Membership Awards (Note 12)	3,088	-	7,587	-
Subtotal	5,658	10,035	17,351	17,946
Less: General partner 2% ownership	(113)	(201)	(347)	(359)
Income available for common unitholders	$5,545	$9,834	$17,004	$17,587
Denominator for basic per common unit:				
Common Units	39,480	39,452	39,467	38,796
Denominator for diluted per common unit:				
Common Units	39,480	39,452	39,467	38,796
Phantom Units	134	72	133	57
	39,614	39,524	39,600	38,853
Basic net income per common unit	$0.14	$0.25	$0.43	$0.45
Diluted net income per common unit	$0.14	$0.25	$0.43	$0.45

10. Business Segment Information

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

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

Index

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

	Pipeline Transportation	Refinery Services	Supply &Logistics	Industrial Gases (a)	Total
Three Months Ended September 30, 2009					
Segment margin (b)	$ 10,269	$12,694	$9,423	$2,893	$35,279
Maintenance capital expenditures	$ 451	$162	$723	$-	$1,336
Revenues:					
External customers	$ 10,729	$31,365	$356,783	$4,512	$403,389
Intersegment (d)	1,692	(1,359)	(333)	-	-
Total revenues of reportable segments	$ 12,421	$30,006	$356,450	$4,512	$403,389
Three Months Ended September 30, 2008					
Segment margin (b)	$ 11,474	$11,486	$9,754	$3,906	$36,620
Maintenance capital expenditures	$ 261	$351	$1,371	$-	$1,983
Revenues:					
External customers	$ 11,836	$63,492	$556,799	$4,792	$636,919
Intersegment (d)	2,589	(2,186)	(403)	-	-
Total revenues of reportable segments	$ 14,425	$61,306	$556,396	$4,792	$636,919

Index

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

	Pipeline Transportation	Refinery Services	Supply &Logistics	Industrial Gases (a)	Total
Nine Months Ended September 30, 2009					
Segment margin (b)	$ 30,841	$38,643	$21,979	$8,785	$100,248
Capital expenditures (c)	$ 2,963	$2,029	$22,274	$83	$27,349
Maintenance capital expenditures	$ 1,201	$704	$1,853	$-	$3,758
Revenues:					
External customers	$ 32,927	$117,193	$836,934	$12,032	$999,086
Intersegment (d)	4,357	(4,299)	(58)	-	-
Total revenues of reportable segments	$ 37,284	$112,894	$836,876	$12,032	$999,086
Nine Months Ended September 30, 2008					
Segment margin (b)	$ 23,396	$40,195	$21,595	$10,791	$95,977
Capital expenditures (c)	$ 80,926	$2,700	$111,575	$2,210	$197,411
Maintenance capital expenditures	$ 463	$856	$1,648	$-	$2,967
Revenues:					
External customers	$ 27,509	$167,824	$1,555,199	$13,112	$1,763,644
Intersegment (d)	6,087	(6,879)	792	-	-
Total revenues of reportable segments	$ 33,596	$160,945	$1,555,991	$13,112	$1,763,644

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

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Segment margin	$ 35,279	$ 36,620	$ 100,248	$ 95,977
Corporate general and administrative expenses	(9,141)	(4,743)	(24,218)	(15,729)
Depreciation and amortization	(15,806)	(18,100)	(47,358)	(51,610)
Net (loss) gain on disposal of surplus assets	(17)	58	141	(36)
Interest expense, net	(3,418)	(4,483)	(9,826)	(8,191)
Non-cash (credits) expenses not included in segment margin	(1,008)	1,080	(1,850)	927
Other non-cash items affecting segment margin	(1,739)	(1,318)	(2,456)	(2,979)
Income before income taxes	$ 4,150	$ 9,114	$ 14,681	$ 18,359

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

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

Index

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

11. Transactions with Related Parties

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

	Nine Months Ended September 30, 2009	2008
Truck transportation services provided to Denbury	$ 2,616	$ 2,343
Pipeline transportation services provided to Denbury	$ 10,481	$ 6,899
Payments received under direct financing leases from Denbury	$ 16,390	$ 6,056
Pipeline transportation income portion of direct financing lease fees	$ 13,754	$ 6,450
Pipeline monitoring services provided to Denbury	$ 90	$ 80
Directors' fees paid to Denbury	$ 150	$ 147
CO2 transportation services provided by Denbury	$ 4,029	$ 4,120
Crude oil purchases from Denbury	$ 1,754	$ -
Operations, general and administrative services provided by our general partner	$ 38,999	$ 38,669
Distributions to our general partner on its limited partner units and general partner interest, including incentive distributions	$ 7,055	$ 4,563
Sales of CO2 to Sandhill	$ 2,211	$ 2,217
Petroleum products sales to Davison family businesses	$ 602	$ 1,089

Transportation Services

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

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

We also provide pipeline monitoring services to Denbury. That revenue is included in pipeline revenues in our Unaudited Consolidated Statements of Operations.

Directors' Fees

We paid Denbury for the services of each of its officers who serve as directors of our general partner. The annual rate and rate for attendance at meetings are the same as the rates at which our other directors were paid.

CO2 Operations and Transportation

Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver CO_2 for us to our customers. In the first nine months of 2009, the inflation-adjusted transportation fee averaged $0.2004 per Mcf.

Index

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

Operations, General and Administrative Services

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

Amounts due to and from Related Parties

At September 30, 2009 and December 31, 2008, we owed Denbury \$1.1 million and \$1.0 million, respectively, for CO_2 transportation charges and purchases of crude oil. Denbury owed us \$1.5 million and \$2.0 million for transportation services at September 30, 2009 and December 31, 2008, respectively. We owed our general partner \$2.3 million and \$2.1 million for administrative services at September 30, 2009 and December 31, 2008, respectively. Sandhill owed us \$0.8 million and \$0.7 million for purchases of CO_2 at September 30, 2009 and December 31, 2008, respectively.

DG Marine Joint Venture

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

Financing

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

We guarantee 50% of the obligation of Sandhill to a bank. At September 30, 2009, the total amount of Sandhill's obligation to the bank was \$2.65 million; therefore, our guarantee was for \$1.33 million.

