GENESIS ENERGY LP
Form 10-Q
November 01, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2013
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 jurisdiction of incorporation or organization)	76-0513049 (I.R.S. Employer Identification No.)
919 Milam, Suite 2100, Houston, TX (Address of principal executive offices)	77002 (Zip code)

Registrant's telephone number, including area code: (713) 860-2500

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 ý 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 ý 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 x Accelerated filer ¨ 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 ý
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. There were 88,650,988 Class A Common Units and 39,997 Class B Common Units outstanding as of October 31, 2013.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
GENESIS ENERGY, L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except units)

	September 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$16,859	$11,282
Accounts receivable - trade, net	364,080	270,925
Inventories	119,122	87,050
Other	24,008	34,777
Total current assets	524,069	404,034
FIXED ASSETS, at cost	1,155,977	723,225
Less: Accumulated depreciation	(186,640)	(157,944)
Net fixed assets	969,337	565,281
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	153,300	157,385
EQUITY INVESTEES	605,067	549,235
INTANGIBLE ASSETS, net of amortization	65,753	75,065
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	36,998	33,618
TOTAL ASSETS	$2,679,570	$2,109,664
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$340,531	$258,053
Accrued liabilities	69,674	54,598
Total current liabilities	410,205	312,651
SENIOR SECURED CREDIT FACILITY	411,300	500,000
SENIOR UNSECURED NOTES	700,804	350,895
DEFERRED TAX LIABILITIES	13,625	13,810
OTHER LONG-TERM LIABILITIES	17,419	15,813
COMMITMENTS AND CONTINGENCIES (Note 14)		
PARTNERS' CAPITAL:		
Common unitholders, 88,690,985 and 81,202,752 units issued and outstanding at September 30, 2013 and December 31, 2012	1,126,217	916,495
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$2,679,570	$2,109,664

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
REVENUES:				
Supply and logistics	$1,184,191	$974,696	$3,400,786	$2,815,849
Refinery services	52,410	47,977	153,370	144,342
Pipeline transportation services	23,217	19,164	66,533	55,794
Total revenues	1,259,818	1,041,837	3,620,689	3,015,985
COSTS AND EXPENSES:				
Supply and logistics product costs	1,116,871	911,399	3,185,302	2,630,444
Supply and logistics operating costs	50,870	40,953	146,235	119,576
Refinery services operating costs	33,040	29,243	98,304	91,072
Pipeline transportation operating costs	6,278	5,911	20,507	15,995
General and administrative	12,095	10,375	35,156	29,934
Depreciation and amortization	16,066	14,838	46,789	45,447
Total costs and expenses	1,235,220	1,012,719	3,532,293	2,932,468
OPERATING INCOME	24,598	29,118	88,396	83,517
Equity in earnings of equity investees	7,059	3,432	16,618	7,971
Interest expense	(12,587)	(9,873)	(36,282)	(30,697)
Income before income taxes	19,070	22,677	68,732	60,791
Income tax (expense) benefit	(596)	8,517	(510)	8,591
NET INCOME	$18,474	$31,194	$68,222	$69,382
NET INCOME PER COMMON UNIT:				
Basic and Diluted	$0.22	$0.39	$0.83	$0.90
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:				
Basic and Diluted	83,878	79,901	82,361	77,410

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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

	Number of Common Units		Partners' Capital	
	2013	2012	2013	2012
Partners' capital, January 1	81,203	71,965	$916,495	$792,638
Net income	—	—	68,222	69,382
Cash distributions	—	—	(122,097)	(104,008)
Issuance of common units for cash, net	5,750	5,750	263,597	169,421
Conversion of waiver units	1,738	3,476	—	—
Other	—	12	—	500
Partners' capital, September 30	88,691	81,203	$1,126,217	$927,933

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$68,222	$69,382
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation and amortization	46,789	45,447
Amortization of debt issuance costs and premium	3,234	2,655
Amortization of unearned income and initial direct costs on direct financing leases	(12,160)	(12,641)
Payments received under direct financing leases	15,946	16,389
Equity in earnings of investments in equity investees	(16,618)	(7,971)
Cash distributions of earnings of equity investees	24,352	16,151
Non-cash effect of equity-based compensation plans	10,579	4,617
Deferred and other tax liabilities	(186)	(9,156)
Unrealized gains on derivative transactions	(2,802)	(1,251)
Other, net	336	438
Net changes in components of operating assets and liabilities (Note 11)	(28,354)	18,878
Net cash provided by operating activities	109,338	142,938
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(199,634)	(116,702)
Cash distributions received from equity investees - return of investment	8,272	10,918
Investments in equity investees	(71,443)	(57,072)
Acquisitions	(230,921)	(205,576)
Proceeds from asset sales	810	667
Other, net	(1,004)	(1,012)
Net cash used in investing activities	(493,920)	(368,777)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on senior secured credit facility	1,234,500	1,407,000
Repayments on senior secured credit facility	(1,323,200)	(1,333,300)
Proceeds from issuance of senior unsecured notes, including premium	350,000	101,000
Debt issuance costs	(8,157)	(7,109)
Issuance of common units for cash, net	263,597	169,421
Distributions to common unitholders	(122,097)	(104,008)
Other, net	(4,484)	(2,521)
Net cash provided by financing activities	390,159	230,483
Net increase in cash and cash equivalents	5,577	4,644
Cash and cash equivalents at beginning of period	11,282	10,817
Cash and cash equivalents at end of period	$16,859	$15,461

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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

1. Organization and Basis of Presentation and Consolidation
Organization
We are a limited partnership focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida and in the Gulf of Mexico. We have a diverse portfolio of assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and trucks. We were formed in 1996 and are owned 100% by our limited partners. Genesis Energy, LLC, our general partner, is a wholly-owned subsidiary. Our general partner has sole responsibility for conducting our business and managing our operations. We conduct our operations and own our operating assets through our subsidiaries and joint ventures. We manage our businesses through the following three divisions that constitute our reportable segments:

- Pipeline transportation of interstate, intrastate and offshore crude oil, and, to a lesser extent, carbon dioxide (or "CO_2");
- Refinery services involving processing of high sulfur (or “sour”) gas streams for refineries to remove the sulfur, and selling the related by-product, sodium hydrosulfide (or “NaHS”, commonly pronounced "nash"); and
- Supply and logistics services, which include terminaling, blending, storing, marketing, and transporting crude oil and petroleum products and, on a smaller scale, CO_2.

Basis of Presentation and Consolidation
The accompanying Unaudited Condensed Consolidated Financial Statements include Genesis Energy, L.P. and its subsidiaries, including Genesis Energy, LLC, our general partner.
Our results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. The Condensed Consolidated Financial Statements included herein have been prepared by us without audit pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, they reflect all adjustments (which consist solely of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of the financial results for interim periods. Certain information and notes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) 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, 2012.
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.
Immaterial Restatement
Revenues and cost of sales for 2012 include corrections to previously reported quarterly and annual amounts for the three and nine months ended September 30, 2012. These corrections were made to present certain sales transactions on a gross basis that previously had been recorded on a net basis. The corrections had no effect on previously reported operating income, net income or Segment Margin.

2. Acquisition

Offshore Marine Transportation Business

In August 2013, we completed the acquisition of substantially all of the assets of the downstream transportation business of Hornbeck Offshore Services, Inc. for $230.9 million, which we refer to as our offshore marine transportation business and assets. The total acquisition cost has been allocated to fixed assets based on estimated preliminary fair values. Such preliminary fair values were developed by management. We do not expect any material adjustments to these preliminary purchase price allocations as a result of the final valuation. The acquired business was primarily comprised of nine barges and nine tug boats which transport crude oil and refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Eastern Seaboard, Great Lakes and Caribbean. That acquisition complements and further integrates our existing operations, including our Genesis Marine inland barge business (comprised of 50 barges and 23 push/tow boats), our

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crude oil and heavy refined products storage and blending terminals as well as our crude oil pipeline systems. That acquisition was funded with proceeds from our $1 billion revolving credit facility. We have reflected the financial results of the acquired business in our supply and logistics segment from the date of the acquisition.

The following table presents selected unaudited financial information of our offshore marine transportation business included in our Unaudited Consolidated Statement of Operations for the periods presented:

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Revenues	$8,651	$8,651
Net Income	$2,520	$2,520

The table below presents selected unaudited pro forma financial information incorporating the historical results of our offshore marine transportation business. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2012 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. Depreciation expense for the fixed assets acquired is calculated on a straight-line basis over an estimated useful life of approximately 25 years.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Pro forma earnings data:				
Revenues	$1,271,201	$1,054,689	$3,663,574	$3,050,864
Net Income	$23,119	$32,812	$81,067	$69,272

3. Inventories

The major components of inventories were as follows:

	September 30, 2013	December 31, 2012
Petroleum products	$85,121	$58,943
Crude oil	26,767	15,885
Caustic soda	2,028	5,636
NaHS	5,181	6,573
Other	25	13
Total	$119,122	$87,050

Inventories are valued at the lower of cost or market. The market value of inventories was below recorded costs by approximately $0.8 million at September 30, 2013, therefore we reduced the value of inventory in our Unaudited Condensed Consolidated Financial Statements for this difference. At December 31, 2012, market values of our inventories exceeded recorded costs.

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

4. Fixed Assets
Fixed Assets
Fixed assets consisted of the following:

	September 30, 2013	December 31, 2012
Pipelines and related assets	$268,650	$226,831
Machinery and equipment	110,710	87,502
Transportation equipment	19,751	21,170
Marine vessels	529,891	298,054
Land, buildings and improvements	20,002	15,606
Office equipment, furniture and fixtures	5,436	4,964
Construction in progress	180,892	52,541
Other	20,645	16,557
Fixed assets, at cost	1,155,977	723,225
Less: Accumulated depreciation	(186,640)	(157,944)
Net fixed assets	$969,337	$565,281

Our depreciation expense for the periods presented was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Depreciation expense	$11,365	$9,202	$32,930	$27,246

5. Equity Investees
We account for our ownership in our joint ventures under the equity method of accounting. The price we pay to acquire an ownership interest in a company may exceed the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our equity investees. At September 30, 2013 and December 31, 2012, the unamortized excess cost amounts totaled $226.5 million and $234 million, respectively. We amortize the excess cost as a reduction in equity earnings in a manner similar to depreciation.

