MARTIN MIDSTREAM PARTNERS LP
Form 10-Q
August 05, 2009

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

FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2009

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________ to ____________

Commission File Number
000-50056
MARTIN MIDSTREAM PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	**05-0527861**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

4200 Stone Road
Kilgore, Texas 75662
(Address of principal executive offices, zip code)
Registrant s telephone number, including area code: **(903) 983-6200**

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicated by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The number of the registrant s Common Units outstanding at August 5, 2009 was 13,688,152. The number of the registrant s subordinated units outstanding at August 5, 2009 was 850,674.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED BALANCE SHEETS
(Dollars in thousands)

	June 30, 2009 (Unaudited)	December 31, 2008 (Audited)
Assets		
Cash	$ 9,573	$ 7,983
Accounts and other receivables, less allowance for doubtful accounts of $754 and $481	53,425	68,117
Product exchange receivables	7,603	6,924
Inventories	34,563	42,461
Due from affiliates	7,003	555
Fair value of derivatives	2,470	3,623
Other current assets	834	1,079
Total current assets	115,471	130,742
Property, plant, and equipment, at cost	532,206	537,381
Accumulated depreciation	(138,783)	(125,256)
Property, plant and equipment, net	393,423	412,125
Goodwill	37,268	37,405
Investment in unconsolidated entities	80,613	79,843
Fair value of derivatives	487	1,469
Other assets, net	6,219	7,332
	$ 633,481	$ 668,916
Liabilities and Capital		
Trade and other accounts payable	$ 58,483	$ 87,382
Product exchange payables	17,388	10,924
Due to affiliates	11,765	13,420
Income taxes payable	414	414
Fair value of derivatives	8,156	6,478
Other accrued liabilities	3,108	6,077
Total current liabilities	99,314	124,695
Long-term debt	297,200	295,000

Deferred income taxes	8,324	8,538
Fair value of derivatives	1,961	4,302
Other long-term obligations	1,471	1,667
Total liabilities	408,270	434,202
Partners capital	228,744	239,649
Accumulated other comprehensive loss	(3,533)	(4,935)
Total partners capital	225,211	234,714
Commitments and contingencies		
	$ 633,481	$ 668,916

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)
(Dollars in thousands, except per unit amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues:				
Terminalling and storage	$ 9,982	$ 9,900	$ 19,581	$ 17,820
Marine transportation	15,101	19,309	31,437	35,712
Product sales:				
Natural gas services	74,822	182,025	165,688	389,117
Sulfur services	19,343	86,027	45,929	156,252
Terminalling and storage	9,020	10,882	22,539	22,258
	103,185	278,934	234,156	567,627
Total revenues	128,268	308,143	285,174	621,159
Costs and expenses:				
Cost of products sold:				
Natural gas services	69,668	180,324	152,335	383,174
Sulfur services	8,591	75,964	27,026	132,304
Terminalling and storage	7,918	10,270	20,023	20,191
	86,177	266,558	199,384	535,669
Expenses:				
Operating expenses	23,519	26,195	47,407	50,412
Selling, general and administrative	4,087	3,467	8,266	6,946
Depreciation and amortization	8,511	7,614	16,916	14,954
Total costs and expenses	122,294	303,834	271,973	607,981
Other operating income (loss)	5,073	(14)	5,073	126
Operating income	11,047	4,295	18,274	13,304
Other income (expense):				
Equity in earnings of unconsolidated entities	1,028	4,372	3,088	7,882
Interest expense	(4,183)	(3,895)	(8,852)	(8,638)
Other, net	49	67	71	247
Total other income (expense)	(3,106)	544	(5,693)	(509)
Net income before taxes	7,941	4,839	12,581	12,795
Income tax benefit (expense)	(16)	(522)	214	(461)

Net income	$ 7,925	$ 4,317	$ 12,795	$ 12,334
General partner s interest in net income	$ 868	$ 665	$ 1,675	$ 1,316
Limited partners interest in net income	$ 7,057	$ 3,652	$ 11,120	$ 11,018
Net income per limited partner unit basic and diluted	$ 0.49	$ 0.25	$ 0.76	$ 0.76
Weighted average limited partner units basic	14,532,826	14,532,826	14,532,826	14,532,826
Weighted average limited partner units diluted	14,537,737	14,535,779	14,537,119	14,535,564

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF CAPITAL
(Unaudited)
(Dollars in thousands)

	Partners Capital						
	Common		Subordinated		General Partner	Accumulated Other Comprehensive Income (Loss)	
	Units	Amount	Units	Amount	Amount	Amount	Total
Balances January 1, 2008	12,837,480	$ 244,520	1,701,346	$ (6,022)	$ 4,112	$ (6,762)	$ 235,848
Net income		9,958		1,060	1,316		12,334
Cash distributions		(18,229)		(2,416)	(1,535)		(22,180)
Unit-based compensation		34					34
Adjustment in fair value of derivatives						(9,539)	(9,539)
Balances June 30, 2008	12,837,480	$ 236,283	1,701,346	$ (7,378)	$ 3,893	$ (16,301)	$ 216,497
Balances January 1, 2009	13,688,152	$ 239,333	850,674	$ (3,688)		$ 4,004	(4,935) $ $234,714
Net income		10,470		650	1,675		12,795
Cash distributions		(20,532)		(1,276)	(1,923)		(23,731)
Unit-based compensation		31					31
Adjustment in fair value of derivatives						1,402	1,402
Balances June 30, 2009	13,688,152	$ 229,302	850,674	$ (4,314)	$ 3,756	$ (3,533)	$ 225,211

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(Dollars in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net income	$ 7,925	$ 4,317	$ 12,795	$ 12,334
Changes in fair values of commodity cash flow hedges	(431)	(8,700)	(12)	(8,487)
Commodity cash flow hedging gains (losses) reclassified to earnings	(648)	41	(1,345)	(624)
Changes in fair value of interest rate cash flow hedges	(317)	4,112	(940)	(428)
Interest rate cash flow hedging gains reclassified to earnings	1,926		3,699	
Comprehensive income	$ 8,455	$ (230)	$ 14,197	$ 2,795

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)
(Dollars in thousands)