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

As discussed in Note 12, we recorded a non-cash capital contribution from our general partner of \$7.6 million for the nine months ended September 30, 2009 related to the Class B Membership Awards for our executive management team.

12. Equity-Based Compensation

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

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

Statement of Operations	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Pipeline operating costs	$124	$(87)	$208	$(206)
Refinery services operating costs	139	(8)	289	44
Supply and logistics operating costs	481	(146)	910	(198)
General and administrative expenses	3,710	(367)	9,041	(594)
Total	$4,454	$(608)	$10,448	$(954)

Index

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

Stock Appreciation Rights Plan

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

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2009	1,017,985	$18.09		
Granted during 2009	228,212	$13.00		
Exercised during 2009	(16,336)	$14.62		
Forfeited or expired during 2009	(77,034)	$18.54		
Outstanding at September 30, 2009	1,152,827	$17.13	5.9	$1,171
Exercisable at September 30, 2009	477,006	$17.73	6.0	$997

The weighted-average fair value at September 30, 2009 of rights granted during the first nine months of 2009 was $3.59 per right, determined using the following assumptions:

Assumptions Used for Fair Value of Rights Granted in 2009		
Expected life of rights (in years)	5.75	
Risk-free interest rate	2.61	%
Expected unit price volatility	44.09	%
Expected future distribution yield	8.50	%

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

At September 30, 2009, there was $1.2 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. For the awards outstanding at September 30, 2009, the remaining cost will be recognized over a weighted average period of two years.

2007 Long Term Incentive Plan

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

Non-vested Phantom Unit Grants	Number of Units	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2009	78,388	$ 19.32
Granted	82,501	$ 8.14
Vested	(27,347)	$ 19.19
Forfeited	(3,500)	$ 8.88

Non-vested at September 30, 2009	130,042	$	12.54

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

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

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

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

Class B Membership Interests

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

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

Management’s estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Changes in our assumptions will change the amount of compensation cost we record. Additionally, the determination of fair value is affected by the distribution yield of a group of publicly-traded entities that are general partners in publicly-traded master limited partnerships, a factor over which we have no control. These assumptions were used to estimate the total amount that would be paid under the Class B Membership awards through the final vesting date.

At September 30, 2009, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives is approximately $22.9 million. Management's estimates of fair value were made in order to record non-cash compensation expense over the vesting period, and do not necessarily represent the contractual amounts payable under these awards at September 30, 2009. For the three and nine months ended September 30, 2009, we recorded expense of $3.1 million and $7.6 million, respectively.

Index

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

13. Supplemental Cash Flow Information

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Decrease (increase) in:		
Accounts receivable	$ (7,513)	$ (23,670)
Inventories	(15,048)	(6,481)
Other current assets	(523)	(3,214)
Increase (decrease) in:		
Accounts payable	4,071	17,076
Accrued liabilities	(330)	5,809
Net changes in components of operating assets and liabilities, net of working capital acquired	$ (19,343)	$ (10,480)

Cash received by us for interest for the nine months ended September 30, 2009 and 2008 was $42,000 and $118,000, respectively. Payments of interest and commitment fees were $10.9 million and $8.2 million for the nine months ended September 30, 2009 and 2008, respectively.

Cash paid for income taxes during the nine months ended September 30, 2009 and 2008 was $1.0 million and $0.4 million, respectively.

At September 30, 2009, we had incurred liabilities for fixed asset and other asset additions totaling $0.3 million that had not been paid at the end of the third quarter, and, therefore, are not included in the caption “Payments to acquire fixed and intangible assets” and “Other, net” under investing activities on the Unaudited Consolidated Statements of Cash Flows. At September 30, 2008, we had incurred $0.5 million of liabilities that had not been paid at that date and are not included in “Payments to acquire fixed and intangible assets” under investing activities. Additionally, $1.0 million of fixed assets were reclassified to supplies in “Other Current Assets” in our Unaudited Consolidated Balance Sheets at September 30, 2009 due to the expected short-term utilization of the assets.

In May 2008, we issued common units with a value of $25 million as part of the consideration for the acquisition of the Free State Pipeline from Denbury. In July 2008, we issued common units with a value of $16.7 million as part of the consideration for the acquisition of the inland marine transportation assets of Grifco. These common unit issuances are non-cash transactions and the value of the assets acquired is not included in investing activities and the issuance of the common units is not reflected under financing activities in our Unaudited Consolidated Statements of Cash Flows for the nine months ended September 30, 2008.

14. Major Customers and Credit Risk

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

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

Shell Oil Company accounted for 12% and 15% of total revenues in the nine months ended September 30, 2009 and 2008, respectively. The majority of the revenues from this customer in both periods relate to our crude oil supply and logistics operations.

Index

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

15. Derivatives

On January 1, 2009, we adopted new accounting guidance which require enhanced disclosures about (1) how and why we use derivative instruments, (2) how derivative instruments and related hedged items are accounted for by us and (3) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows.

Commodity Derivatives

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

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

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

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

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

	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	253	74
Weighted average contract price per bbl	$ 66.03	$ 68.96
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	66	-
Weighted average contract price per bbl	$ 68.80	$ -
Heating oil futures:		
Contract volumes (1,000 bbls)	93	-
Weighted average contract price per gal	$ 1.86	$ -
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	10	-
Weighted average contract price per gal	$ 1.80	$ -
#6 Fuel Oil futures:		
Contract volumes (1,000 bbls)	30	-
Weighted average contract price per bbl	$ 1.44	$ -
Crude oil written calls:		
Contract volumes (1,000 bbls)	35	-
Weighted average premium received	$ 2.29	$ -
Heating oil written calls:		
Contract volumes (1,000 bbls)	10	-
Weighted average premium received	$ 3.94	$ -
Natural gas written calls:		
Contract volumes (1,000 bbls)	10	-
Weighted average premium received	$ 3.48	$ -

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 is 4.26%. DG Marine expects these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates, therefore, we have 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 is reported as a component of Accumulated Other Comprehensive Income (Loss) (AOCI) and reclassified into future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility is recorded. To the extent that the change in the fair value of the interest rate swaps does not perfectly offset the change in the fair value of our exposure to interest rates, the ineffective portion of the hedge will be immediately recognized in interest expense in our Unaudited Consolidated Statements of Operations.