The following table presents information included in our Unaudited Condensed Consolidated Financial Statements related to our equity investees.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Genesis’ share of operating earnings	$9,641	$5,978	$24,512	$15,611
Amortization of excess purchase price	(2,582)	(2,546)	(7,894)	(7,640)
Net equity in earnings	$7,059	$3,432	$16,618	$7,971
Distributions received	$11,610	$9,045	$32,624	$27,069

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following tables present the combined unaudited balance sheet and income statement information (on a 100% basis) of our equity investees:

	September 30, 2013	December 31, 2012
BALANCE SHEET DATA:		
Assets		
Current assets	$83,886	$74,906
Fixed assets, net	1,021,106	832,525
Other assets	7,727	10,202
Total assets	$1,112,719	$917,633
Liabilities and equity		
Current liabilities	$78,979	$112,321
Other liabilities	182,210	134,731
Equity	851,530	670,581
Total liabilities and equity	$1,112,719	$917,633

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
INCOME STATEMENT DATA:				
Revenues	$49,239	$39,799	$135,507	$113,769
Operating income	$28,419	$19,810	$75,946	$53,597
Net income	$27,725	$19,196	$73,928	$51,553

6. Intangible Assets
The following table summarizes the components of our intangible assets at the dates indicated:

	September 30, 2013			December 31, 2012		
	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Refinery Services:						
Customer relationships	$94,654	$ 74,504	$20,150	$94,654	$ 69,167	$25,487
Licensing agreements	38,678	25,264	13,414	38,678	22,892	15,786
Supplier relationships	—	—	—	36,469	36,469	—
Segment total	133,332	99,768	33,564	169,801	128,528	41,273
Supply & Logistics:						
Customer relationships	35,430	28,027	7,403	35,430	26,403	9,027
Intangibles associated with lease	13,260	2,920	10,340	13,260	2,565	10,695
Trade names	—	—	—	18,888	18,888	—
Segment total	48,690	30,947	17,743	67,578	47,856	19,722
Other	20,512	6,066	14,446	18,932	4,862	14,070
Total	$202,534	$ 136,781	$65,753	$256,311	$ 181,246	$75,065

Our amortization expense for the periods presented was as follows:

	Three Months Ended September 30,	Nine Months Ended September 30,

	2013	2012	2013	2012
Amortization expense	$ 3,656	$ 4,520	$ 10,892	$ 15,390

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We estimate that our amortization expense for the next five years will be as follows:

Remainder of 2013	$3,655
2014	$12,500
2015	$10,692
2016	$9,230
2017	$8,067

7. Debt
Our obligations under debt arrangements consisted of the following:

	September 30, 2013	December 31, 2012
Senior secured credit facility	$411,300	$500,000
7.875% senior unsecured notes (including unamortized premium of $804 and $895 in 2013 and 2012, respectively)	350,804	350,895
5.750% senior unsecured notes	350,000	—
Total long-term debt	$1,112,104	$850,895

As of September 30, 2013, we were in compliance with the financial covenants contained in our credit agreement and senior unsecured notes indenture.
Senior Secured Credit Facility
At September 30, 2013, we had $411.3 million borrowed under our $1 billion credit facility, with $97.1 million of the borrowed amount designated as a loan under the inventory sublimit. The credit agreement allows up to $100 million of the capacity to be used for letters of credit, of which $15.3 million was outstanding at September 30, 2013. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date. The total amount available for borrowings under our credit facility at September 30, 2013 was $573.4 million.
Senior Unsecured Notes
In November 2010, we issued $250 million in aggregate principal amount of 7.875% senior unsecured notes due December 15, 2018 (the "2018 Notes"). The 2018 Notes were sold at face value. Interest payments are due on June 15 and December 15 of each year. In February 2012, we issued an additional $100 million of aggregate principal amount of the 2018 Notes. The additional 2018 Notes were issued at 101% of face value at an effective interest rate of 7.682%. The notes have the same terms and conditions as the notes previously issued under the indenture. The issuance increased the total aggregate principal amount of the 2018 Notes under the indenture to $350 million.
On February 8, 2013, we issued $350 million of aggregate principal amount of 5.75% senior unsecured notes (the "2021 Notes"). The 2021 Notes were sold at face value. Interest payments are due on February 15 and August 15 of each year, beginning August 15, 2013. The 2021 Notes mature on February 15, 2021. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.
The 2018 and the 2021 Notes were co-issued by Genesis Energy Finance Corporation (which has no independent assets or operations) and are each fully and unconditionally guaranteed, jointly and severally, by certain of our wholly-owned subsidiaries. We have the right to redeem the 2018 Notes at any time after December 15, 2014 at a premium to the face amount of the notes that varies based on the time remaining to maturity of the 2018 Notes. Prior to December 15, 2013, we may also redeem up to 35% of the principal amount of the 2018 Notes for 107.875% of the face amount with the proceeds from an equity offering of our common units. We have the right to redeem the 2021 Notes at any time after February 15, 2017, at a premium to the face amount of the 2021 Notes that varies based on the time remaining to maturity on the 2021 Notes. Prior to February 15, 2016, we may also redeem up to 35% of the principal amount of the 2021 Notes for 105.75% of the face amount with the proceeds from an equity offering of our common units.

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

8. Partners' Capital and Distributions
Common Units
In September 2013, we issued 5,750,000 Class A common units in a public offering at a price of $47.51 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $263.6 million from that offering. We used the net proceeds for general partnership purposes, including the repayment of outstanding borrowings under our revolving credit facility. At September 30, 2013, our outstanding common units consisted of 88,650,988 Class A units and 39,997 Class B units.
Waiver Units
Our waiver units are non-voting securities entitled to a minimal preferential quarterly distribution. At issuance, our waiver units were comprised of four classes (designated Class 1, Class 2, Class 3 and Class 4) of 1,738,000 units each. The waiver units in each class were/are convertible into Class A common units at a 1:1 conversion rate in the calendar quarter during which each of our common units receives a specified minimum quarterly distribution and our distribution coverage ratio (after giving effect to the then convertible waiver units) would be at least 1.1 times. The minimum distribution per common unit required for conversion was $0.49 for our Class 3 waiver units and is $0.52 for our Class 4 waiver units.
Our Class 1 and Class 2 waiver units converted into common units in 2012.
On May 15, 2013, our Class 3 waiver units became convertible as we paid a distribution of $0.4975 per common unit and satisfied the conversion coverage ratio requirement. All Class 3 waiver units were converted into common units by June 30, 2013.
At September 30, 2013, we had 1,738,233 waiver units outstanding comprised of the Class 4 waiver units. The Class 4 waiver units will covert into common units when we satisfy the conversion ratio requirement and pay a minimum distribution of $0.52 per common unit.
Distributions
We paid or will pay the following distributions in 2012 and 2013:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2012			
1st Quarter	May 15, 2012	$0.4500	$35,768
2nd Quarter	August 14, 2012	$0.4600	$36,563
3rd Quarter	November 14, 2012	$0.4725	$38,375
4th Quarter	February 14, 2013	$0.4850	$39,390
2013			
1st Quarter	May 15, 2013	$0.4975	$40,405
2nd Quarter	August 14, 2013	$0.5100	$42,302
3rd Quarter	November 14, 2013 (1)	$0.5225	$46,344

(1) This distribution will be paid to unitholders of record as of November 1, 2013.
9. Business Segment Information
Our operations consist of three operating segments:
- Pipeline Transportation – interstate, intrastate and offshore crude oil, and to a lesser extent, CO_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, NaHS and;
- Supply and Logistics – terminaling, blending, storing, marketing, and transporting crude oil and petroleum products (primarily fuel oil, asphalt, and other heavy refined products) and, on a smaller scale, CO_2.

Substantially all of our revenues are derived from, and substantially all of our assets are located in, the United States.

We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our stock appreciation rights plan 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 capital investment.

Segment information for the periods presented below was as follows:

	Pipeline Transportation	Refinery Services	Supply & Logistics	Total
Three Months Ended September 30, 2013				
Segment margin (a)	$29,860	$19,163	$15,801	$64,824
Capital expenditures (b)	$38,514	$632	$290,942	$330,088
Revenues:				
External customers	$16,636	$55,025	$1,188,157	$1,259,818
Intersegment (c)	6,581	(2,615)	(3,966)	—
Total revenues of reportable segments	$23,217	$52,410	$1,184,191	$1,259,818
Three Months Ended September 30, 2012				
Segment margin (a)	$23,295	$18,983	$23,651	$65,929
Capital expenditures (b)	$21,764	$1,025	$14,410	$37,199
Revenues:				
External customers	$16,190	$50,378	$975,269	$1,041,837
Intersegment (c)	2,974	(2,401)	(573)	—
Total revenues of reportable segments	$19,164	$47,977	$974,696	$1,041,837
Nine Months Ended September 30, 2013				
Segment margin (a)	$81,512	$55,824	$69,995	$207,331
Capital expenditures (b)	$159,922	$2,296	$347,001	$509,219
Revenues:				
External customers	$53,121	$161,492	$3,406,076	$3,620,689
Intersegment (c)	13,412	(8,122)	(5,290)	—
Total revenues of reportable segments	$66,533	$153,370	$3,400,786	$3,620,689
Nine Months Ended September 30, 2012				
Segment margin (a)	$69,427	$53,510	$66,075	$189,012
Capital expenditures (b)	$300,093	$2,295	$77,414	$379,802
Revenues:				
External customers	$44,564	$151,326	$2,820,095	$3,015,985
Intersegment (c)	11,230	(6,984)	(4,246)	—
Total revenues of reportable segments	$55,794	$144,342	$2,815,849	$3,015,985

Total assets by reportable segment were as follows:

	September 30, 2013	December 31, 2012
Pipeline transportation	$1,024,367	$890,652
Refinery services	414,102	414,170
Supply and logistics	1,179,791	750,347
Other assets	61,310	54,495
Total consolidated assets	$2,679,570	$2,109,664

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment Margin	$64,824	$65,929	$207,331	$189,012
Corporate general and administrative expenses	(11,113)	(9,428)	(32,255)	(26,756)
Depreciation and amortization	(16,066)	(14,838)	(46,789)	(45,447)
Interest expense	(12,587)	(9,873)	(36,282)	(30,697)
Distributable cash from equity investees in excess of equity in earnings	(5,204)	(5,613)	(16,659)	(19,098)
Non-cash items not included in segment margin	507	(2,222)	(2,828)	(2,475)
Cash payments from direct financing leases in excess of earnings	(1,291)	(1,278)	(3,786)	(3,748)
Income before income taxes	$19,070	$22,677	$68,732	$60,791

(b) Capital expenditures include maintenance and growth capital expenditures, such as fixed asset additions (including enhancements to existing facilities and construction of internal growth projects) as well as acquisitions of businesses and interests in equity investees. In addition to construction of internal growth projects, capital spending in our pipeline transportation segment included $5.2 million and $71.4 million during the three and nine months ended September 30, 2013 and $5.7 million and $57.1 million during the three and nine months ended September 30, 2012 representing capital contributions to our SEKCO equity investee to fund our share of the construction costs for its pipeline. For the three and nine months ended September 30, 2013, capital spending in our supply and logistics segment also included $230.9 million for the acquisition of our offshore marine transportation assets. For the nine months ended September 30, 2012, capital spending in our pipeline transportation segment also included $205.6 million for the acquisition of interests in several Gulf of Mexico pipelines.