	Six Months Ended June 30,	
	2009	**2008**
Cash flows from operating activities:		
Net income	$ 12,795	$ 12,334
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	16,916	14,954
Amortization of deferred debt issuance costs	562	559
Deferred taxes	(214)	(155)
Gain on sale of property, plant and equipment	(5,073)	(126)
Equity in earnings of unconsolidated entities	(3,088)	(7,882)
Distributions from unconsolidated entities	650	
Distributions in-kind from equity investments	2,316	5,621
Non-cash mark-to-market on derivatives	2,874	5,195
Other	31	34
Change in current assets and liabilities, excluding effects of acquisitions and dispositions:		
Accounts and other receivables	14,661	(22,959)
Product exchange receivables	(679)	(31,236)
Inventories	7,898	(50,034)
Due from affiliates	(2,392)	(6,011)
Other current assets	245	(6,509)
Trade and other accounts payable	(29,099)	64,546
Product exchange payables	6,464	46,302
Due to affiliates	7,789	2,595
Income taxes payable		69
Other accrued liabilities	(2,969)	(34)
Change in other non-current assets and liabilities	(100)	(224)
Net cash provided by operating activities	29,587	27,039
Cash flows from investing activities:		
Payments for property, plant and equipment	(25,428)	(52,756)
Acquisitions, net of cash acquired		(5,983)
Proceeds from sale of property, plant and equipment	19,610	404
Return of investments from unconsolidated entities	380	600
Distributions from (contributions to) unconsolidated entities for operations	(1,028)	75
Net cash used in investing activities	(6,466)	(57,660)
Cash flows from financing activities:		

Payments of long-term debt	(56,900)	(100,791)
Proceeds from long-term debt	59,100	160,770
Payments of debt issuance costs		(18)
Cash distributions paid	(23,731)	(22,180)
Net cash provided by (used in) financing activities	(21,531)	37,781
Net increase in cash	1,590	7,160
Cash at beginning of period	7,983	4,113
Cash at end of period	$ 9,573	$ 11,273

See accompanying notes to consolidated and condensed financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2009
(Unaudited)

(1) General

Martin Midstream Partners L.P. (the Partnership) is a publicly traded limited partnership with a diverse set of operations focused primarily in the United States Gulf Coast region. Its four primary business lines include: terminalling and storage services for petroleum products and by-products, natural gas services, marine transportation services for petroleum products and by-products, and sulfur and sulfur based products processing, manufacturing, marketing and distribution.

The Partnership s unaudited consolidated and condensed financial statements have been prepared in accordance with the requirements of Form 10-Q and U.S. generally accepted accounting principles for interim financial reporting. Accordingly, these financial statements have been condensed and do not include all of the information and footnotes required by generally accepted accounting principles for annual audited financial statements of the type contained in the Partnership s annual reports on Form 10-K. In the opinion of the management of the Partnership s general partner, all adjustments and elimination of significant intercompany balances necessary for a fair presentation of the Partnership s results of operations, financial position and cash flows for the periods shown have been made. All such adjustments are of a normal recurring nature. Results for such interim periods are not necessarily indicative of the results of operations for the full year. These financial statements should be read in conjunction with the Partnership s audited consolidated financial statements and notes thereto included in the Partnership s annual report on Form 10-K for the year ended December 31, 2008 filed with the Securities and Exchange Commission (the SEC) on March 4, 2009.

(a) Use of Estimates

Management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with U.S. generally accepted accounting principles. Actual results could differ from those estimates.

(b) Unit Grants

The Partnership issued 1,000 restricted common units to each of its three independent, non-employee directors under its long-term incentive plan in May 2008 from treasury units purchased by the Partnership in the open market for $93. These units vest in 25% increments beginning in January 2009 and will be fully vested in January 2012.

The Partnership issued 1,000 restricted common units to each of its three independent, non-employee directors under its long-term incentive plan in May 2007. These units vest in 25% increments beginning in January 2008 and will be fully vested in January 2011.

The Partnership issued 1,000 restricted common units to each of its three independent, non-employee directors under its long-term incentive plan in January 2006. These units vest in 25% increments on the anniversary of the grant date each year and will be fully vested in January 2010.

The Partnership accounts for the transactions under *Emerging Issues Task Force 96-18 Accounting for Equity Instruments That are Issued to other than Employees for Acquiring, or in Conjunction with Selling, Goods or Services.* The cost resulting from the share-based payment transactions was $12 and $17 for the three months ended June 30, 2009 and 2008, respectively, and $31 and $34 for the six months ended June 30, 2009 and 2008, respectively. The Partnership s general partner contributed cash of $2 in January 2006 and $3 in May 2007 to the Partnership in conjunction with the issuance of these restricted units in order to maintain its 2% general partner interest in the Partnership. The Partnership s general partner did not make a contribution attributable to the restricted units issued to its three independent, non-employee directors in May 2008, as such units were purchased in the open market by the Partnership for $93.

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(c) Incentive Distribution Rights

The Partnership s general partner, Martin Midstream GP LLC, holds a 2% general partner interest and certain incentive distribution rights (IDRs) in the Partnership. IDRs are a separate class of non-voting limited partner interest that may be transferred or sold by the general partner under the terms of the partnership agreement, and represent the right to receive an increasing percentage of cash distributions after the minimum quarterly distribution and any cumulative arrearages on common units once certain target distribution levels have been achieved. The Partnership is required to distribute all of its available cash from operating surplus, as defined in the partnership agreement. The target distribution levels entitle the general partner to receive 2% of quarterly cash distributions up to $0.55 per unit, 15% of quarterly cash distributions in excess of $0.55 per unit until all unitholders have received $0.625 per unit, 25% of quarterly cash distributions in excess of $0.625 per unit until all unitholders have received $0.75 per unit, and 50% of quarterly cash distributions in excess of $0.75 per unit. For the three months ended June 30, 2009 and 2008 the general partner received $724 and $590, respectively, in incentive distributions. For the six months ended June 30, 2009 and 2008 the general partner received $1,448 and $1,091, respectively, in incentive distributions.

(d) Net Income per Unit

In March 2008, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) issued EITF 07-4, Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share*, to Master Limited Partnerships (EITF 07-4). EITF 07-4 addresses the application of the two-class method under SFAS No. 128 Earnings Per Share in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions accounted for as equity distributions. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions for the period are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years.