Index

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

Financial Statement Impacts

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

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

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

Index

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

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

	Fair Value of Derivative Assets and Liabilities			
	Derivative Assets	Unaudited Consolidated Balance Sheets Location	Derivative Liabilities	Unaudited Consolidated Balance Sheets Location
Commodity derivatives - futures and call options:				
Hedges designated under accounting guidance as fair value hedges	$ 142	Other Current Assets	$ (1,199)(1)	Other Current Assets
Undesignated hedges	120	Other Current Assets	(668)(1)	Other Current Assets
Total commodity derivatives	262		(1,867)	
Interest rate swaps designated as cash flow hedges under accounting rules:				
Portion expected to be reclassified into earnings within one year			(1,112)	Accrued Liabilities
Portion expected to be reclassified into earnings after one year			(738)	Other Liabilities
Total derivatives	$ 262		$ (3,717)	

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

	Three Months Ended September 30, 2009 Effect on Unaudited Consolidated Statements of Operations and Other Comprehensive Income (Loss)		
	Amount of Gain (Loss) Recognized in Income		
	Supply & Logistics - Product Costs	Interest Expense Reclassified from AOCI	Other Comprehensive Income (Loss) Effective Portion

Commodity derivatives - futures and call options:								
Contracts designated as hedges under accounting guidance:	$	758	(1)	$	-		$	-
Contracts not considered hedges under accounting guidance:		1,288						
Total commodity derivatives		2,046			-			-
Interest rate swaps designated as cash flow hedges under accounting guidance					(224	)		(315)
Total derivatives	$	2,046		$	(224	)	$	(315)

(1) Represents the amount of loss recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $0.2 million.

Index

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

	Nine Months Ended September 30, 2009 Effect on Unaudited Consolidated Statements of Operations and Other Comprehensive Income (Loss) Amount of Gain (Loss) Recognized in Income		
	Supply &Logistics - Product Costs	Interest Expense Reclassified from AOCI	Other Comprehensive Income (Loss) Effective Portion
Commodity derivatives - futures and call options:			
Contracts designated as hedges under accounting guidance:	$ (4,094)(1)	$ -	$ -
Contracts not considered hedges under accounting guidance:	(1,075)		
Total commodity derivatives	(5,169)	-	-
Interest rate swaps designated as cash flow hedges under accounting guidance		(514)	(400)
Total derivatives	$ (5,169)	$ (514)	$ (400)

(1) Represents the amount of loss recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $6.4 million.

During the first nine months of 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 $1.1 million in unrealized losses from AOCI into interest expense during the next 12 months. Because a portion of these losses are based on market prices at the current period end, actual amounts to be reclassified to earnings will differ and could vary materially as a result of changes in market conditions. We have no derivative contracts with credit contingent features.

16. Fair-Value Measurements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009. 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 September 30, 2009			Fair Value at December 31, 2008		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3

Commodity derivatives:						
Assets	$ 262	$ -	$ -	$ 482	$ -	$ -
Liabilities	$ (1,867)	$ -	$ -	$ (970)	$ -	$ -
Interest rate swaps - Liabilities	$ -	$ -	$ (1,850)	$ -	$ -	$ (1,964)

Index

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

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

Level 3

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Balance at beginning of period	$ (1,759)	$ -	$ (1,964)	$ -
Realized and unrealized gains (losses)-				
Reclassified into interest expense for settled contracts	224	(5)	514	(5)
Included in other comprehensive income	(315)	(211)	(400)	(211)
Balance at end of period	$ (1,850)	$ (216)	$ (1,850)	$ (216)
Total amount of losses for the nine months ended included in earnings attributable to the change in unrealized losses relating to liabilities still held at September 30, 2009 and 2008, respectively			$ (9)	$ (2)

See Note 15 for additional information on our derivative instruments.

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

17. Contingencies

Guarantees

We guarantee to the lessor approximately $1.2 million of residual value related to leases of trailers. We also guarantee 50% of the obligations of Sandhill under a credit facility with a bank. At September 30, 2009, Sandhill owed $2.65 million; therefore our guaranty was $1.33 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year. We believe the likelihood that we would be required to perform or otherwise incur any significant losses associated with either of these guarantees is remote.

Other Matters

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

Index

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

Our facilities and operations may experience damage as a result of an accident or natural disaster. Such hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations.

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

Index

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

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

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

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

Available Cash before Reserves (a non-GAAP measure) is net income as adjusted for specific items, the most significant of which are the addition of non-cash expenses (such as depreciation), the substitution of cash generated by our joint ventures in lieu of our equity income attributable to such joint ventures, the elimination of gains and losses on asset sales (except those from the sale of surplus assets) and the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows. For additional information on Available Cash before Reserves and a reconciliation of this measure to cash flows from operations, see "Liquidity and Capital Resources - Non-GAAP Reconciliation" below.

Overview

In the third quarter of 2009, we reported net income attributable to the partnership of $4.3 million, or $0.14 per common unit. Non-cash expense related to our senior executive compensation arrangements totaling $3.1 million reduced net income during the third quarter. See additional discussion of our senior executive compensation expense in "Results of Operations – Other Costs, Interest and Income Taxes" below.

During the third quarter of 2009, we generated $23.7 million of Available Cash before Reserves, and we will distribute $15.9 million to holders of our common units and general partner for the third quarter. During the third quarter of 2009, cash provided by operating activities was $36.8 million.

Macroeconomic conditions have adversely affected business conditions in several of the industries that we service, and, consequently, us. Segment margin as compared to the third quarter of 2008, after consideration of the effects of acquisitions in 2008, declined for three of our segments. However, total segment margin increased from the first quarter to second quarter of 2009 and further increased $2.3 million in the third quarter when compared to the second quarter of 2009.