(c) Intersegment sales were conducted under terms that we believe were no more or less favorable than then-existing market conditions.

10. 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues:				
Sales of CO_2 to Sandhill Group, LLC (1)	$863	$838	$2,344	$2,111
Petroleum products sales to Davison family businesses	399	326	1,043	1,012
Petroleum products sales to an affiliate of the Quintana Group (2)	—	6,376	—	21,142
Costs and expenses:				
Amounts paid to our CEO in connection with the use of his aircraft	$150	$150	$450	$450
Marine operating fuel and expenses provided by an affiliate of the Quintana Group (2)	—	1,980	—	6,181

(1) We own a 50% interest in Sandhill Group, LLC.
(2) The Quintana Group monetized all of its remaining investment in our common units on October 5, 2012. Transactions with the Quintana Group are included in the above table as related party transactions through October

5, 2012.

Amount due from Related Party

At both September 30, 2013 and December 31, 2012 Sandhill Group, LLC owed us $0.3 million for purchases of CO_2.

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11. 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,	
	2013	2012
(Increase) decrease in:		
Accounts receivable	$(92,906)	$(80,789)
Inventories	(32,073)	33,826
Other current assets	13,897	1,846
Increase (decrease) in:		
Accounts payable	75,506	57,851
Accrued liabilities	7,222	6,144
Net changes in components of operating assets and liabilities	$(28,354)	$18,878

Payments of interest and commitment fees were $32.5 million and $24.4 million for the nine months ended September 30, 2013 and September 30, 2012, respectively.

At September 30, 2013 and September 30, 2012, we had incurred liabilities for fixed and intangible asset additions totaling $22.9 million and $4.8 million, respectively, that had not been paid at the end of the third quarter, and, therefore, were not included in the caption “Payments to acquire fixed and intangible assets” under Cash Flows from Investing Activities in the Unaudited Condensed Consolidated Statements of Cash Flows.

12. Derivatives

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 of crude oil, fuel oil and petroleum products. 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 other petroleum products 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.

At September 30, 2013, we had the following outstanding derivative commodity contracts that were entered into to economically hedge inventory or fixed price purchase commitments. We had no outstanding derivative contracts that were designated as hedges under accounting rules.

	Sell (Short) Contracts	Buy (Long) Contracts
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	335	75
Weighted average contract price per bbl	$103.01	$103.47
Crude oil LLS/WTI swaps:		
Contract volumes (1,000 bbls)	110	60
Weighted average contract price per bbl	$0.09	$25.25
Diesel futures:		
Contract volumes (1,000 bbls)	39	22
Weighted average contract price per gal	$3.02	$2.97
#6 Fuel oil futures:		
Contract volumes (1,000 bbls)	898	—
Weighted average contract price per bbl	$92.81	$—
Crude oil options:		
Contract volumes (1,000 bbls)	315	95
Weighted average premium received	$1.47	$0.29
Diesel options:		
Contract volumes (1,000 bbls)	30	—
Weighted average premium received	$2.50	$—

Financial Statement Impacts

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

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The following tables reflect the estimated fair value gain (loss) position of our derivatives at September 30, 2013 and December 31, 2012:
Fair Value of Derivative Assets and Liabilities

	Unaudited Condensed Consolidated Balance Sheets Location	Fair Value September 30, 2013	December 31, 2012
Asset Derivatives:			
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$1,053	$758
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(851)	(758)
Net amount of assets presented in the Unaudited Condensed Consolidated Balance Sheets		$202	$—
Liability Derivatives:			
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(851)	$(3,357)
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other (1)	851	3,357
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets		$—	$—

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

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of September 30, 2013, we had a net broker receivable of approximately $4.9 million (consisting of initial margin of $4.6 million increased by $0.3 million of variation margin). As of December 31, 2012, we had a net broker receivable of approximately $3.6 million (consisting of initial margin of $4.1 million reduced by $0.5 million of variation margin that had been returned to us). At September 30, 2013 and December 31, 2012, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

Effect on Operating Results

	Unaudited Condensed Consolidated Statements of Operations Location	Amount of Gain (Loss) Recognized in Income			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012

Commodity derivatives - futures and call options:					
Contracts not considered hedges under accounting guidance	Supply and logistics product costs	$(4,522)	$(5,817)	$(2,877)	$(2,959)
Total commodity derivatives		$(4,522)	$(5,817)	$(2,877)	$(2,959)

13. Fair-Value Measurements

We classify financial assets and liabilities into the following three levels based on the inputs used to measure fair value:

(1) Level 1 fair values are based on observable inputs such as quoted prices in active markets for identical assets and liabilities;

(2) Level 2 fair values are based on pricing inputs other than quoted prices in active markets and are either directly or indirectly observable as of the measurement date; and

(3) Level 3 fair values are based on unobservable inputs in which little or no market data exists.

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.

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 at the dates indicated.

	Fair Value at September 30, 2013			Fair Value at December 31, 2012		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$1,053	$—	$—	$758	$—	$—
Liabilities	$(851)	$—	$—	$(3,357)	$—	$—

Our commodity derivatives include exchange-traded futures and exchange-traded options 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.

See Note 12 for additional information on our derivative instruments.

Other Fair Value Measurements

We believe the debt outstanding under our credit facility approximates fair value as the stated rate of interest approximates current market rates for similar instruments with comparable maturities. At September 30, 2013, our senior unsecured notes had a carrying value of $700.8 million and a fair value of $717.5 million, compared to $350.9 million and $373.2 million, respectively, at December 31, 2012. The fair value of the senior unsecured notes is determined based on trade information in the financial markets of our public debt and is considered a Level 2 fair value measurement.

14. Contingencies

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any 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.

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

15. Income Taxes

In the third quarter of 2012, we reversed $8.2 million of uncertain tax positions and recognized an income tax benefit in the Unaudited Condensed Consolidated Statements of Operations as a result of tax audit settlements and the expiration of statutes of limitations. These uncertain tax positions were included in Other Long-Term Liabilities in our Unaudited Condensed Consolidated Balance Sheets.

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16. Condensed Consolidating Financial Information

Our $700 million aggregate principal amount of senior unsecured notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P.'s subsidiaries, except Genesis Free State Pipeline, LLC, Genesis NEJD Pipeline, LLC and certain other minor subsidiaries. Genesis NEJD Pipeline, LLC is 100% owned by Genesis Energy, L.P., the parent company. The remaining non-guarantor subsidiaries are owned by Genesis Crude Oil, L.P., a guarantor subsidiary. Genesis Energy Finance Corporation has no independent assets or operations and accordingly has no ability to service obligations on the 2018 and 2021 Notes. Each subsidiary guarantor and the subsidiary co-issuer are 100% owned, directly or indirectly, by Genesis Energy, L.P. See Note 7 for additional information regarding our consolidated debt obligations.

The following is condensed consolidating financial information for Genesis Energy, L.P., the guarantor subsidiaries and the non-guarantor subsidiaries.

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Unaudited Condensed Consolidating Balance Sheet
September 30, 2013

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$20	$—	$15,862	$977	$—	$16,859
Other current assets	975,220	—	483,258	47,888	(999,156)	507,210
Total current assets	975,240	—	499,120	48,865	(999,156)	524,069
Fixed assets, at cost	—	—	1,039,675	116,302	—	1,155,977
Less: Accumulated depreciation	—	—	(170,629)	(16,011)	—	(186,640)
Net fixed assets	—	—	869,046	100,291	—	969,337
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	22,568	—	240,081	153,758	(160,356)	256,051
Equity investees	—	—	605,067	—	—	605,067
Investments in subsidiaries	1,252,345	—	107,042	—	(1,359,387)	—
Total assets	$2,250,153	$—	$2,645,402	$302,914	$(2,518,899)	$2,679,570
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$11,832	$—	$1,364,742	$32,820	$(999,189)	$410,205
Senior secured credit facility	411,300	—	—	—	—	411,300
Senior unsecured notes	700,804	—	—	—	—	700,804
Deferred tax liabilities	—	—	13,625	—	—	13,625
Other liabilities	—	—	13,658	163,938	(160,177)	17,419
Total liabilities	1,123,936	—	1,392,025	196,758	(1,159,366)	1,553,353
Partners' capital	1,126,217	—	1,253,377	106,156	(1,359,533)	1,126,217
Total liabilities and partners' capital	$2,250,153	$—	$2,645,402	$302,914	$(2,518,899)	$2,679,570

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Unaudited Condensed Consolidating Balance Sheet
December 31, 2012

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$10	$—	$11,214	$58	$—	$11,282
Other current assets	745,589	—	367,837	41,533	(762,207)	392,752
Total current assets	745,599	—	379,051	41,591	(762,207)	404,034
Fixed assets, at cost	—	—	617,519	105,706	—	723,225
Less: Accumulated depreciation	—	—	(144,882)	(13,062)	—	(157,944)
Net fixed assets	—	—	472,637	92,644	—	565,281
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	17,737	—	254,423	157,604	(163,696)	266,068
Equity investees	—	—	549,235	—	—	549,235
Investments in subsidiaries	1,006,415	—	102,707	—	(1,109,122)	—
Total assets	$1,769,751	$—	$2,083,099	$291,839	$(2,035,025)	$2,109,664
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$2,361	$—	$1,048,937	$23,567	$(762,214)	$312,651
Senior secured credit facility	500,000	—	—	—	—	500,000
Senior unsecured notes	350,895	—	—	—	—	350,895
Deferred tax liabilities	—	—	13,810	—	—	13,810
Other liabilities	—	—	13,044	166,282	(163,513)	15,813
Total liabilities	853,256	—	1,075,791	189,849	(925,727)	1,193,169
Partners' capital	916,495	—	1,007,308	101,990	(1,109,298)	916,495
Total liabilities and partners' capital	$1,769,751	$—	$2,083,099	$291,839	$(2,035,025)	$2,109,664