The Partnership adopted EITF 07-04 on January 1, 2009. Adoption did not impact the Partnership s computation of earnings per limited partner unit as cash distributions exceeded earnings for the three months and six months ended June 30, 2009 and 2008, and the IDRs do not share in losses under the partnership agreement. In the event the Partnership s earnings exceed cash distributions, EITF 07-04 will have an impact on the computation of the Partnership s earnings per limited partner unit. The Partnership agreement does not explicitly limit distributions to the general partner; therefore, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the Partnership agreement. For the three and six months ended June 30, 2009 and 2008, the general partner s interest in net income, including the IDRs, represents distributions declared after period end on behalf of the general partner interest and IDRs less the allocated excess of distributions over earnings for the periods.

The following table reconciles net income to limited partners interest in net income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Net income	$ 7,925	$ 4,317	$ 12,795	$ 12,334
Less:				

Distributions payable on behalf of IDRs	(724)	(590)	(1,448)	(1,091)
Distributions payable on behalf of general partner interest	(237)	(222)	(574)	(444)
Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	93	147	347	219
Limited partners interest in net income	$ 7,057	$ 3,652	$ 11,120	$ 11,018

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The weighted average units outstanding for basic net income per unit were 14,532,826 for both the three and six months ended June 30, 2009 and 2008. For diluted net income per unit, the weighted average units outstanding were increased by 4,911 and 2,953 for the three months ended June 30, 2009 and 2008, respectively, and 4,293 and 2,738 for the six months ended June 30, 2008 and 2007, respectively, due to the dilutive effect of restricted units granted under the Partnership s long-term incentive plan.

(e) Income taxes

With respect to the Partnership s taxable subsidiary (Woodlawn Pipeline Co., Inc.), income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

(2) New Accounting Pronouncements

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (SFAS 165), to be effective for interim or annual financial periods ending after June 15, 2009. SFAS 165 does not materially change the existing guidance but introduces the concept of financial statements being available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. This disclosure is intended to alert all users of financial statements that an entity has not evaluated subsequent events after that date in the set of financial statements being presented. SFAS 165 became effective for the Partnership on April 1, 2009 and the adoption did not have an impact on its financial statements. The Partnership has evaluated subsequent events through August 5, 2009, which is the date of the filing of its quarterly report on Form 10-Q.

In April 2009, the FASB issued FASB Staff Position FAS 157-4, Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions that are not Orderly (FSP FAS 157-4), which is effective for the Partnership for the quarterly period beginning April 1, 2009. FSP FAS 157-4 affirms that the objective of fair value when the market for an asset is not active is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date under current market conditions. FSP FAS 157-4 provides guidance for estimating fair value when the volume and level of market activity for an asset or liability have significantly decreased and determining whether a transaction was orderly. FSP FAS 157-4 applies to all fair value measurements when appropriate. The Partnership adopted FSP FAS 157-4 effective April 1, 2009.

In April 2009, the FASB issued FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP FAS 107-1), which is effective for the Partnership for the quarterly period beginning April 1, 2009. FSP FAS 107-1 requires an entity to provide the annual disclosures required by FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments, in its interim consolidated financial statements. The Partnership adopted FSP FAS 107-1 effective April 1, 2009.

In April 2009, the FASB issued FASB Staff Position FAS 141(R)-1, Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies (FSP FAS 141(R)-1). This pronouncement amends FAS No. 141-R to clarify the initial and subsequent recognition, subsequent accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. FSP FAS No. 141(R)-1 requires that assets acquired and liabilities assumed in a business combination that

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(Dollars in thousands, except where otherwise indicated)
June 30, 2009
(Unaudited)

arise from contingencies be recognized at fair value, as determined in accordance with SFAS No. 157, if the acquisition-date fair value can be reasonably estimated. If the acquisition-date fair value of an asset or liability cannot be reasonably estimated, the asset or liability would be measured at the amount that would be recognized in accordance with FASB Statement No. 5, Accounting for Contingencies (SFAS No. 5), and FASB Interpretation No. 14, Reasonable Estimation of the Amount of a Loss. FSP FAS No. 141(R)-1 became effective for the Partnership as of January 1, 2009. As the provisions of FSP FAS 141(R)-1 are applied prospectively to business combinations with an acquisition date on or after the guidance became effective, the impact to the Partnership cannot be determined until the transactions occur. No such transactions occurred during 2009.

In March 2008, the EITF issued EITF 07-4. EITF 07-4 addresses the application of the two-class method under SFAS No. 128 Earnings Per Share in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The Partnership adopted EITF 07-04 on January 1, 2009. See Note 1 (d) for more information.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of SFAS No. 133 (SFAS No. 161). SFAS No. 161 requires enhanced disclosures about an entity s derivative and hedging activities and was effective for the Partnership on January 1, 2009. Since SFAS No. 161 requires enhanced disclosures concerning derivatives and hedging activities (see Note 7 for disclosures related to the adoption of SFAS 161), the adoption of SFAS 161 effective January 1, 2009 did not affect the consolidated financial position, results of operations or cash flows of the Partnership.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 establishes new accounting, disclosure and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 was effective for the Partnership on January 1, 2009. The adoption of SFAS No. 160 had no impact on the Partnership s consolidated financial statements. However, it could impact accounting for future transactions.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) retains the underlying concepts of SFAS No. 141 in that all business combinations are still required to be accounted for at fair value under the acquisition method of accounting, but SFAS No. 141(R) establishes revised principles and requirements for how entities will recognize and measure assets and liabilities acquired in a business combination, including but not limited to, generally expensing of acquisition costs as incurred and valuing noncontrolling interests (minority interests) at fair value at the acquisition date. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141(R) will impact all acquisitions closed on or after January 1, 2009.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157), which is intended to increase consistency and comparability in fair value measurements by defining fair value, establishing a framework for measuring fair value, and expanding disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. The Partnership adopted SFAS 157 as of January 1, 2008, with the exception of the application of the statement to non-recurring nonfinancial assets and nonfinancial liabilities, which was delayed to fiscal years beginning after November 15, 2008, which The Partnership therefore adopted as of January 1, 2009. As of June 30, 2009, the Partnership does not have any significant non-recurring measurements of nonfinancial assets and nonfinancial liabilities. See Note 3 Fair Value Measurements for further information.