On October 13, 2009, we announced that our distribution to our common unitholders relative to the third quarter of 2009 will be $0.3525 per unit (to be paid in November 2009).   This distribution amount represents a 9.3% increase from our distribution of $0.3225 per unit for the third quarter of 2008. During the third quarter of 2009, we paid a distribution of $0.3450 per unit related to the second quarter of 2009.

Index

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

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

Available Cash before Reserves

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income attributable to Genesis Energy, L.P.	$4,299	$10,763	$14,045	$19,736
Depreciation and amortization	15,806	18,100	47,358	51,610
Cash received from direct financing leases not included in income	951	893	2,787	1,437
Cash effects of sales of certain assets	156	147	613	573
Effects of available cash generated by equity method investees not included in income	787	401	(332)	1,467
Cash effects of stock-based compensation plans	(77)	(113)	(84)	(384)
Non-cash tax (benefit) expense	(3)	(2,462)	1,084	(3,388)
Earnings of DG Marine in excess of distributable cash	(1,108)	(428)	(3,982)	(428)
Non-cash equity-based compensation expense (benefit)	4,454	(610)	10,448	(958)
Other non-cash items, net	(214)	(1,156)	(914)	(1,174)
Maintenance capital expenditures	(1,336)	(1,983)	(3,758)	(2,967)
Available Cash before Reserves	$23,715	$23,552	$67,265	$65,524

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the three and nine months ended September 30, 2009 and 2008 in "Liquidity and Capital Resources – Non-GAAP Reconciliation" below. For the three and nine months ended September 30, 2009, cash flows provided by operating activities were $36.8 million and $55.8 million, respectively. For the three and nine months ended September 30, 2008, cash flows provided by operating activities were $33.5 million and $56.2 million, respectively.

Index

Results of Operations

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)		(in thousands)	
Pipeline transportation	$10,269	$11,474	$30,841	$23,396
Refinery services	12,694	11,486	38,643	40,195
Supply and logistics	9,423	9,754	21,979	21,595
Industrial gases	2,893	3,906	8,785	10,791
Total segment margin	$35,279	$36,620	$100,248	$95,977

Pipeline Transportation Segment

Operating results for our pipeline transportation segment were as follows:

Pipeline System	Three Months Ended September 30 2009	Three Months Ended September 30 2008	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008	
Mississippi-Bbls/day	22,643	25,232	24,046	24,323	
Jay - Bbls/day	10,550	13,817	9,767	13,422	
Texas - Bbls/day	24,593	25,627	26,477	28,298	
Free State - Mcf/day	133,038	155,131	146,160	154,408	(1)

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$4,511	$4,228	$12,461	$12,333
Non-income payments under direct financing leases	951	893	2,787	1,437
Sales of crude oil pipeline loss allowance volumes	922	2,333	3,127	7,659
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	6,361	6,647	19,481	8,971
Tank rental reimbursements and other miscellaneous revenues	171	35	488	468
Revenues from natural gas tariffs and sales	456	1,182	1,727	4,165
Natural gas purchases	(395)	(1,136)	(1,519)	(3,990)
Pipeline operating costs, excluding non-cash charges for our equity-based compensation plans and other non-cash charges	(2,708)	(2,708)	(7,711)	(7,647)
Segment margin	$10,269	$11,474	$30,841	$23,396

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

Pipeline segment margin for the third quarter of 2009 decreased $1.2 million as compared to the third quarter of 2008. The significant components of this change were as follows:

- A decrease in revenues from sales of pipeline loss allowance volumes reduced segment margin by $1.4 million. The decline in market prices for crude oil reduced the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil market prices decreased approximately $50 per barrel between the two quarters. In addition, pipeline loss allowance volumes decreased approximately 5,600 barrels between the periods.

Index

- A decline in volumes transported on our crude oil pipelines between the two periods decreased segment margin by \$0.4 million. The decreased volumes were principally due to a producer connected to our Jay System shutting in production in 2009 due to the decline in crude oil prices in the latter half of 2008. Volume fluctuations on the Mississippi System, where the incremental tariff rate is only \$0.25 per barrel, are primarily a result of Denbury's crude oil production activities. The impact of volume decreases on the Texas System on revenues is not very significant due to the relatively low tariffs on that system. Approximately 77% of the volume on that system in the third quarter was shipped on a tariff of \$0.31 per barrel.

- A decrease in revenues and payments related to CO_2 pipelines of \$0.3 million between the two quarters, although an increase of \$0.1 million in payments under direct financing leases not affecting income partially offset this decrease. The remaining \$0.2 million decrease was related to the Free State pipeline. The average volume transported on the Free State pipeline for the third quarter of 2009 was 133 MMcf per day, with the transportation fees and the minimum payments totaling \$1.6 million and \$0.3 million, respectively. Transportation fees and the minimum payments for the 2008 third quarter were \$1.9 million and \$0.3 million, respectively, with the average transportation volume at 155 MMcf per day. Denbury has exclusive use of this pipeline and variations in its CO_2 tertiary oil recovery activities create the fluctuations in the volumes transported on the Free State pipeline.

- Tariff rate increases of approximately 7.6% on our Jay and Mississippi pipelines went into effect July 1, 2009, partially mitigating the effects of lower crude oil pipeline volumes. The rate increases increased segment margin between the two periods by approximately \$0.7 million.

Nine Months Ended September 30, 2009 Compared with Nine Months Ended September 30, 2008

Pipeline segment margin between the nine month periods increased \$7.4 million. The significant component of this change was an increase in revenues from CO_2 financing leases and tariffs of \$10.5 million and a related increase in non-income payments from the same financing leases of \$1.4 million. The nine-month period in 2008 only included results from the NEJD and Free State CO_2 pipelines for a four-month period while the 2009 period included nine months of results.

Partially offsetting these increases was a decrease in revenues from sales of pipeline loss allowance volumes of \$4.5 million related almost exclusively to the significant decline (an average of \$56 per barrel) in crude oil prices between the two periods.