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Unaudited Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2013

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$—	$ —	$1,182,561	$ 38,908	$(37,278)	$1,184,191
Refinery services	—	—	50,609	4,199	(2,398)	52,410
Pipeline transportation services	—	—	16,604	6,613	—	23,217
Total revenues	—	—	1,249,774	49,720	(39,676)	1,259,818
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	1,165,818	39,201	(37,278)	1,167,741
Refinery services operating costs	—	—	31,840	3,862	(2,662)	33,040
Pipeline transportation operating costs	—	—	6,075	203	—	6,278
General and administrative	—	—	12,063	32	—	12,095
Depreciation and amortization	—	—	14,789	1,277	—	16,066
Total costs and expenses	—	—	1,230,585	44,575	(39,940)	1,235,220
OPERATING INCOME	—	—	19,189	5,145	264	24,598
Equity in earnings of subsidiaries	31,046	—	1,078	—	(32,124)	—
Equity in earnings of equity investees	—	—	7,059	—	—	7,059
Interest (expense) income, net	(12,572)	—	4,011	(4,026)	—	(12,587)
Income before income taxes	18,474	—	31,337	1,119	(31,860)	19,070
Income tax expense	—	—	(505)	(91)	—	(596)
NET INCOME	$18,474	$ —	$30,832	$ 1,028	$(31,860)	$18,474

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Three Months Ended September 30, 2012

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$—	$ —	$969,229	$ 31,113	$(25,646)	$974,696
Refinery services	—	—	48,809	4,367	(5,199)	47,977
Pipeline transportation services	—	—	12,596	6,568	—	19,164
Total revenues	—	—	1,030,634	42,048	(30,845)	1,041,837
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	951,512	26,488	(25,648)	952,352
Refinery services operating costs	—	—	29,339	4,565	(4,661)	29,243
Pipeline transportation operating costs	—	—	5,661	250	—	5,911
General and administrative	—	—	10,343	32	—	10,375
Depreciation and amortization	—	—	13,940	898	—	14,838
Total costs and expenses	—	—	1,010,795	32,233	(30,309)	1,012,719
OPERATING INCOME	—	—	19,839	9,815	(536)	29,118
Equity in earnings of subsidiaries	41,052	—	5,738	—	(46,790)	—
Equity in earnings of equity investees	—	—	3,432	—	—	3,432
Interest (expense) income, net	(9,858)	—	4,119	(4,134)	—	(9,873)
Income before income taxes	31,194	—	33,128	5,681	(47,326)	22,677
Income tax benefit	—	—	8,509	8	—	8,517
NET INCOME	$31,194	$ —	$41,637	$ 5,689	$(47,326)	$31,194

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	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$—	$ —	$3,387,604	$ 112,977	$(99,795)	$3,400,786
Refinery services	—	—	150,058	13,558	(10,246)	153,370
Pipeline transportation services	—	—	46,461	20,072	—	66,533
Total revenues	—	—	3,584,123	146,607	(110,041)	3,620,689
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	3,324,619	106,713	(99,795)	3,331,537
Refinery services operating costs	—	—	95,922	12,660	(10,278)	98,304
Pipeline transportation operating costs	—	—	19,497	1,010	—	20,507
General and administrative	—	—	35,064	92	—	35,156
Depreciation and amortization	—	—	43,700	3,089	—	46,789
Total costs and expenses	—	—	3,518,802	123,564	(110,073)	3,532,293
OPERATING INCOME	—	—	65,321	23,043	32	88,396
Equity in earnings of subsidiaries	104,431	—	10,849	—	(115,280)	—
Equity in earnings of equity investees	—	—	16,618	—	—	16,618
Interest (expense) income, net	(36,209)	—	12,088	(12,161)	—	(36,282)
Income before income taxes	68,222	—	104,876	10,882	(115,248)	68,732
Income tax expense	—	—	(335)	(175)	—	(510)
NET INCOME	$68,222	$ —	$104,541	$ 10,707	$(115,248)	$68,222

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Nine Months Ended September 30, 2012

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$—	$ —	$2,797,142	$ 95,451	$(76,744)	$2,815,849
Refinery services	—	—	142,716	13,756	(12,130)	144,342
Pipeline transportation services	—	—	36,381	19,413	—	55,794
Total revenues	—	—	2,976,239	128,620	(88,874)	3,015,985
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	2,743,514	83,250	(76,744)	2,750,020
Refinery services operating costs	—	—	89,155	13,701	(11,784)	91,072
Pipeline transportation operating costs	—	—	15,351	644	—	15,995
General and administrative	—	—	29,842	92	—	29,934
Depreciation and amortization	—	—	42,759	2,688	—	45,447
Total costs and expenses	—	—	2,920,621	100,375	(88,528)	2,932,468
OPERATING INCOME	—	—	55,618	28,245	(346)	83,517
Equity in earnings of subsidiaries	100,011	—	15,869	—	(115,880)	—
Equity in earnings of equity investees	—	—	7,971	—	—	7,971
Interest (expense) income, net	(30,629)	—	12,414	(12,482)	—	(30,697)
Income before income taxes	69,382	—	91,872	15,763	(116,226)	60,791
Income tax benefit (expense)	—	—	8,630	(39)	—	8,591
NET INCOME	$69,382	$ —	$100,502	$ 15,724	$(116,226)	$69,382

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Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2013

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$(139,747)	$ —	$348,447	$ 20,540	$(119,902)	$109,338
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(188,878)	(10,756)	—	(199,634)
Cash distributions received from equity investees - return of investment	8,711	—	8,272	—	(8,711)	8,272
Investments in equity investees	(263,597)	—	(71,443)	—	263,597	(71,443)
Acquisitions	—	—	(230,921)	—	—	(230,921)
Repayments on loan to non-guarantor subsidiary	—	—	3,341	—	(3,341)	—
Proceeds from asset sales	—	—	810	—	—	810
Other, net	—	—	(1,004)	—	—	(1,004)
Net cash provided by (used) in investing activities	(254,886)	—	(479,823)	(10,756)	251,545	(493,920)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,234,500	—	—	—	—	1,234,500
Repayments on senior secured credit facility	(1,323,200)	—	—	—	—	(1,323,200)
Proceeds from issuance of senior unsecured notes, including premium	350,000	—	—	—	—	350,000
Debt issuance costs	(8,157)	—	—	—	—	(8,157)
Issuance of common units for cash, net	263,597	—	263,597	—	(263,597)	263,597
Distributions to partners/owners	(122,097)	—	(122,097)	(6,545)	128,642	(122,097)
Other, net	—	—	(5,476)	(2,320)	3,312	(4,484)
Net cash provided by (used in) financing activities	394,643	—	136,024	(8,865)	(131,643)	390,159
Net (decrease) increase in cash and cash equivalents	10	—	4,648	919	—	5,577
Cash and cash equivalents at beginning of period	10	—	11,214	58	—	11,282

Cash and cash equivalents at end of period	$20	$ —	$15,862	$ 977	$—	$16,859

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

Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2012

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$(91,453)	$ —	$304,617	$ 17,700	$(87,926)	$142,938
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(112,665)	(4,037)	—	(116,702)
Cash distributions received from equity investees - return of investment	27,878	—	10,918	—	(27,878)	10,918
Investments in equity investees	(169,421)	—	(57,072)	—	169,421	(57,072)
Acquisitions	—	—	(205,576)	—	—	(205,576)
Repayments on loan to non-guarantor subsidiary	—	—	3,019	—	(3,019)	—
Proceeds from asset sales	—	—	667	—	—	667
Other, net	—	—	(1,012)	—	—	(1,012)
Net cash used in investing activities	(141,543)	—	(361,721)	(4,037)	138,524	(368,777)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,407,000	—	—	—	—	1,407,000
Repayments on senior secured credit facility	(1,333,300)	—	—	—	—	(1,333,300)
Proceeds from issuance of senior unsecured notes, including premium	101,000	—	—	—	—	101,000
Debt issuance costs	(7,109)	—	—	—	—	(7,109)
Issuance of common units for cash, net	169,421	—	169,421	—	(169,421)	169,421
Distributions to partners/owners	(104,008)	—	(104,008)	(11,819)	115,827	(104,008)
Other, net	—	—	(2,738)	(2,779)	2,996	(2,521)
Net cash provided by (used in) financing activities	233,004	—	62,675	(14,598)	(50,598)	230,483
Net increase (decrease) in cash and cash equivalents	8	—	5,571	(935)	—	4,644
Cash and cash equivalents at beginning of period	3	—	9,182	1,632	—	10,817

Cash and cash equivalents at end of period	$11	$ —	$14,753	$ 697	$—	$15,461

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

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying notes included in this Quarterly Report on Form 10-Q. The following information and such Unaudited Condensed Consolidated Financial Statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations, included in our Annual Report on Form 10-K for the year ended December 31, 2012.

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

- Overview
- Acquisition
- Financial Measures
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Forward Looking Statements

Overview

We reported net income of $18.5 million, or $0.22 per common unit during the three months ended September 30, 2013 (“2013 Quarter”) compared to net income of $31.2 million or $0.39 per common unit during the three months ended September 30, 2012 (“2012 Quarter”). The decline in net income was due to the prior year reversal of a provision for uncertain tax positions of $8.2 million combined with a $2.7 million increase in interest expense and an increase in current quarter expenses related to growth transactions of $3.1 million.

Available Cash before Reserves decreased $2.6 million, or 6%, in the 2013 Quarter (as compared to the 2012 Quarter) to $43.3 million. See “Financial Measures” below for additional information on Available Cash before Reserves.