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NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
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June 30, 2009
(Unaudited)

Accounting Standards Not Yet Adopted.

In June 2009, the FASB issued SFAS No. 167, Amendments to FASB Interpretation No. 46(R) (SFAS 167), which amends the consolidation guidance applicable to variable interest entities under FASB Interpretation No. 46 (R), Consolidation of Variable Interest Entities . SFAS 167 is intended to improve financial reporting by enterprises involved with variable interest entities. This guidance is effective as of the beginning of the first fiscal year that begins after November 15, 2009. The Partnership is currently assessing the impact SFAS 167 will have on its financial statements.

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (SFAS 168), which amends SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles . SFAS 168 will become the source of authoritative U.S. GAAP recognized by the FASB to be applied by non-governmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. On the effective date, SFAS 168 will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in SFAS 168 will become non-authoritative. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Partnership is currently assessing the impact SFAS 168 will have on its financial statements.

(3) Fair Value Measurements

During the first quarter of 2008, the Partnership adopted SFAS 157. SFAS 157 established a framework for measuring fair value and expanded disclosures about fair value measurements. The adoption of SFAS 157 had no impact on the Partnership s financial position or results of operations.

SFAS 157 applies to all assets and liabilities that are being measured and reported on a fair value basis. This statement enables the reader of the financial statements to assess the inputs used to develop those measurements by establishing a hierarchy for ranking the quality and reliability of the information used to determine fair values. SFAS 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value of each asset and liability carried at fair value into one of the following categories:

Level 1: Quoted market prices in active markets for identical assets or liabilities.
Level 2: Observable market based inputs or unobservable inputs that are corroborated by market data.
Level 3: Unobservable inputs that are not corroborated by market data.

The Partnership s derivative instruments which consist of commodity and interest rate swaps are required to be measured at fair value on a recurring basis. The fair value of the Partnership s derivative instruments is determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets, which is considered Level 2. Refer to Notes 7, 8 and 9 for further information on the Partnership s derivative instruments and hedging activities.

The following items are measured at fair value on a recurring basis subject to the disclosure requirements of SFAS 157 at June 30, 2009:

	Fair Value Measurements at Reporting Date Using		
	Quoted Prices in Active Markets for for	Significant Other Observable	Significant Unobservable

Description	June 30, 2009	Identical Assets (Level 1)	Inputs (Level 2)	Inputs (Level 3)
Assets				
Interest rate derivatives	$ 1,117	$	$ 1,117	$
Commodity derivatives	1,840		1,840	
Total assets	$ 2,957	$	$ 2,957	$

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		Fair Value Measurements at Reporting Date Using		
Description	June 30, 2009	Quoted Prices in Active Markets for for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities				
Interest rate derivatives	$ (9,856)	$	$ (9,856)	$
Commodity derivatives	(261)		(261)	
Total liabilities	$ (10,117)	$	$ (10,117)	$

The following items are measured at fair value on a recurring basis subject to the disclosure requirements of SFAS 157 at December 31, 2008:

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2008	Quoted Prices in Active Markets for for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Commodity derivatives	$ 5,092	$	$ 5,092	$

Liabilities				
Interest rate derivatives	$ (10,780)	$	$ (10,780)	$

During the second quarter of 2009, the Partnership adopted FASB Staff Position No. FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments . This staff position amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments , to require disclosures about the fair value of financial instruments of publicly-traded companies for interim reporting periods as well as in annual financial statements. This staff position also amends APB Opinion No. 28, Interim Financial Reporting , to require the aforementioned disclosures in summarized financial information at interim reporting periods. The basis for fair value estimates are set forth below for the Partnership s financial instruments.

The following methods and assumptions were used to estimate the fair value of each class of financial instrument:

Accounts and other receivables, trade and other accounts payable, other accrued liabilities, income taxes payable and due from/to affiliates The carrying amounts approximate fair value because of the short maturity of these instruments.

Long-term debt including current installments The carrying amount of the revolving and term loan facilities approximates fair value due to the debt having a variable interest rate.

(4) Acquisitions

Stanolind Assets In January 2008, the Partnership acquired 7.8 acres of land, a deep water dock and two sulfuric acid tanks at its Stanolind terminal in Beaumont, Texas from Martin Resource Management

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for $5,983 which was allocated to property, plant and equipment. Martin Resource Management entered into a lease agreement with the Partnership for use of the sulfuric acid tanks. In connection with the acquisition, the Partnership borrowed approximately $6,000 under its credit facility.

(5) Inventories

Components of inventories at June 30, 2009 and December 31, 2008 were as follows:

	2009	2008
Natural gas liquids	$ 16,256	$ 10,530
Sulfur	449	6,522
Sulfur based products	12,218	14,879
Lubricants	3,065	8,110
Other	2,575	2,420
	$ 34,563	$ 42,461

(6) Investments in Unconsolidated Partnerships and Joint Ventures

The Partnership s Prism Gas Systems I, L.P. (Prism Gas) subsidiary owns an unconsolidated 50% interest in Waskom Gas Processing Company (Waskom), the Matagorda Offshore Gathering System (Matagorda), and the Panther Interstate Pipeline Energy LLC (PIPE). As a result, these assets are accounted for by the equity method.

On June 30, 2006, the Partnership s Prism Gas subsidiary, acquired a 20% ownership interest in a partnership which owns the lease rights to the assets of the Bosque County Pipeline (BCP). The lease contract terminated in June 2009 and as such the investment was fully amortized as of June 30, 2009. This interest is accounted for by the equity method of accounting.

In accounting for the acquisition of the interests in Waskom, Matagorda and PIPE, the carrying amount of these investments exceeded the underlying net assets by approximately $46,176. The difference was attributable to property and equipment of $11,872 and equity method goodwill of $34,304. The excess investment relating to property and equipment is being amortized over an average life of 20 years, which approximates the useful life of the underlying assets. Such amortization amounted to $148 and $297 for the three and six months ended June 30, 2009 and 2008, respectively, and has been recorded as a reduction of equity in earnings of unconsolidated entities. The remaining unamortized excess investment relating to property and equipment was $9,795 and $10,092 at June 30, 2009 and December 31, 2008, respectively. The equity-method goodwill is not amortized in accordance with SFAS 142; however, it is analyzed for impairment annually or if changes in circumstance indicate that a potential impairment exists. No impairment was recognized for the six months ended June 30, 2009 or 2008.