Index

Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Volumes sold:				
NaHS volumes (Dry short tons "DST")	28,207	38,319	75,344	126,716
NaOH volumes (DST)	26,898	18,404	63,561	51,066
Total	55,105	56,723	138,905	177,782
NaHS revenues	$22,654	$43,926	$74,754	$121,738
NaOH revenues	6,455	13,439	33,534	38,892
Other revenues	2,256	6,127	8,905	7,194
Total external segment revenues	$31,365	$63,492	$117,193	$167,824
Segment margin	$12,694	$11,486	$38,643	$40,195
Average index price for NaOH per DST (1)	$198	$845	$493	$616
Raw material and processing costs as % of segment revenues	33 %	66 %	47 %	62 %
Delivery costs as a % of segment revenues	14 %	13 %	11 %	14 %

(1) Source: Harriman Chemsult Ltd.

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

Refinery services segment margin for the third quarter of 2009 was $12.7 million, an increase of $1.2 million, or 10.5%, from the comparative period in 2008. The significant components of this fluctuation were as follows:

- A decline in NaHS volumes of 26%. Macroeconomic conditions have negatively impacted the demand for NaHS, primarily in mining and industrial activities. As market prices and demand for copper and molybdenum improve, we would expect demand for NaHS to increase. Similarly, improvements in industrial activities including the paper and pulp and tanning industries would likely improve NaHS demand.

- An increase in NaOH sales volumes of 46%. NaOH (or caustic soda) is a key component in the provision of our services for which we receive the by-product NaHS. We are a very large consumer of caustic soda, and our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties.

- Volatile caustic soda prices. Average index prices for caustic soda increased throughout 2008 to a high of approximately $950 per DST in the fourth quarter of 2008. Since that time market prices of caustic soda have decreased to approximately $200 per DST. This volatility affects both the cost of caustic soda used to provide our services as well as the price at which we sell NaHS.

- Aggressive management of production costs. Raw material and processing costs related to providing our refinery services and supplying caustic soda as a percentage of our segment revenues declined 33% between the periods. The key component in the provision of our refinery services is caustic soda. In addition, as discussed above, we also market caustic soda. As the market price of caustic soda has fluctuated in 2008 and 2009, we have managed our acquisition costs through the timing of our purchases and our logistics costs related to our caustic soda purchases.   We have also taken steps to reduce processing costs.

Index

- Slightly higher delivery logistics costs. The costs of delivering NaHS and caustic soda to our customers increased slightly as a percentage of segment revenues by 1% between the two quarterly periods. We experienced this slight increase in logistics costs as a percentage of revenues primarily due to the change in revenues. Freight demand and fuel prices declined in the 2009 period as economic conditions reduced demand for transportation services and the decline in crude oil prices reduced the cost of fuel used in transporting these products. In 2009, we have also adjusted the modes of transportation being used to transport NaHS and caustic soda between rail, barge and truck to improve total logistics costs.

Nine Months Ended September 30, 2009 Compared with Nine Months Ended September 30, 2008

Segment margin for our refinery services decreased $1.6 million between the nine months ended September 30, 2009 and the same period in 2008. The reasons for this decline were similar to the quarterly comparison as follows:

- NaHS volumes declined 41%, as a result of macroeconomic conditions.

- Caustic soda sales volumes increased 24% partly offsetting the impact of the decline in NaHS activity.

- Revenues decreased 30% as average index prices for caustic soda in the nine months ended September 30, 2009 ranged from approximately $900 per DST in January to $200 per DST in September as compared to an increasing range of approximately $450 to $950 per DST in the 2008 period. As the majority of our NaHS sales prices fluctuate with the market price of caustic soda, variations in market prices affect our revenues. Raw material and processing costs as a percentage of segment revenues declined 15% between periods due to us managing the timing of our purchases and the influences of our ability to purchase in bulk at favorable prices.

- Delivery costs declined due to freight demand in the market and fuel prices.

Supply and Logistics Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Supply and logistics revenue	$356,450	$556,396	$836,876	$1,555,991
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(323,951)	(521,779)	(753,217)	(1,471,254)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based compensation and other non-cash expenses	(23,076)	(24,863)	(61,680)	(63,142)
Segment margin	$9,423	$9,754	$21,979	$21,595
Volumes of crude oil and petroleum products -average barrels per day	51,260	47,342	47,280	47,694

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

The average market prices of crude oil and petroleum products declined by more than $50 per barrel, or approximately 45%, although our segment margin declined by only $0.3 million, or 3.4%, comparatively between the third quarters of 2009 and 2008. The price volatility had a limited impact on our segment margin.

The key factors affecting the two quarters were as follows:

- Segment margin generated by DG Marine’s inland marine barge operations (increased segment margin by $1.7 million);

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

- Reduction in opportunities to purchase and blend crude oil and products (reduced segment margin by $2.9 million).

The inland marine transportation operations of Grifco Transportation, acquired by DG Marine in mid-July of 2008, contributed $1.7 million more to segment margin in the third quarter of 2009 as compared to the third quarter of 2008. These operations provided us with an additional capability to provide transportation services of petroleum products by barge. As part of the acquisition, DG Marine acquired six tows (a tow consists of a push boat and two barges.) A total of four additional tows added during the fourth quarter of 2008 and first half of 2009 generated the segment margin increase despite declines in average charter rates for the tows over the same period.

During the third quarter of 2009, crude oil markets were in contango (oil prices for future deliveries are higher than for current deliveries), providing an opportunity for us to purchase and store crude oil as inventory for delivery in future months. The crude oil markets were not in contango in the third quarter of 2008 sufficiently to support the costs associated with storing inventory. During the third quarter of 2009, we held an average of approximately 220,000 barrels of crude oil in our storage tanks and hedged this volume with futures contracts on the NYMEX. We are accounting for the effects of this inventory position and related derivative contracts as a fair value hedge under accounting guidance. The effect on segment margin for the amount excluded from effectiveness testing related to this fair value hedge was a $0.9 million gain in the third quarter of 2009.