The significant factors affecting net income and Available Cash before Reserves were a decrease in operating results from our supply and logistics segment and an increase in interest costs, partially offset by an increase in operating results from our pipeline transportation segment. Segment Margin (as described below in “Financial Measures”) decreased by $1.1 million, or 2%, in the 2013 Quarter, as compared to the 2012 Quarter. The decrease resulted primarily from a decline in Segment Margin in our supply and logistics segment of 33%, and an increase in our pipeline transportation segment of 28%. Refinery services Segment Margin was relatively constant between the quarterly periods, increasing 1%.

In the 2013 Quarter, a number of items combined to negatively impact our operating segments.

In our supply and logistics segment, operating results were negatively impacted by $6.6 million due to several items including (1) a decline in rail cars unloaded at our Walnut Hill crude-by-rail unloading terminal as a result of down-time at a connected shipper's refinery attributable to a scheduled turnaround, (2) rail car rental and storage costs incurred in advance of completion dates on certain of our rail projects, and (3) our decision to delay sales and retain on our balance sheet certain hedged refined product inventory due to a precipitous drop in the commodity margins for those products. For additional information regarding those volumes see the discussion below and in the section entitled "Liquidity and Capital Resources – Cash Flows from Operations."

In our pipeline transportation segment, operating results were adversely affected by $1.1 million due to (1) lower than expected throughput volumes on our Jay pipeline system as a result of down-time at a connected shipper's refinery attributable to a schedule turnaround, and (2) lower than expected distributions by CHOPS resulting from a 10-year right-of-way payment.

In our refinery services segment, down-time attributable to a turnaround at one of our significant refinery locations negatively impacted operating results by $0.6 million due to incremental costs incurred to meet our customers' demand.

A more detailed discussion of our segment results and other costs is included below in “Results of Operations”.

Distribution Increase

In October 2013, we declared our thirty-third consecutive increase in our quarterly distribution to our common unitholders. Twenty-eight of those quarterly increases have been 10% or greater as compared to the same quarter in the preceding year. In November 2013, we will pay a distribution of $0.5225 per unit representing a 10.6% increase from our distribution of $0.4725 per unit related to the third quarter of 2012.

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Acquisition

In August 2013, we acquired our offshore marine transportation business for approximately $230.9 million. That business is primarily comprised of nine barges and nine tug boats which transport crude oil and refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Eastern Seaboard, Great Lakes and Caribbean. At the closing of that transaction, we entered into transition services agreements to facilitate a smooth transition of operations and uninterrupted services for both employees and customers. That acquisition complements and further integrates our existing operations, including our Genesis Marine inland barge business, our crude oil and heavy refined products storage and blending terminals as well as our crude oil pipeline systems.

Financial Measures

Segment Margin

We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our stock appreciation rights plan 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 capital investment. A reconciliation of Segment Margin to income before income taxes is included in our segment disclosures in Note 9 to our Unaudited Condensed Consolidated Financial Statements. 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

This Quarterly Report on Form 10-Q 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 below provides a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure – net income. Our non-GAAP financial measure should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants.

Available Cash before Reserves, also referred to as distributable cash flow, is commonly used as a supplemental financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (1) the financial performance of our assets without regard to financing methods, capital structures, or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; (3) our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing and capital structure; and (4) the viability of projects and the overall rates of return on alternative investment opportunities. Because Available Cash before Reserves excludes some 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.

Available Cash before Reserves, including applicable pro forma presentations, is a performance measure used by our management to compare cash flows generated by us to the cash distribution paid to our common unitholders. 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 investments. Specifically, this financial measure aids investors in determining whether or not we are generating cash flows at a level that can support a quarterly cash distribution to the partners. Lastly, Available Cash before Reserves is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships.

Available Cash before Reserves is net income as adjusted for specific items, the most significant of which are the addition of certain non-cash expenses (such as depreciation and amortization), the substitution of distributable cash generated by our equity investees in lieu of our equity income attributable to our equity investees, the elimination of gains and losses on asset sales (except those from the sale of surplus assets), unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes, the elimination of expenses related to acquiring or constructing assets that provide new sources of cash flows, 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. Significant maintenance capital expenditures may be recognized over the useful life of the asset.

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Available Cash before Reserves for the periods presented below was as follows:

	Three Months Ended September 30,	
	2013	2012
	(in thousands)	
Net income	$18,474	$31,194
Depreciation and amortization	16,066	14,838
Cash received from direct financing leases not included in income	1,291	1,278
Cash effects of sales of certain assets	184	13
Effects of distributable cash generated by equity method investees not included in income	5,204	5,613
Cash effects of legacy stock appreciation rights plan	(470)	(466)
Non-cash legacy stock appreciation rights plan (benefit) expense	(181)	2,001
Expenses related to acquiring or constructing assets that provide new sources of cash flow	3,326	228
Unrealized gain on derivative transactions excluding fair value hedges	(779)	(75)
Maintenance capital expenditures	(610)	(701)
Non-cash tax expense (benefit)	350	(8,717)
Other items, net	414	653
Available Cash before Reserves	$43,269	$45,859

Results of Operations

Revenues and Costs and Expenses

Our revenues for the 2013 Quarter increased $218 million, or 21% from the 2012 Quarter. Additionally, our costs and expenses increased $222.5 million, or 22% between the two periods.

Our revenues for the nine months ended September 30, 2013 increased $604.7 million, or 20% from the nine months ended September 30, 2012. Costs and expenses increased $599.8 million, or 20% between the nine month periods.

The substantial majority of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products. The significant increase in our revenues and costs between the two third quarter and nine month periods is primarily attributable to increased volumes from our operations and increases in the market prices for crude oil and petroleum products as described below.

Volumes increased in our supply and logistics segment by 16% quarter to quarter and 25% between the nine month periods as explained in our supply and logistics Segment Margin discussion below. The average closing prices for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX") increased 15% to $105.83 per barrel in the third quarter of 2013, as compared to $92.22 per barrel in the third quarter of 2012. Average closing prices for WTI crude oil on the NYMEX increased 2% from $96.21 per barrel in the first nine months of 2012 to $98.14 per barrel in the first nine months of 2013.

Segment Margin

The contribution of each of our segments to total Segment Margin in the three and nine months ended September 30, 2013 and September 30, 2012 was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)		(in thousands)	
Pipeline transportation	$29,860	$23,295	$81,512	$69,427
Refinery services	19,163	18,983	55,824	53,510
Supply and logistics	15,801	23,651	69,995	66,075
Total Segment Margin	$64,824	$65,929	$207,331	$189,012

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We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment Margin	$64,824	$65,929	$207,331	$189,012
Corporate general and administrative expenses	(11,113)	(9,428)	(32,255)	(26,756)
Depreciation and amortization	(16,066)	(14,838)	(46,789)	(45,447)
Interest expense	(12,587)	(9,873)	(36,282)	(30,697)
Distributable cash from equity investees in excess of equity in earnings	(5,204)	(5,613)	(16,659)	(19,098)
Non-cash items not included in segment margin	507	(2,222)	(2,828)	(2,475)
Cash payments from direct financing leases in excess of earnings	(1,291)	(1,278)	(3,786)	(3,748)
Income before income taxes	$19,070	$22,677	$68,732	$60,791

Our reconciliation of Segment Margin to income before income taxes reflects that Segment Margin (as defined above) excludes corporate general and administrative expenses, depreciation and amortization, interest expense, certain non-cash items, the most significant of which are the non-cash effects of our stock appreciation rights plan and unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. Items in Segment Margin not included in income before income taxes are distributable cash from equity investees in excess of equity in earnings (or losses) and cash payments from direct financing leases in excess of earnings.

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Pipeline Transportation Segment

Operating results and volumetric data for our pipeline transportation segment are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases - onshore crude oil pipelines	$10,667	$8,297	$30,071	$22,400
Segment margin from offshore crude oil pipelines, including pro-rata share of distributable cash from equity investees	11,776	8,927	31,489	27,114
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	6,703	6,662	20,457	19,700
Sales of onshore crude oil pipeline loss allowance volumes	3,650	2,369	9,292	7,152
Onshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(4,455)	(4,461)	(14,320)	(11,384)
Payments received under direct financing leases not included in income	1,291	1,278	3,786	3,748
Other	228	223	737	697
Segment Margin	$29,860	$23,295	$81,512	$69,427
Volumetric Data (barrels/day unless otherwise noted):				
Onshore crude oil pipelines:				
Texas	52,557	52,767	53,629	50,327
Jay	39,808	22,841	35,365	19,931
Mississippi	17,768	17,942	18,561	18,377
Offshore crude oil pipelines:				
CHOPS (1)	160,105	91,377	133,868	78,817
Poseidon (1)	203,909	215,474	209,713	206,596
Odyssey (1)	45,073	31,869	44,254	35,994
GOPL	8,138	8,300	8,797	16,979
CO_2 pipeline (Mcf/day):				
Free State	201,635	188,165	212,381	177,527

(1) Volumes for our equity method investees are presented on a 100% basis.

Three Months Ended September 30, 2013 Compared with Three Months Ended September 30, 2012

Pipeline transportation Segment Margin for the 2013 Quarter increased $6.6 million, or 28% even though operating results were adversely affected by $1.1 million due to (1) lower than expected throughput volumes on our Jay pipeline system as a result of down-time at a connected shipper's refinery attributable to a scheduled turnaround, and (2) lower than expected distributions by CHOPS resulting from a 10-year right-of-way payment. However, these events were more than offset by overall increases in volumes from our Jay pipeline system and distributions from CHOPS as further discussed below.

Other significant components and details of this change were as follows:

- With respect to our onshore crude oil pipelines, tariff revenues increased $2.4 million primarily due to (1) upward tariff indexing of approximately 4.6% for our FERC-regulated pipelines effective in July 2013 and (2)a net increase in throughput volumes of 16,583 barrels (18%) per day, primarily from our Jay pipeline system. Our Jay pipeline system volumes increased primarily from additional barrels received at our crude-by-rail unloading terminal at Walnut Hill, Florida, partially offset by lower than expected throughput volumes due to down-time at a connected shipper's refinery attributable to a scheduled turnaround.
- Segment Margin from our offshore crude oil pipelines increased $2.8 million, primarily reflecting an increased contribution from CHOPS. In the 2012 Quarter, improvement facility work by producers at the connected production

fields resulted in lower volumes transported on CHOPS. The positive impact to Segment Margin from increased volumes by CHOPS was partially offset by a 10-year right-of-way payment.