As a partner in Waskom, the Partnership receives distributions in kind of natural gas liquids (NGLs) that are retained according to Waskom s contracts with certain producers. The NGLs are valued at prevailing market prices. In addition, cash distributions are received and cash contributions are made to fund operating and capital requirements of Waskom.

Activity related to these investment accounts for the six months ended June 30, 2009 and 2008 is as follows:

	Waskom	PIPE	Matagorda	BCP	Total
Investment in unconsolidated entities, December 31, 2008	$ 74,978	$ 1,214	$ 3,559	$ 92	$ 79,843
Distributions in kind	(2,316)				(2,316)
Distributions from unconsolidated entities	(650)				(650)
Contributions to unconsolidated entities:					
Cash contributions		90			90
Contributions to unconsolidated entities for operations	938				938
Return of investments		(145)	(235)		(380)
Equity in earnings:					
Equity in earnings (losses) from operations	2,993	388	96	(92)	3,385
Amortization of excess investment	(275)	(8)	(14)		(297)
Investment in unconsolidated entities, June 30, 2009	$ 75,668	$ 1,539	$ 3,406	$	$ 80,613

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	Waskom	PIPE	Matagorda	BCP	Total
Investment in unconsolidated entities, December 31, 2007	$ 70,237	$ 1,582	$ 3,693	$ 178	$ 75,690
Distributions in kind	(5,621)				(5,621)
Contributions to (distributions from) unconsolidated entities:					
Cash contributions	500			80	580
Contributions to (distributions from) unconsolidated entities for operations	(655)				(655)
Return of investments	(300)	(105)	(195)		(600)
Equity in earnings:					
Equity in earnings from operations	7,875	84	302	(82)	8,179
Amortization of excess investment	(275)	(8)	(14)		(297)
Investment in unconsolidated entities, June 30, 2008	$ 71,761	$ 1,553	$ 3,786	$ 176	$ 77,276

Select financial information for significant unconsolidated equity method investees is as follows:

	As of June 30		Three Months Ended June 30		Six Months Ended June 30	
	Total Assets	Partner s Capital	Revenues	Net Income	Revenues	Net Income
2009						
Waskom	$ 78,162	$ 69,659	$ 12,188	$ 2,046	$ 27,618	$ 5,985
	As of December 31					
2008						
Waskom	$ 78,661	$ 67,730	$ 35,807	$ 8,468	$ 62,540	$ 15,748

As of June 30, 2009 and December 31, 2008, the Partnership s interest in cash of the unconsolidated equity method investees was $1,131 and $1,956, respectively.

(7) Risk Management and Financial Instruments

In March 2008, the FASB issued SFAS 161 which changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The

Partnership adopted SFAS 161 on January 1, 2009.

Derivative Financial Instruments

The Partnership s results of operations are materially impacted by changes in crude oil, natural gas and natural gas liquids prices and interest rates. In an effort to manage the Partnership s exposure to these risks, the Partnership periodically enters into various derivative instruments, including commodity and interest rate hedges. In accordance with SFAS 133, the Partnership is required to recognize all derivative instruments as either assets or liabilities at fair value on our Consolidated Balance Sheets and to recognize

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certain changes in the fair value of derivative instruments on the Partnership s Consolidated Statements of Operations.

The Partnership performs, at least quarterly, both a prospective and retrospective assessment of the effectiveness of our hedge contracts, including assessing the possibility of counterparty default. If it is determined that a derivative is no longer expected to be highly effective, the Partnership discontinues hedge accounting prospectively and recognizes subsequent changes in the fair value of the hedge in earnings.

Cash flow hedges

For derivative instruments that are designated and qualify as cash flow hedges under SFAS 133, the effective portion of the gain or loss on the derivative is reported as a component of accumulated other comprehensive income and reclassified into earnings in the same period during which the hedged transaction affects earnings. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in fair value of the hedged item. To the extent the change in the fair value of the hedge does not perfectly offset the change in the fair value of the hedged item, the ineffective portion of the hedge is immediately recognized in earnings.

The following table summarizes the fair values and classification of the Partnership s derivative instruments in its Condensed and Consolidated Balance Sheet:

Fair Values of Derivative Instruments in the Consolidated Balance Sheet

	Derivative Assets			Derivative Liabilities		
		Fair Values			Fair Values	
	Balance Sheet Location	June 30, 2009	December 31, 2008	Balance Sheet Location	June 30, 2009	December 31, 2008
Derivatives designated as hedging instruments under Statement 133:						
	Current:			Current:		
Interest rate contracts	Fair value of derivatives	$	$	Fair value of derivatives	$ 937	$ 5,427
Commodity contracts	Fair value of derivatives	1,328	2,430	Fair value of derivatives		
		1,328	2,430		937	5,427
	Non-current:			Non-current:		
Interest rate contracts	Fair value of derivatives	150		Fair value of derivatives		4,050
Commodity contracts	Fair value of derivatives	169	716	Fair value of derivatives		

			319		716				4,050
Total derivatives designated as hedging instruments under Statement 133		$	1,647	$	3,146		$	937	$	9,477
Derivatives not designated as hedging instruments under Statement 133:									
	Current:					Current:			
Interest rate contracts	Fair value of derivatives	$	963	$		Fair value of derivatives	$	7,092	$	1,051
Commodity contracts	Fair value of derivatives		179		1,193	Fair value of derivatives		127		
			1,142		1,193			7,219		1,051

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Fair Values of Derivative Instruments in the Consolidated Balance Sheet

	Derivative Assets			Derivative Liabilities		
		Fair Values			Fair Values	
	Balance Sheet Location	June 30, 2009	December 31, 2008	Balance Sheet Location	June 30, 2009	December 31, 2008
	Non-current:			Non-current:		
Interest rate contracts	Fair value of derivatives	4		Fair value of derivatives	1,827	252
Commodity contracts	Fair value of derivatives	164	753	Fair value of derivatives	134	
		168	753		1,961	252
Total derivatives not designated as hedging instruments under Statement 133		$ 1,310	$ 1,946		$ 9,180	$ 1,303