Offsetting these improvements in segment margin was a decrease in the margins from our crude oil gathering and petroleum products marketing operations. In 2009, we experienced some reductions in volumes as a result of crude oil producers’ choices to reduce operating expenses or postpone development expenditures that could have maintained or enhanced their existing production levels. As a consequence of the reductions in volumes, our segment margin from crude oil gathering declined between the quarterly periods by $1.0 million. Volatile price changes in the petroleum products markets and robust refinery utilization in the third quarter of 2008 created blending and sales opportunities with expanded margins in comparison to historical rates. Relatively flat petroleum prices and reduced refinery utilization in the third quarter of 2009 narrowed the economics of our blending opportunities and reduced sales margins to more historical rates. Somewhat offsetting these margin declines were the additional opportunities to handle volumes from the heavy end of the refined barrel due to our access to additional leased heavy products storage capacity and to barge transportation capabilities through DG Marine. However, the net result of these factors was a reduction of our segment margin of $1.9 million from petroleum products and related activities.

Nine Months Ended September 30, 2009 as Compared to Nine Months Ended September 30, 2008

Segment margin for the nine month period in 2009 was affected by the same factors as in the third quarter, although the result was a slight increase in segment margin of $0.4 million. For the nine-month periods, the key factors described above had an impact as follows:

- Acquisition of inland marine transportation operations of Grifco in mid-July of 2008 (increased segment margin by $7.3 million);

- Reduction in opportunities to purchase and blend crude oil and petroleum products (reduced segment margin by $9.2 million); and

- Crude oil contango market conditions (increased segment margin by $2.3 million).

Industrial Gases Segment

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

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

Index

Our industrial customers treat the CO2 and transport it to their customers. The primary industrial applications of CO2 by those customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through the third quarter of 2009, we expect some seasonality in our sales of CO2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. Our industrial customers also provide CO2 to companies engaged in tertiary oil recovery activities.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Revenues from CO2 marketing	$4,512	$4,792	$12,032	$13,112
CO2 transportation and other costs	(1,619)	(1,503)	(4,298)	(4,166)
Available cash generated by equity investees	-	617	1,051	1,845
Segment margin	$2,893	$3,906	$8,785	$10,791
Volumes per day:				
CO2 marketing - Mcf	80,520	83,816	73,697	78,967

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

Segment margin from the industrial gases segment decreased between the 2009 and 2008 third quarters due to a decline in volumes and a slight decrease in the average sales price of CO2 to our customers. Volumes declined 4% between the two quarterly periods as customers reduced purchases. The average sales price of CO2 decreased $0.01 per Mcf, or 2%, due to variations in the volumes sold among contracts with different pricing terms.

Our industrial gases segment experienced increased costs due to inflationary adjustments to the rates Denbury charges us to transport CO2 to our customers. Average transportation rates increased by 6.0% over the average rates in the 2008 third quarter.

Our share of the available cash before reserves generated by our equity investments in each quarterly period primarily resulted from our investment in T&P Syngas. In the third quarter of 2009, T&P Syngas performed a scheduled turnaround at its facility that decreased its revenues and increased its maintenance expenses. Additionally, T&P Syngas incurred expenses related to improving its waste water treatment. These activities were completed during the third quarter and the cost of these activities will be paid from funds generated by T&P Syngas.

Nine Months Ended September 30, 2009 Compared with Nine Months Ended September 30, 2008

The decrease in margin from the industrial gases segment between the two nine-month periods was the result of a decrease in volumes sold and a decrease in the average sales price of CO2 to our customers. During the first nine months of 2009, volumes declined 7% to the comparable 2008 period as customers reduced volumes while performing maintenance activities at their facilities. Variations in the volumes sold among contracts with different pricing terms resulted in the average sales price of the CO2 decreasing $0.01 per Mcf, or 1%.

The inflation adjustment to the rates we pay Denbury to transport the CO2 to our customers resulted in greater CO2 transportation costs in the first nine months of 2009 when compared to the same 2008 period. The transportation rate increase between the two periods was 5.0%.

Our share of the available cash before reserves generated by our equity investments in each period primarily resulted from our investment in T&P Syngas. As discussed above, the fluctuation between the nine-month periods is attributable to scheduled maintenance activities.

Index

Other Costs, Interest, and Income Taxes

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Total general and administrative expenses	$10,128	$9,239	$27,188	$26,929

Comparing the three-month periods and the nine-month periods, the primary factor driving the increase in general administrative expenses related to the charge recorded for the compensation arrangement between our senior executive team and our general partner. On December 31, 2008, our general partner and our senior executive management team entered into a compensation arrangement whereby our executive team may earn an interest in our incentive distribution rights owned by our general partner. While our general partner will bear the cash cost of this compensation with our senior executives, we record the expense of the arrangements with an offsetting non-cash capital contribution by our general partner. As discussed in Note 12 under Class B Membership Interests, we estimate the fair value of the awards to our senior executives at each reporting date and adjust the expense we have recorded based on that fair value. Based on the fair value estimate at September 30, 2009 of $22.9 million, we recorded expense for the third quarter of 2009 of $3.1 million, and a total of $7.6 million for the first nine months in 2009. The fair value of the awards is being recorded on an accelerated basis due to the vesting conditions contained in the awards, so as to match the expense recorded to the service period required for vesting.

Reductions in audit, tax and other professional services and further integration of the operations we acquired in 2007 offset a portion of the increased amounts in the three and nine month periods from the compensation arrangement.

Depreciation and amortization expense. Depreciation and amortization expense decreased by $4.3 million between the nine-month periods ended September 30 primarily as a result of the amortization expense recognized on intangible assets. For the third quarter periods, the decrease in depreciation and amortization expense was $2.3 million, with a decline in intangible amortization offset by depreciation on the DG Marine assets acquired in July 2008.

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

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Interest expense, including commitment fees, excluding DG Marine	$2,018	$3,516	$5,799	$7,229
Amortization of facility fees, excluding DG Marine facility	167	167	495	497

Interest expense and commitment fees - DG Marine	1,254	965	3,699	965
Capitalized interest	(3)	(47)	(112)	(148)
Interest income	(18)	(118)	(55)	(352)
Net interest expense	$3,418	$4,483	$9,826	$8,191

Our average debt balance was $24.3 million higher in the third quarter of 2009 than the same period in 2008, although lower market interest rates more than offset the effect on interest expense. Our average interest rate was 2.0% lower during the 2009 quarter, resulting in a decrease for the quarter of $1.5 million in interest expense. DG Marine incurred interest expense of $1.3 million and $1.0 in the third quarter of 2009 and 2008, respectively, under its credit facility.