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- Onshore crude oil pipeline loss allowance volumes, collected and sold, increased Segment Margin by $1.3 million due to an increase in barrels transported in the 2013 Quarter as compared to the 2012 Quarter.
- Volumes on our Free State CO_2 pipeline system increased 13,470 Mcf per day, or 7%, in the 2013 Quarter as compared to the 2012 Quarter. We provide transportation services on our Free State CO_2 pipeline system through an “incentive” tariff which provides that the average rate per Mcf that we charge during any month decreases as our aggregate throughput for that month increases above specific thresholds. As a result of this "incentive" tariff, increases in volumes on our Free State CO_2 pipeline system have a limited impact on Segment Margin.

Nine Months Ended September 30, 2013 Compared with Nine Months Ended September 30, 2012

Pipeline transportation Segment Margin for the nine month periods increased $12.1 million, or 17%, even though operating results were adversely affected by $3.6 million due to (1) lower than expected throughput volumes on our Jay pipeline system as a result of down-time at a connected shipper's refinery attributable to a scheduled turnaround, (2) lower than expected distributions by CHOPS resulting from a 10-year right-of-way payment, (3) production variations at connected offshore fields, and (4) unplanned downtime on the Eugene Island System. However, these events were more than offset by overall increases in volumes primarily from our Jay pipeline system and increased distributions from CHOPS as further discussed below.

Other significant components and details of this change were as follows:

- With respect to our onshore crude oil pipelines, tariff revenues increased $7.7 million primarily due to (1) upward tariff indexing of approximately 4.6% for our FERC-regulated pipelines effective in July 2013 and (2) a net increase in throughput volumes of 18,920 barrels (21%) per day, primarily from our Jay pipeline system. Our Jay pipeline system volumes increased primarily from additional barrels received at our crude-by-rail unloading terminal at Walnut Hill, Florida, partially offset by lower than expected throughput volumes due to down-time at a connected shipper's refinery attributable to a scheduled turnaround.
- Segment Margin from our offshore crude oil pipelines increased $4.4 million, primarily reflecting an increased contribution from CHOPS. In the first nine months of 2012, improvement facility work by producers at the connected production fields resulted in lower volumes transported on CHOPS. The positive impact to Segment Margin from increased volumes by CHOPS was partially offset by (1) a 10-year right-of-way payment, (2) production variations at connected offshore fields, and (3) unplanned downtime on the Eugene Island System.
- Onshore crude oil pipeline loss allowance volumes, collected and sold, increased Segment Margin by $2.1 million due to an increase in barrels transported in the first nine months of 2013 as compared to the first nine months of 2012.
- Onshore pipeline operating costs, excluding non-cash charges, increased $2.9 million due to required five-year integrity testing expenditures on our onshore pipelines, employee compensation and related benefit costs and general increases in operating costs inclusive of increased safety program costs.
- Volumes on our Free State CO_2 pipeline system increased 34,854 Mcf per day, or 20%, in the first nine months of 2013 as compared to the first nine months of 2012. We provide transportation services on our Free State CO_2 pipeline system through an “incentive” tariff which provides that the average rate per Mcf that we charge during any month decreases as our aggregate throughput for that month increases above specific thresholds. As a result of this "incentive" tariff, increases in volumes on our Free State CO_2 pipeline system have a limited impact on Segment Margin.

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Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Volumes sold (in Dry short tons "DST"):				
NaHS volumes	35,946	34,372	109,233	107,321
NaOH (caustic soda) volumes	24,492	21,152	65,442	56,740
Total	60,438	55,524	174,675	164,061
Revenues (in thousands):				
NaHS revenues	$38,493	$36,903	$117,790	$113,937
NaOH (caustic soda) revenues	14,454	11,936	38,551	32,211
Other revenues	2,078	1,539	5,151	5,178
Total external segment revenues	$55,025	$50,378	$161,492	$151,326
Segment Margin (in thousands)	$19,163	$18,983	$55,824	$53,510
Average index price for NaOH per DST [1]	$606	$579	$611	$566
Raw material and processing costs as % of segment revenues	52 %	46 %	50 %	48 %

(1) Source: IHS Chemical

Three Months Ended September 30, 2013 Compared with Three Months Ended September 30, 2012

Refinery services Segment Margin for the 2013 Quarter increased $0.2 million, or 1%. In the 2013 Quarter, Segment Margin increased primarily due to increased NaHS sales volumes that were substantially offset by $0.6 million of additional costs incurred to meet our customers' demand due to down-time attributable to a turnaround at one of our significant refinery locations.

Other significant components of this fluctuation were as follows:

- NaHS revenues increased primarily as a function of the increase in the average index price for caustic soda (which is a component of our sales price) and increased sales volumes, partially offset by the other components referenced below. The pricing in our sales contracts for NaHS includes adjustments for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments are applied varies by contract, geographic region and supply point. The mix of NaHS sales volumes to which these adjustments applied reduced NaHS revenues in the 2013 Quarter.
- Our raw material costs related to NaHS increased correspondingly to the rise in the average index price for caustic soda, although we were able to partially offset our increased raw materials costs with operating efficiencies at several of our sour gas processing facilities, our favorable management of the acquisition (including economies of scale) and utilization of caustic soda in our (and our customers') operations, and our logistics management capabilities.
- Caustic soda sales volumes increased 16%. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. Consequently, we are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively purchase additional caustic soda for re-sale to third parties. Our ability to purchase caustic soda volumes is currently sufficient to meet the demands of our refinery services operations and third-party sales.
- Average index prices for caustic soda increased to $606 per DST in the third quarter of 2013 compared to $579 per DST during the third quarter of 2012. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we

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usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic soda on our operating costs.

Nine Months Ended September 30, 2013 Compared with Nine Months Ended September 30, 2012

Refinery services Segment Margin increased $2.3 million, or 4%, between the nine month periods. During that period, we experienced increased Segment Margin attributable primarily to increased NaHS sales volumes that were partially offset by $0.6 million of additional costs incurred to meet customers' demand due to down-time attributable to a turnaround at one of our significant refinery locations.

Other significant components of this fluctuation were as follows:

- NaHS revenues increased primarily as a function of increased sales volumes and an increase in the average index price for caustic soda (which is a component of our sales price), partially offset by other components referenced below. In the first nine months of 2013, NaHS sales volumes increased primarily due to increased demand from customers in the pulp and paper industry, however this increase was partially offset by a decrease in sales to South American customers (due to timing of bulk deliveries). The pricing in our sales contracts for NaHS includes adjustments for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments are applied varies by contract, geographic region and supply point. The mix of NaHS sales volumes to which these adjustments applied reduced NaHS revenues in the first nine months of 2013.
- Our raw material costs related to NaHS increased correspondingly to the rise in the average index price for caustic soda, although we were able to partially offset our increased raw materials costs with operating efficiencies at several of our sour gas processing facilities, our favorable management of the acquisition (including economies of scale) and utilization of caustic soda in our (and our customers') operations, and our logistics management capabilities.
- Caustic soda sales volumes increased 15%. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. Consequently, we are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively purchase additional caustic soda for re-sale to third parties. Our ability to purchase caustic soda volumes is currently sufficient to meet the demands of our refinery services operations and third-party sales.
- Average index prices for caustic soda increased to $611 per DST in the first nine months of 2013 compared to $566 per DST during the first nine months of 2012. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic soda on our operating costs.

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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,	
	2013	2012	2013	2012
	(in thousands)		(in thousands)	
Supply and logistics revenue	$1,184,191	$974,696	$3,400,786	$2,815,849
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(1,117,650)	(911,474)	(3,188,105)	(2,631,695)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(50,845)	(39,927)	(143,417)	(117,846)
Other	105	356	731	(233)
Segment Margin	$15,801	$23,651	$69,995	$66,075
Volumes of crude oil and petroleum products (barrels per day)	116,277	100,095	114,470	91,444

The average market prices of crude oil and petroleum products increased 15% and 2% between the three and nine month periods, respectively, however that price volatility has a limited impact on our Segment Margin.

Three Months Ended September 30, 2013 Compared with Three Months Ended September 30, 2012

Segment Margin for our supply and logistics segment decreased by $7.9 million, or 33% between the two third quarter periods. In the 2013 Quarter, our operating results were negatively impacted by $6.6 million for several discrete items including (1) a decline in rail cars unloaded at our Walnut Hill crude-by-rail unloading terminal as a result of down-time at a connected shipper's refinery attributable to a scheduled turnaround, (2) rail car rental and storage costs incurred in advance of completion dates on certain of our rail projects, and (3) our decision to delay sales and retain on our balance sheet certain hedged refined product inventory due to a precipitous drop in the commodity margins for those products. Although we had hedged that refined product inventory (as well as all of our other product inventory), we believe we ultimately will be able to normalize the margin we make on those refined product volumes by waiting for the related commodity margins and recognized realized hedge losses given our decision to delay sales, to correct to more normal levels/correlations. Our decisions, from time to time, to carry more or less product inventory than usual are often driven by dislocations in the prices/margins for the underlying commodities.

Crude and petroleum products volumes increased 16% in the 2013 Quarter, however our operating costs, excluding non-cash charges, increased 27% between the two third quarters primarily due to employee compensation and related benefit costs. Increases in those costs are the result of a higher number of employees from our expanded marine and trucking fleets and the recent growth in our crude oil rail loading and unloading operations.

The overall decrease in Segment Margin was partially offset due to the recent acquisition of our offshore marine transportation business and the contribution from our crude oil rail loading and unloading operations completed in the second half of 2012.

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Nine Months Ended September 30, 2013 Compared with Nine Months Ended September 30, 2012

Segment Margin for our supply and logistics segment increased by $3.9 million, or 6%, during the first nine months of 2013. In the 2013 nine month period, our operating results were negatively impacted by $9.5 million for several items including (1) a decline in rail cars unloaded at our Walnut Hill crude-by-rail unloading terminal as a result of down-time at a connected shipper's refinery attributable to a scheduled turnaround, (2) rail car rental and storage costs incurred in advance of completion dates on certain of our rail projects, (3) our decision to delay sales and retain on our balance sheet certain hedged refined product inventory due to a precipitous drop in the commodity margins for those products, all as more particularly described above, (4) expenses for repairs to one of our marine vessels as well as foregone Segment Margin attributable to that vessel's downtime, (5) demurrage costs incurred due to damage to a river lock caused by a third party operator that idled certain of our barge activities during a shipment of petroleum products, (6) downtime as a result of a turnaround at our crude processing facility in Wyoming, (7) ineffectiveness of hedging certain crude oil volumes, and (8) volumetric measurement losses associated with our crude oil gathering and marketing activities. However, the negative impacts above were more than offset by the factors discussed below.