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Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Six Months Ended June 30, 2009 and 2008

	Effective Portion					Ineffective Portion and Amount Excluded from Effectiveness Testing		
	Amount of Gain or (Loss) Recognized in OCI on Derivatives		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income		Location of Gain or (Loss) Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
	2009	2008		2009	2008		2009	2008
Derivatives designated as hedging instruments under Statement 133								
Interest rate contracts	$ (317)	$ 4,112	Interest Expense	$ (1,926)	$	Interest Expense	$	$
Commodity contracts	(431)	(8,700)	Natural Gas Revenues	648	43	Natural Gas Revenues		(84)
Total derivatives designated as hedging instruments under Statement 133	$ (748)	$ (4,588)		$ (1,278)	$ 43		$	$ (84)

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
		2009	2008
Derivatives not designated as hedging instruments under Statement 133			
Interest rate contracts	Interest Expense	$ (57)	$ (193)

Commodity contracts	Natural Gas Services Revenues	(1,606)	(6,008)
Total derivatives not designated as hedging instruments under Statement 133		$ (1,663)	$ (6,201)

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Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Six Months Ended June 30, 2009 and 2008

	Amount of Gain or (Loss) Recognized in OCI on Derivatives		Effective Portion: Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income		Ineffective Portion and Amount Excluded from Effectiveness Testing: Location of Gain or (Loss) Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
	2009	2008		2009	2008		2009	2008
Derivatives designated as hedging instruments under Statement 133								
Interest rate contracts	$ (940)	$ (428)	Interest Expense	$ (3,699)	$	Interest Expense	$	$
Commodity contracts	(12)	(8,487)	Natural Gas Revenues	1,366	587	Natural Gas Revenues	(21)	37
Total derivatives designated as hedging instruments under Statement 133	$ (952)	$ (8,915)		$ (2,333)	$ 587		$ (21)	$ 37

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives 2009	2008
Derivatives not designated as hedging instruments under Statement 133			
Interest rate contracts	Interest Expense	$ (207)	$ (966)
Commodity contracts	Natural Gas Services Revenues	(1,355)	(8,733)

Total derivatives not designated as hedging instruments under Statement 133	$ (1,562)	$ (9,699)

Amounts expected to be reclassified into earnings for the subsequent twelve month period are losses of $2,430 for interest rate cash flow hedges and gains of $1,521 for commodity cash flow hedges. See notes 8 and 9 for further discussion of the Partnership s commodity and interest rate hedging activities.

(8) Commodity Cash Flow Hedges

The Partnership is exposed to market risks associated with commodity prices, counterparty credit and interest rates. The Partnership has established a hedging policy and monitors and manages the commodity market risk associated with its commodity risk exposure. In addition, the Partnership is focused

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on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

The Partnership uses derivatives to manage the risk of commodity price fluctuations**.** Additionally, the Partnership manages interest rate exposure by targeting a ratio of fixed and floating interest rates it deems prudent and using hedges to attain that ratio.

In accordance with SFAS 133, all derivatives and hedging instruments are included on the balance sheet as an asset or a liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in accumulated other comprehensive income (AOCI) until such time as the hedged item is recognized in earnings. The Partnership is exposed to the risk that periodic changes in the fair value of derivatives qualifying for hedge accounting will not be effective, as defined, or that derivatives will no longer qualify for hedge accounting. To the extent that the periodic changes in the fair value of the derivatives are not effective, that ineffectiveness is recorded to earnings. Likewise, if a hedge ceases to qualify for hedge accounting, any change in the fair value of derivative instruments since the last period is recorded to earnings; however, in accordance with SFAS 133, any amounts previously recorded to AOCI would remain there until such time as the original forecasted transaction occurs, then would be reclassified to earnings or if it is determined that continued reporting of losses in AOCI would lead to recognizing a net loss on the combination of the hedging instrument and the hedge transaction in future periods, then the losses would be immediately reclassified to earnings.

Due to the volatility in commodity markets, the Partnership is unable to predict the amount of ineffectiveness each period, including the loss of hedge accounting, which is determined on a derivative by derivative basis. This may result, and has resulted in increased volatility in the Partnership s financial results. Factors that have and may continue to lead to ineffectiveness and unrealized gains and losses on derivative contracts include: the substantial fluctuation in energy prices, the number of derivatives the Partnership holds, and significant weather events that have affected energy production. The number of instances in which the Partnership has discontinued hedge accounting for specific hedges is primarily due to those reasons. However, even though these derivatives may not qualify for hedge accounting under SFAS 133, the Partnership continues to hold the instruments as it believes they continue to afford the Partnership opportunities to manage commodity risk exposure.

As of June 30, 2009 and 2008, the Partnership has both derivative instruments qualifying for hedge accounting under SFAS 133 with fair value changes being recorded in AOCI as a component of partners capital and derivative instruments not designated as hedges being marked to market with all market value adjustments being recorded in earnings.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at June 30, 2009 (all gas quantities are expressed in British Thermal Units, crude oil and natural gas liquids are expressed in barrels). As of June 30, 2009, the remaining term of the contracts extend no later than December 2010, with no single contract longer than one year. For the three months ended June 30, 2009, changes in the fair value of the Partnership s derivative contracts were recorded in both earnings and in AOCI as a component of partners capital.