Index

For the nine-month periods, our average outstanding debt balance was $151.6 million greater in 2009 than 2008. Our average interest rate was 2.4% less in the 2009 period than the 2008 period, resulting in lower interest cost. For the nine month periods, DG Marine's interest expense was $3.7 million and $1.0 million under its credit facility, respectively. The increase was a result of the 2009 period including nine months whereas the 2008 period only included interest expense since the July 2008 acquisition.

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. In the nine months of 2009, our activities from operations conducted in corporations increased in relation to the prior year period, resulting in increased income tax expense. 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

Although credit and access to capital continue to be negatively impacted by current economic conditions in our business environment, recent market trends have indicated improvements in bank lending capacity and long-term interest rates. We anticipate that our short-term working capital needs will be met through our current cash balances, future internally-generated funds and funds available under our credit facility. Existing capacity in our credit facility and $8.7 million of cash on hand, as well as the absence of any need to access the capital markets, may allow us to take advantage of attractive acquisition and/or growth opportunities that develop.

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

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

Our consolidated balance sheet at September 30, 2009 includes total long-term debt of $384.4 million, consisting of $49.4 million outstanding under the non-recourse DG Marine credit facility and $335 million outstanding under our credit facility. Outstanding letters of credit under our credit facility at September 30, 2009 were $4.1 million. Our borrowing base under our $500 million credit facility is a function of our EBITDA (earnings before interest, taxes, depreciation and amortization), as defined in our credit agreement for our most recent four calendar quarters.

Our credit facility has provisions that allow us to increase our borrowing base for material acquisitions. Upon the completion of four full quarters of operations including the acquired operations, the EBITDA multiple used to determine our borrowing base is reduced from 4.75 times to 4.25 times. In mid-August, upon reporting to our lenders our fourth full quarter of operations including the pipeline dropdown transactions from Denbury that occurred in May

2008, our borrowing base was calculated using our last four quarters of EBITDA with a 4.25 multiplier, which resulted in a decrease in our borrowing base to $419 million. This decrease in the borrowing base resulted in approximately $80 million of remaining credit as of September 30, 2009 in addition to cash on hand and cash that we have temporarily invested in crude oil and petroleum products inventories. We believe that this level of credit will provide us sufficient liquidity to operate our business. We have committed capital available under our credit facility up to $500 million that we can access for material acquisitions that meet criteria specified in our credit agreement with the calculation of our borrowing base using the higher multiple and an agreed-upon amount of pro forma EBITDA associated with the acquisition.

Index

DG Marine had $49.4 million of loans outstanding under its $90 million credit facility. As of September 30, 2009, DG Marine had completed and paid for all amounts related to the capital expenditure projects related to the expansion of its fleet.

During 2009, as refineries have reduced production capacity, demand for transportation services of heavy-end fuel oils by inland barges has weakened, putting pressure on the rates DG Marine can charge for its services. In response, DG Marine amended its credit facility to (i) adjust the definition of interest expense for purposes of the interest coverage ratio to exclude non-cash interest expense and interest under the subordinated loan agreement between DG Marine and Genesis; (ii) permit Genesis to guaranty up to $7.5 million of the outstanding balance under the DG Marine credit facility; (iii) reduce the maximum amount of the DG Marine credit facility from $90 million to $54 million due to the completion of its fleet expansion projects; and (iv) to provide a debt structure that would allow for additional credit support in certain circumstances. On October 30, 2009, Genesis loaned the remaining $8 million available under the $25 million Subordinated Loan Agreement to DG Marine. The proceeds of the loan were used to reduce the amount outstanding under the DG Marine credit facility.

Uses of Cash

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

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

Debt and Other Financing Activities. Our sources of cash are primarily from operations and our credit facilities. Our net borrowings under our credit facility and the DG Marine credit facility totaled $9.1 million during the first nine months of 2009. These borrowings related primarily to the investment in fixed assets and the payment of liabilities accrued at year end for such items as annual bonus payments and property tax obligations. Additionally, funds were utilized to increase our crude oil inventory levels due to the contango market conditions. We paid distributions totaling $44.1 million to our limited partners and our general partner during the first nine months of 2009. See the details of distributions paid in “Distributions” below.

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

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

Index

Capital Expenditures, and Business and Asset Acquisitions

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

	Nine Months Ended September 30, 2009	2008
	(in thousands)	
Capital expenditures for property, plant and equipment:		
Maintenance capital expenditures:		
Pipeline transportation assets	1,201	463
Supply and logistics assets	1,269	571
Refinery services assets	704	856
Administrative and other assets	584	1,077
Total maintenance capital expenditures	3,758	2,967
Growth capital expenditures:		
Pipeline transportation assets	1,762	5,463
Supply and logistics assets	17,920	18,831
Refinery services assets	1,326	1,844
Total growth capital expenditures	21,008	26,138
Total	24,766	29,105
Capital expenditures for asset purchases:		
DG Marine acquisition	-	91,096
Free State Pipeline acquisition	-	75,000
Acquisition of intangible assets	2,500	-
Total asset purchases	2,500	166,096
Capital expenditures attributable to unconsolidated affiliates:		
Faustina project	83	2,210
Total	83	2,210
Total capital expenditures	$ 27,349	$ 197,411

During the remainder of 2009, we expect to expend approximately $1.4 million for maintenance capital projects in progress or planned. We also plan to spend $2.5 million for the first phase of a project to integrate and upgrade our information technology systems as a result of our growth in 2007 and 2008 and to be positioned for future growth. Capital expenditures in 2010 have not yet been finalized, although we expect to expend an additional $6 million to $8 million on our information systems.

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

Distributions

We are required by our partnership agreement to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last seven quarters, including the distribution to be paid for the third quarter of 2009, as shown in the table below (in thousands, except per unit amounts).

Index

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009 (1)	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931

(1) This distribution will be paid on November 13, 2009 to our general partner and unitholders of record as of November 2, 2009.