Crude and petroleum products volumes increased 25% during the first nine months of 2013, however our operating costs, excluding non-cash charges, increased 22% between the two nine month periods primarily due to employee compensation and related benefit costs. Increases in those costs are the result of a higher number of employees from our expanded marine and trucking fleets and the recent growth in our crude oil rail loading and unloading operations.

Segment Margin also increased due to the recent acquisition of our offshore marine transportation business and the contribution from our crude oil rail loading and unloading operations completed in the second half of 2012.

Other Costs, Interest, and Income Taxes

General and administrative expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below:				
Corporate	$6,141	$7,615	$20,977	$21,764
Segment	982	905	2,782	3,016
Equity-based compensation plan expense	1,646	1,627	7,188	4,138
Third party costs related to business development activities and growth projects	3,326	228	4,209	1,016
Total general and administrative expenses	$12,095	$10,375	$35,156	$29,934

Total general and administrative expenses increased $1.7 million and $5.2 million between the three and nine month periods, respectively, primarily due to increases in third party costs related to business and growth transactions. General and administrative expenses also increased between the nine month periods due to an increase in equity-based compensation plan expenses not included in Segment Margin. Increases in the market price of our common units resulted in increased expenses related to our equity-based compensation plans. The market price of our common units at September 30, 2013 was $50.07 compared to $35.72 at December 31, 2012, representing a 40% increase.

Depreciation and amortization expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)		(in thousands)	
Depreciation expense	$11,365	$9,202	$32,930	$27,246
Amortization of intangible assets	3,656	4,520	10,892	15,390
Amortization of CO_2 volumetric production payments	1,045	1,116	2,967	2,811
Total depreciation and amortization expense	$16,066	$14,838	$46,789	$45,447

Total depreciation and amortization expense increased $1.2 million and $1.3 million, between the quarterly and nine month periods, respectively, as a result of increases in depreciation expense resulting primarily from a gradually increasing asset

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base, partially offset by decreases in amortization of intangible assets. Depreciation expense increased $2.2 million and $5.7 million between the three and nine month periods, respectively, primarily as a result of the acquisition of our offshore marine transportation assets and recently completed internal growth projects. Amortization of intangible assets decreased $0.9 million and $4.5 million between the three and nine month periods, respectively, as we amortize our intangible assets over the period in which we expect them to contribute to our future cash flows.

Interest expense, net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)		(in thousands)	
Interest expense, credit facility (including commitment fees)	$3,196	$3,414	$8,416	$10,748
Interest expense, senior unsecured notes	11,982	6,938	33,697	19,688
Amortization of debt issuance costs and premium	1,046	825	3,234	2,655
Capitalized interest	(3,637)	(1,304)	(9,065)	(2,394)
Net interest expense	$12,587	$9,873	$36,282	$30,697

Net interest expense increased $2.7 million between the quarterly periods and $5.6 million between the nine month periods. In February 2013, we issued an additional $350 million of aggregate principal amount of 5.75% senior unsecured notes to repay borrowings under our senior secured credit facility. Capitalized interest costs, which increased $2.3 million and $6.7 million in the three and nine month periods, respectively, due to our growth capital expenditures and investments in the SEKCO pipeline joint venture (see below for more information), partially offset the increase in interest expense.

Income tax expense

A portion of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. As a result, a substantial portion of the income tax expense we record relates to the operations of those corporations, and will vary from period to period as a percentage of our income before taxes based on the percentage of our income or loss that is derived from those corporations. The balance of the income tax expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles and foreign income taxes.

Income tax expense increased $9.1 million between the quarterly and nine month periods primarily due to the reversal of $8.2 million in uncertain tax positions as a result of tax audit settlements and the expiration of statutes of limitations in the third quarter of 2012.

Other

Net income for the three months ended September 30, 2013 included an unrealized gain on derivative positions of $0.8 million. Net income for the same period in 2012 included an unrealized gain on derivative positions of $0.1 million. Net income for the nine months ended September 30, 2013 and 2012 included an unrealized gain on derivative positions of $2.8 million and $1.3 million, respectively. Those amounts are included in supply and logistics product costs in the Unaudited Condensed Consolidated Statements of Operations and are not a component of Segment Margin.

Liquidity and Capital Resources

General

As of September 30, 2013, we had $573.4 million of borrowing capacity available under our $1 billion senior secured revolving credit facility. We anticipate that our future internally-generated funds and the funds available under our credit facility will allow us to meet our ordinary course capital needs. Our primary sources of liquidity have been cash flows from operations, borrowing availability under our credit facility and the proceeds from issuances of equity and senior notes.

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Our primary cash requirements consist of:

- Working capital, primarily inventories;
- Routine operating expenses;
- Capital expansion and maintenance projects;
- Acquisitions of assets or businesses;
- Interest payments related to outstanding debt; and
- Quarterly cash distributions to our unitholders.

Capital Resources

Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital from time to time — including through equity and debt offerings (public and private), borrowings under our credit facility and other financing transactions—and to implement our growth strategy successfully. No assurance can be made that we will be able to raise necessary funds on satisfactory terms.

In September 2013, we issued 5,750,000 Class A common units in a public offering at a price of $47.51 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $263.6 million from the offering. We used the net proceeds for general corporate purposes, including the repayment of borrowings under our revolving credit facility. See Note 8 to our Unaudited Condensed Consolidated Financial Statements for more information.

Our $1 billion senior secured credit facility matures on July 25, 2017 and includes an accordion feature of $300 million, giving us the ability to expand the size of the facility up to an aggregate of $1.3 billion for acquisitions or internal growth projects, subject to lender consent. The inventory financing sublimit tranche under our senior secured credit facility is $150 million, which is designed to allow us to more efficiently finance crude oil and petroleum products inventory in the normal course of our operations, by allowing us to exclude the amount of inventory loans from our total outstanding indebtedness for purposes of determining our applicable interest rate. Our credit facility does not include a "borrowing base" limitation except with respect to our inventory loans. Our credit facility allows up to $100 million of the capacity to be used for letters of credit, of which $15.3 million was outstanding at September 30, 2013. Due to the revolving nature of loans under our credit facility, we may make additional borrowings and periodic repayments and re-borrowings until the maturity date. At September 30, 2013, we had $411.3 million borrowed under our credit facility, with $97.1 million of the borrowed amount designated as a loan under the inventory sublimit. Thus, the total amount available for borrowings under our credit facility at September 30, 2013 was $573.4 million.

On February 8, 2013, we issued an additional $350 million of aggregate principal amount of 5.75% senior unsecured notes. The notes were sold at face value. Interest payments are due on February 15 and August 15 of each year, beginning August 15, 2013. The notes mature on February 15, 2021. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.

The notes were co-issued by Genesis Energy Finance Corporation (which has no independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly-owned subsidiaries. We have the right to redeem the notes at any time after February 15, 2017, at a premium to the face amount of the notes that varies based on the time remaining to maturity on the notes. Prior to February 15, 2016, we may also redeem up to 35% of the principal amount for 105.750% of the face amount with the proceeds from an equity offering of our common units.

At September 30, 2013, long-term debt totaled $1.1 billion, consisting of $411.3 million outstanding under our credit facility (including $97.1 million borrowed under the inventory sublimit tranche), a $350.8 million carrying amount of senior unsecured notes due on December 15, 2018 and a $350 million carrying amount of senior unsecured notes due on February 15, 2021.

Cash Flows from Operations

We generally 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 facility and to fund capital expenditures. Our operating cash flows can be impacted by changes in items of working capital, primarily variances in the carrying amount of inventory and the timing of payment of accounts payable and accrued liabilities related to capital expenditures.

We typically sell our crude oil in the same month in which we purchase it, and we do not rely on borrowings under our credit facility to pay for such crude oil purchases, other than inventory. During such periods, our accounts receivable and accounts payable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil.

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In our petroleum products activities, we buy products and typically either move the products to one of our storage facilities for further blending or we sell the product within days of our purchase. The cash requirements for these activities can result in short term increases and decreases in our borrowings under our credit facility.

The storage of crude oil and petroleum products can have a material impact on our cash flows from operating activities. In the month we pay for the stored crude oil or petroleum products, we borrow under our credit facility (or use cash on hand) to pay for the crude oil or petroleum products, utilizing a portion of our operating cash flows. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil or petroleum products. Additionally, we may be required to deposit margin funds with the NYMEX when prices increase as the value of the derivatives utilized to hedge the price risk in our inventory fluctuates. These deposits also impact our operating cash flows as we borrow under our credit facility or use cash on hand to fund the deposits. On September 30, 2013, our inventory was $32.1 million higher than it was on December 31, 2012. That increased inventory level primarily related to our decision to delay sales and retain on our balance sheet certain hedged refined product inventory due to a precipitous drop in the commodity margins for those products. Although we had hedged that refined product inventory (as well as all of our other product inventory), we believe we ultimately will be able to normalize the margin we make on those refined product volumes by waiting for the related commodity margins and recognized realized hedge losses given our decision to delay sales, to correct to more normal levels/correlations. Our decisions, from time to time, to carry more or less product inventory than usual are often driven by dislocations in the prices/margins for the underlying commodities.

See Note 11 in our Unaudited Condensed Consolidated Financial Statements for information regarding changes in components of operating assets and liabilities for the nine months ended September 30, 2013 and September 30, 2012.

Net cash flows provided by our operating activities for the nine months ended September 30, 2013 were $109.3 million compared to $142.9 million for the nine months ended September 30, 2012. As discussed above, changes in the cash requirements related to payment for petroleum products or collection of receivables from the sale of inventory impact the cash provided by operating activities. Additionally, changes in the market prices for crude oil and petroleum products can result in fluctuations in our operating cash flows between periods as the cost to acquire a barrel of oil or petroleum products will require more or less cash. The decrease in operating cash flow for the nine months ended September 30, 2013 compared to the same period in 2012 was primarily due to increases in cash requirements to meet working capital needs and lower cash earnings.