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	June 30, 2009			
Transaction Type	Total Volume Per Month	Pricing Terms	Remaining Terms of Contracts	Fair Value
Mark to Market Derivatives::				
Crude Oil Swap	3,000 BBL	Fixed price of $70.90 settled against WTI NYMEX average monthly closings	July 2009 to December 2009	$ (36)
Crude Oil Swap	3,000 BBL	Fixed price of $70.90 settled against WTI NYMEX average monthly closings	July 2009 to December 2009	(3)
Crude Oil Swap	1,000 BBL	Fixed price of $70.45 settled against WTI NYMEX average monthly closings	July 2009 to December 2009	(4)
Crude Oil Swap	3,000 BBL	Fixed price of $72.25 settled against WTI NYMEX average monthly closings	January 2010 to December 2010	(89)
Crude Oil Swap	2,000 BBL	Fixed price of $69.15 settled against WTI NYMEX average monthly closings	January 2010 to December 2010	(129)
Crude Oil Swap	1,000 BBL	Fixed price of $104.80 settled against WTI NYMEX average monthly closings	January 2010 to December 2010	343
Total swaps not designated as cash flow hedges				$ 82
Cash Flow Hedges:				

Natural Gas swap	30,000 MMBTU	Fixed price of $9.025 settled against Inside Ferc Columbia Gulf daily average	July 2009 to December 2009	$ 836
Natural Gasoline Swap	2,000 BBL	Fixed price of $86.42 settled against Mt. Belvieu Non-TET natural gasoline average monthly postings.	July 2009 to December 2009	310
Natural Gasoline Swap	1,000 BBL	Fixed price of $94.14 settled against Mt. Belvieu Non-TET natural gasoline average monthly postings	January 2010 to December 2010	351
Total swaps designated as cash flow hedges				$ 1,497
Total net fair value of commodity derivatives				$ 1,579

The Partnership s credit exposure related to mark to market derivatives and commodity cash flow hedges is represented by the fair value of contracts to the Partnership at June 30, 2009. These outstanding contracts expose the Partnership to credit loss in the event of nonperformance by the counterparties to the agreements. The Partnership has incurred no losses associated with counterparty nonperformance on derivative contracts.

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty s financial condition prior to entering into an agreement, and has established a maximum credit limit threshold pursuant to its hedging policy, and monitors the appropriateness of these limits on an ongoing basis. The Partnership has agreements with three counterparties containing collateral provisions. Based on those current agreements, cash deposits are required to be posted whenever the net fair value of derivatives associated with the individual counterparty exceed a specific threshold. If this threshold is exceeded, cash is posted by the Partnership if the value of derivatives is a liability to the Partnership. As of June 30, 2009 the Partnership has no cash collateral deposits posted with counterparties.

The Partnership is exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of gathering, processing and sales activities. The Partnerships gathering and processing revenues are earned under various contractual arrangements with gas producers. Gathering revenues are generated through a combination of fixed-fee and index-related arrangements. Processing revenues are generated primarily through contracts which provide for processing on percent-of-liquids

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(POL) and percent-of-proceeds (POP) basis. The Partnership has entered into hedging transactions through 2010 to protect a portion of its commodity exposure from these contracts. These hedging arrangements are in the form of swaps for crude oil, natural gas, and natural gasoline.

Based on estimated volumes, as of June 30, 2009, the Partnership had hedged approximately 56% and 27% of its commodity risk by volume for 2009 and 2010, respectively. The Partnership anticipates entering into additional commodity derivatives on an ongoing basis to manage its risks associated with these market fluctuations, and will consider using various commodity derivatives, including forward contracts, swaps, collars, futures and options, although there is no assurance that the Partnership will be able to do so or that the terms thereof will be similar to the Partnership s existing hedging arrangements.

The Partnership s principal customers with respect to Prism Gas natural gas gathering and processing are large, natural gas marketing services, oil and gas producers and industrial end-users. In addition, substantially all of the Partnership s natural gas and NGL sales are made at market-based prices. The Partnership s standard gas and NGL sales contracts contain adequate assurance provisions which allows for the suspension of deliveries, cancellation of agreements or discontinuance of deliveries to the buyer unless the buyer provides security for payment in a form satisfactory to the Partnership.

Impact of Cash Flow Hedges

Crude Oil

For the three months ended June 30, 2009 and 2008, net gains and losses on swap hedge contracts decreased crude revenue by $866 and $4,946, respectively. For the six months ended June 30, 2009 and 2008, net gains and losses on swap hedge contracts decreased crude revenue by $686 and $6,037, respectively. As of June 30, 2009 an unrealized derivative fair value gain of $859, related to current and terminated cash flow hedges of crude oil price risk, was recorded in AOCI. Fair value gains of $89, $147 and $623 are expected to be reclassified into earnings in 2009, 2010 and 2011, respectively. The actual reclassification to earnings for contracts remaining in effect will be based on mark-to-market prices at the contract settlement date or for those terminated contracts based on the recorded values at June 30, 2009 adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

Natural Gas

For the three months ended June 30, 2009 and 2008, net gains and losses on swap hedge contracts increased gas revenue by $501 and decreased gas revenue by $626, respectively. For the six months ended June 30, 2009 and 2008, net gains and losses on swap hedge contracts increased gas revenue by $872 and decreased gas revenue by $1,326, respectively. As of June 30, 2009 an unrealized derivative fair value gain of $836 related to cash flow hedges of natural gas was recorded in AOCI. This fair value gain is expected to be reclassified into earnings in 2009. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

Natural Gas Liquids

For the three months ended June 30, 2009 and 2008, net gains and losses on swap hedge contracts decreased liquids revenue by $593 and $477, respectively. For the six months ended June 30, 2009 and 2008, net gains and losses on swap hedge contracts decreased liquids revenue by $196 and $746, respectively. As of June 30, 2009, an unrealized derivative fair value gain of $1,492 related to current and terminated cash flow hedges of natural gas liquids price risk was recorded in AOCI. Fair value gains of $311, $289 and $892 are expected to be reclassified into earnings in 2009, 2010 and 2011, respectively. The actual reclassification to earnings for contracts remaining in effect will be based on mark-to-market prices at the contract settlement date or for those terminated contracts based on the recorded values at June 30, 2009 adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

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(9) Interest Rate Derivatives

The Partnership is exposed to market risks associated with interest rates. The Partnership enters into interest rate swaps to manage interest rate risk associated with the Partnership s variable rate debt and term loan credit facilities. In accordance with SFAS 133, all derivatives and hedging instruments are included on the balance sheet as an asset or a liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in AOCI until such time as the hedged item is recognized in earnings.

The Partnership has entered into several cash flow hedge agreements with an aggregate notional amount of $205,000 to hedge its exposure to increases in the benchmark interest rate underlying its variable rate revolving and term loan credit facilities.