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

Non-GAAP Reconciliation

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

Available Cash before Reserves, also referred to as discretionary cash flow, is commonly used as a supplemental financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (1) the financial performance of our assets without regard to financing methods, capital structures, or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest 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.

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

Index

The reconciliation of Available Cash before Reserves (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three and nine months ended September 30, 2009 and 2008 is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in thousands)		(in thousands)	
Cash flows from operating activities	$36,765	$33,534	$55,831	$56,230
Adjustments to reconcile operating cash flows to Available Cash:				
Maintenance capital expenditures	(1,336)	(1,983)	(3,758)	(2,967)
Proceeds from sales of certain assets	156	147	613	573
Amortization of credit facility issuance fees	(487)	(427)	(1,448)	(962)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	-	482	251	895
Earnings of DG Marine in excess of distributable cash	(1,108)	(428)	(3,982)	(428)
Other items affecting available cash	(778)	(19)	415	1,703
Net effect of changes in operating accounts not included in calculation of Available Cash	(9,497)	(7,754)	19,343	10,480
Available Cash before Reserves	$23,715	$23,552	$67,265	$65,524

Commitments and Off-Balance-Sheet Arrangements

Contractual Obligations and Commercial Commitments

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

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under "Contractual Obligations and Commercial Commitments" in our Annual Report on Form 10-K for the year ended December 31, 2008, nor do we have any debt or equity triggers based upon our unit or commodity prices.

New Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2, "Recent Accounting Developments" in the accompanying unaudited consolidated financial statements.

Forward Looking Statements

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

Index

- demand for, the supply of, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or "NGLs", sodium hydrosulfide and caustic soda in the United States, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;
- throughput levels and rates;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and consummate strategic acquisitions, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;
- shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;
- changes in laws or regulations to which we are subject;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of existing debt agreements that contain restrictive financial covenants;
- loss of key personnel;
- the effects of competition, in particular, by other pipeline systems;
- hazards and operating risks that may not be covered fully by insurance;
- the condition of the capital markets in the United States;
- loss or bankruptcy of key customers;
- the political and economic stability of the oil producing nations of the world; and
- general economic conditions, including rates of inflation and interest rates.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2008. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Index

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

	Sell (Short) Contracts	Buy (Long) Contracts
Futures Contracts:		
Crude Oil:		
Contract volumes (1,000 bbls)	319	74
Weighted average price per bbl	$ 66.60	$ 68.96
Contract value (in thousands)	$ 21,246	$ 5,103
Mark-to-market change (in thousands)	1,341	137
Market settlement value (in thousands)	$ 22,587	$ 5,240
Heating Oil:		
Contract volumes (1,000 bbls)	93	-
Weighted average price per gal	$ 1.86	$ -
Contract value (in thousands)	$ 7,259	$ -
Mark-to-market change (in thousands)	122	-
Market settlement value (in thousands)	$ 7,381	$ -
RBOB Gasoline:		
Contract volumes (1,000 bbls)	10	-
Weighted average price per gal	$ 1.80	$ -
Contract value (in thousands)	$ 754	$ -
Mark-to-market change (in thousands)	(5)	-
Market settlement value (in thousands)	$ 749	$ -
#6 Fuel Oil:		
Contract volumes (1,000 bbls)	30	-
Weighted average price per gal	$ 1.44	$ -
Contract value (in thousands)	$ 1,812	$ -
Mark-to-market change (in thousands)	69	-
Market settlement value (in thousands)	$ 1,881	$ -

Index

NYMEX Option Contracts:

Crude Oil- Written Calls				
Contract volumes (1,000 bbls)		35		-
Weighted average premium received/paid	$	2.29	$	-
Contract value (in thousands)	$	80	$	-
Mark-to-market change (in thousands)		43		-
Market settlement value (in thousands)	$	123	$	-
Heating Oil- Written Calls				
Contract volumes (1,000 bbls)		10		-
Weighted average premium received/paid	$	3.94	$	-
Contract value (in thousands)	$	39	$	-
Mark-to-market change (in thousands)		(3)		-
Market settlement value (in thousands)	$	36	$	-
Natural Gas- Written Calls				
Contract volumes (1,000 bbls)		10		-
Weighted average premium received/paid	$	3.48	$	-
Contract value (in thousands)	$	35	$	-
Mark-to-market change (in thousands)		22		-
Market settlement value (in thousands)	$	57	$	-

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, 2008. There have been no material developments in legal proceedings since the filing of such Form 10-K.

Item 1A. Risk Factors.

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2008. There have been no material changes to the risk factors since the filing of such Form 10-K.

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

None.

Index

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

Item 6. Exhibits

(a) Exhibits.

3.1 Certificate of Limited Partnership of Genesis Energy, L.P. ("Genesis") (incorporated by reference to Exhibit 3.1 to Registration Statement, File No. 333-11545)

3.2 Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 4.1 to Form 8-K dated June 15, 2005)

3.3 Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 2007.)

3.4 Certificate of Limited Partnership of Genesis Crude Oil, L.P. ("the Operating Partnership") (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 1996)

3.5 Fourth Amended and Restated Agreement of Limited Partnership of the Operating Partnership (incorporated by reference to Exhibit 4.2 to Form 8-K dated June 15, 2005)

3.6 Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009.)

3.7 Certificate of Formation of Genesis Energy, LLC (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009.)

3.8 Limited Liability Company Agreement of Genesis Energy, LLC dated December 29, 2008 (incorporated by reference to Exhibit 3.3 to Form 8-K dated January 7, 2009.)

3.9 First Amendment to Limited Liability Company Agreement of Genesis Energy, LLC dated December 31, 2008 (incorporated by reference to Exhibit 3.4 to Form 8-K dated January 7, 2009.)

4.1 Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2007.)

31.1 *Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.

31.2 *Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.

32 *Certification by Chief Executive Officer and Chief Financial Officer Pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934.

*Filed herewith

Index

SIGNATURES

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

		GENESIS ENERGY, L.P. (A Delaware Limited Partnership)
	By:	GENESIS ENERGY, LLC, as General Partner
Date: November 9, 2009	By:	/s/ Robert V. Deere Robert V. Deere Chief Financial Officer