Capital Expenditures and Distributions Paid to our Unitholders

We use cash primarily for our operating expenses, working capital needs, debt service, acquisition activities, internal growth projects and distributions we pay to our unitholders. We finance smaller internal growth projects and distributions primarily with cash generated by our operations. Acquisition activities and large internal growth projects have historically been funded with borrowings under our credit facility, equity issuances and/or the issuance of senior unsecured notes.

Capital Expenditures and Business and Asset Acquisitions

A summary of our expenditures for fixed assets, business and other asset acquisitions for the nine months ended September 30, 2013 and September 30, 2012 is as follows:

	Nine Months Ended September 30, 2013	2012
	(in thousands)	
Capital expenditures for fixed and intangible assets:		
Pipeline transportation assets	$88,479	$37,445
Refinery services assets	2,296	2,295
Supply and logistics assets	116,080	77,414
Information technology systems	1,581	1,175
Total capital expenditures for fixed and intangible assets	208,436	118,329
Capital expenditures for business combinations, net of liabilities assumed:		
Acquisition of offshore marine transportation assets	230,921	—

Offshore pipelines [1]	—	205,576
Total business combinations capital expenditures	230,921	205,576
Capital expenditures related to equity investees [2]	71,443	57,072
Total capital expenditures	$510,800	$380,977

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(1) In 2012, amount represents the investment to acquire interests in several Gulf of Mexico crude oil pipeline systems.
(2) Amounts represent our investment in the SEKCO pipeline joint venture (see below for more information).
Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital. We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows.

Capital Expenditures for Acquisition

On August 28, 2013, we completed the acquisition of our offshore marine transportation assets, consisting of nine barges and nine tug boats for approximately $230.9 million.

Growth Capital Expenditures

Total capital expenditures on projects currently under construction, and disclosed in the following discussion, are estimated to be approximately $700 million, inclusive of capital expenditures incurred in prior quarters. We anticipate that approximately $425 million of that total will be spent in 2013.

Gulf Coast Infrastructure

We are improving existing assets and developing new infrastructure in Louisiana, including connecting to Exxon Mobil Corporation's Baton Rouge refinery, one of the largest refinery complexes in North America, with more than 500,000 barrels per day of refining capacity. Our investment includes improving our existing terminal at Port Hudson, Louisiana, constructing a new 18-mile 20-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Scenic Station and continuing downstream to the Anchorage Tank Farm and building a new crude oil unit train unload facility at Scenic Station. The Port Hudson upgrades and new crude oil pipeline are expected to be completed in early 2014, and Scenic Station completion is scheduled for the second quarter of 2014.

Texas City Project

We completed construction on an 18-inch diameter loop of our existing Texas crude oil pipeline into Texas City in the third quarter of 2013, supported by a term contract with one of our refining customers, which we expect will allow us to significantly expand our total service capabilities into the Texas City area , with full commercial operations beginning by the end of 2013.

HollyFrontier Tulsa Project

We are installing a new sour gas processing facility at Holly Refining and Marketing's refinery complex located in Tulsa, Oklahoma. The new facility, which was substantially completed late in the third quarter of 2013, will remove a portion of the sulfur from the crude oil refined at Holly's complex and is expected to result in potential additional capacity of 24,000 DST per year of NaHS.

Rail Projects

Walnut Hill - In the first quarter of 2013, we completed construction on the second phase of our crude-by-rail unloading terminal at Walnut Hill, Florida, which includes a 100,000 barrel storage tank and related equipment. This facility is capable of handling unit train shipments of oil for direct deliveries to an existing refinery customer and indirect deliveries (through third-party common carriers) to multiple other markets in the Southeast at the option of the shippers. The unit trains of crude oil received at Walnut Hill, Florida will be inserted downstream for further delivery on our Jay Pipeline System. We have commenced construction on an additional tank at the site with 110,000 barrels of capacity, which will allow us to handle increased rail traffic and higher throughput on our existing connected Jay crude oil pipeline. We estimate this tank will be fully operational at the end of the fourth quarter of 2013.

Wink - In 2012, we completed the initial phase construction of a crude oil rail loading facility in Wink, Texas, designed to move crude oil from West Texas to other markets and giving us the capability to load Genesis and third party railcars. Construction on the second phase of the facility, which we estimate will be operational in the fourth quarter of 2013, will allow us to increase the capacity of this rail loading facility.

Natchez - In the third quarter of 2013, we completed construction on a crude oil rail unloading/loading facility at our existing terminal located in Natchez, Mississippi, which is designed to facilitate the movement of Canadian bitumen/dilbit to Gulf Coast markets. That facility will have the capability to unload bitumen/dilbit as well as load diluent for backhauls to Canada. We have initiated construction on the second phase of the Natchez facility, which will provide an additional 60 railcar spots and additional heated tanks, and anticipate this rail unloading/loading facility expansion to be fully operational in late 2013.

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Pronghorn - In the second quarter of 2013, we began construction on a new unit train loading facility in the Powder River Basin of the Niobrara Shale Play. The facility will be tied-in to our existing gathering system in the region and is expected to be fully operational in late 2013.

Raceland - In the fourth quarter of 2013, we began construction on a new crude oil unit train unloading facility capable of unloading up to two unit trains per day, located in Raceland, Louisiana. The Raceland Rail Facility will be connected to existing midstream infrastructure that will provide direct pipeline access to both St. James and Baton Rouge area refineries and is expected to be operational in the third quarter of 2014.

Wyoming Gathering Project

In the second quarter of 2013, we completed the re-activation of portions of the related gathering and transportation pipelines in Wyoming and construction of a new pipeline which connects to the Casper, Wyoming markets.

Capital Expenditures Related to Equity Investees

SEKCO, a joint venture with Enterprise Products, is constructing a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. The new pipeline is expected to begin service by mid-2014. We have budgeted approximately $200 million for our cumulative share of the pipeline construction through 2014. In 2012, we contributed $63.7 million to SEKCO that was used to fund our share of the construction costs incurred during the year. We have budgeted approximately $125 million in 2013, of which we have paid $71.4 million during the first nine months of 2013. Most cost overruns and other costs incurred associated with weather-related delays will be the responsibility of the producers that have entered into transportation agreements with us.

Distributions to Unitholders

On November 14, 2013, we will pay a distribution of $0.5225 per common unit totaling $46.3 million with respect to the third quarter of 2013 to common unitholders of record on November 1, 2013. This is the thirty-third consecutive quarter in which we have increased our quarterly distribution. Information on our recent distribution history is included in Note 8 to our Unaudited Condensed Consolidated Financial Statements.

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, 2012.

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, 2012, nor do we have any debt or equity triggers based upon our unit or commodity prices.

Forward Looking Statements

The statements in this Quarterly Report on Form 10-Q that are not historical information may be “forward looking statements” as defined under federal law. 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, and historical performance is not necessarily indicative of future performance. 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,” “goal,” “intend,” “may,” “could,” “plan,” “position,” “projection,” “strategy,” “should” or “will,” or the n 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, among others:

- demand for, the supply of, our assumptions about, changes in forecast data for, and price trends related to crude oil, liquid petroleum, NaHS, caustic soda and CO_2, all of which may be affected by economic activity,

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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 close strategic acquisitions on acceptable terms (including obtaining third-party consents and waivers of preferential rights), develop or construct energy infrastructure assets, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- service interruptions in our pipeline transportation systems and processing operations;
- shutdowns or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, petroleum or other products or to whom we sell such products;
- risks inherent in marine transportation and vessel operation, including accidents and discharge of pollutants;
- changes in laws and regulations to which we are subject, including tax withholding issues, accounting pronouncements, and safety, environmental and employment laws and regulations;
- the effects of production declines resulting from the suspension of drilling in the Gulf of Mexico and the effects of future laws and government regulation resulting from the Macondo accident and oil spill in the Gulf;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of our credit agreement and the indenture governing our notes, which contain various affirmative and negative covenants;
- loss of key personnel;
- an increase in the competition that our operations encounter;
- cost and availability of insurance;
- hazards and operating risks that may not be covered fully by insurance;
- our financial and commodity hedging arrangements;
- changes in global economic conditions, including capital and credit markets conditions, inflation and interest rates;
- natural disasters, accidents or terrorism;
- changes in the financial condition of customers or counterparties;
- adverse rulings, judgments, or settlements in litigation or other legal or tax matters;
- the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes; and
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price.

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, 2012. These risks may also be specifically described in our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Form 8-K/A and other documents that we may file from time to time with the SEC. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2012. There have been no material changes that would affect the quantitative and qualitative disclosures provided therein. Also, see Note 12 to our Unaudited Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

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

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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 on Form 10-Q is accumulated and communicated to them and our management to allow timely decisions regarding required disclosures.
There were no changes during the period covered by this report that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings
Information with respect to this item has been incorporated by reference from our Annual Report on Form 10-K for the year ended December 31, 2012. There have been no material developments in legal proceedings since the filing of such Form 10-K.

Item 1A. Risk Factors
There has been no material change in our risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012, except as supplemented by our Quarterly Reports on Form 10-Q and Periodic Reports on Form 8-K. For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2012, as well as any risk factors contained in other filings with the SEC, including Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Form 8-K/A and other documents that we may file from time to time with the SEC.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None.

Item 3. Defaults Upon Senior Securities
None.

Item 4. Mine Safety Disclosures
Not applicable.

Item 5. Other Information
None.

Item 6. Exhibits.
(a) Exhibits

	3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 to Registration Statement on Form S-1, File No. 333-11545).
	3.2	Amendment to the Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.2 to Form 10-Q for the quarterly period ended June 30, 2011, File No. 011-12295).
	3.3	Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 3, 2011, File No. 001-12295).
	3.4	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, File No. 001-12295).
	3.5	Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011, File No. 001-12295).
	3.6	Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011, File No. 001-12295).
	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, File No. 001-12295).
*	10.1	First Amendment to Third Amended and Restated Credit Agreement dated August 12, 2013, among Genesis Energy, L.P. as borrower, Wells Fargo Bank, National Association, as

administrative agent, Bank of America N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto.

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*	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.
*	101.INS	XBRL Instance Document
*	101.SCH	XBRL Schema Document
*	101.CAL	XBRL Calculation Linkbase Document
*	101.LAB	XBRL Label Linkbase Document
*	101.PRE	XBRL Presentation Linkbase Document
*	101.DEF	XBRL Definition Linkbase Document

* Filed herewith

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SIGNATURES

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

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)

By: GENESIS ENERGY, LLC,
as General Partner

Date: November 1, 2013

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