The Partnership designated the following swap agreements as cash flow hedges. Under these swap agreements, the Partnership pays a fixed rate of interest and receives a floating rate based on a one-month or three-month U.S. Dollar LIBOR rate to match the floating rates of the bank facility at which the Partnership periodically elects to borrow. Because these swaps are designated as a cash flow hedge, the changes in fair value, to the extent the swap is effective, are recognized in other comprehensive income until the hedged interest costs are recognized in earnings. At the inception of these hedges, these swaps were identical to the hypothetical swap as of the trade date, and will continue to be identical as long as the accrual periods and rate resetting dates for the debt and these swaps remain equal. This condition results in a 100% effective swap for the following hedges:

Date of Hedge	Notional Amount	Paying Fixed Rate	Receiving Floating Rate	Maturity Date
April 2009	$ 40,000	1.000%	1 Month LIBOR	October 2010
April 2009	$ 25,000	0.720%	1 Month LIBOR	January 2010
March 2009	$ 25,000	1.290%	1 Month LIBOR	September 2010
March 2009	$ 40,000	0.970%	1 Month LIBOR	December 2009
February 2009	$ 75,000	1.295%	1 Month LIBOR	November 2010

The following interest rate swaps have been de-designated as cash flow hedges by the Partnership:

Date of Hedge	Notional Amount	Paying Fixed Rate	Receiving Floating Rate	Maturity Date
September 2007	$ 25,000	4.605%	3 Month LIBOR	September 2010
November 2006	$ 40,000	4.820%	3 Month LIBOR	December 2009
March 2006	$ 75,000	5.250%	3 Month LIBOR	November 2010

October 2008	$	40,000	2.820%	3 Month LIBOR	October 2010
January 2008	$	25,000	3.400%	3 Month LIBOR	January 2010

The following interest rate swaps have not been designated as cash flow hedges by the Partnership:

Date of Hedge		**Notional Amount**	**Paying Fixed Rate**	**Receiving Floating Rate**	**Maturity Date**
November 2006	$	30,000	4.765%	3 Month LIBOR	March 2010

Date of Hedge		**Notional Amount**	**Receiving Fixed Rate**	**Paying Floating Rate**	**Maturity Date**
April 2009	$	25,000	1.070%	3 Month LIBOR	January 2010
April 2009	$	40,000	1.240%	3 Month LIBOR	October 2010
March 2009	$	30,000	0.440%	3 Month LIBOR	September 2009
March 2009	$	40,000	1.420%	3 Month LIBOR	December 2009
March 2009	$	25,000	1.590%	1 Month LIBOR	September 2010
February 2009	$	75,000	1.445%	1 Month LIBOR	November 2010

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These swaps have been recorded at fair value with an offset to current earnings.

The Partnership recognized increases in interest expense of $1,923 and $3,906 for the three and six months ended June 30, 2009, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap and net cash settlement of interest rate hedges.

The Partnership recognized increases in interest expense of $193 and $966 for the three and six months ended June 30, 2008, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap and net cash settlement of interest rate hedges.

The net effective fixed rate for the Partnership s hedged portion of long-term debt is 4.15% as of June 30, 2009. See Note 12 for more information on the Partnership s long-term debt and related interest rates.

(10) Related Party Transactions

Included in the consolidated and condensed financial statements are various related party transactions and balances primarily with Martin Resource Management and affiliates. Related party transactions include sales and purchases of products and services between the Partnership and these related entities as well as payroll and associated costs and allocation of overhead.

The impact of these related party transactions is reflected in the consolidated and condensed financial statements as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues:				
Terminalling and storage	$ 4,845	$ 4,454	$ 8,771	$ 8,232
Marine transportation	4,853	6,219	9,753	12,443
Product sales:				
Natural gas services	27	875	154	2,074
Sulfur services	1,351	4,410	2,880	8,921
Terminalling and storage			11	18
	1,378	5,285	3,045	11,013
	$ 11,706	$ 15,958	$ 21,569	$ 31,688
Costs and expenses:				
Cost of products sold:				
Natural gas services	$ 10,116	$ 28,578	$ 21,341	$ 48,982
Sulfur services	3,445	3,398	6,350	6,716
Terminalling and storage	24	19	229	297
	$ 13,585	$ 31,995	$ 27,920	$ 55,995
Expenses:				
Operating expenses				

Marine transportation	$ 4,962	$ 5,732	$ 9,652	$ 12,956
Natural gas services	374	389	815	773
Sulfur services	1,089	565	2,013	1,114
Terminalling and storage	2,517	2,298	5,428	4,568
	$ 8,942	$ 8,984	$ 17,908	$ 19,411
Selling, general and administrative:				
Natural gas services	$ 190	$ 185	$ 393	$ 385
Sulfur services	506	467	1,040	908
Terminalling and storage				
Indirect overhead allocation, net of reimbursement	875	674	1,751	1,347
	$ 1,571	$ 1,326	$ 3,184	$ 2,640

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(11) Business Segments

The Partnership has four reportable segments: terminalling and storage, natural gas services, marine transportation and sulfur services. The Partnership s reportable segments are strategic business units that offer different products and services. The operating income of these segments is reviewed by the chief operating decision maker to assess performance and make business decisions.

The accounting policies of the operating segments are the same as those described in Note 2 in the Partnership s annual report on Form 10-K for the year ended December 31, 2008 filed with the SEC on March 4, 2009. The Partnership evaluates the performance of its reportable segments based on operating income. There is no allocation of administrative expenses or interest expense.

	Operating Revenues	Intersegment Revenues Eliminations	Operating Revenues after Eliminations	Depreciation and Amortization	Operating Income (loss) after eliminations	Capital Expenditures
Three months ended June 30, 2009						
Terminalling and storage	$ 20,059	$ (1,057)	$ 19,002	$ 2,596	$ 7,732	$ 7,991
Natural gas services	74,829	(7)	74,822	1,115	611	1,116
Marine transportation	16,027	(926)	15,101	3,266	(1,801)	2,928
Sulfur services	19,343		19,343	1,534	5,898	1,385
Indirect selling, general and administrative					(1,393)	
Total	$ 130,258	$ (1,990)	$ 128,268	$ 8,511	$ 11,047	$ 13,420
Three months ended June 30, 2008						
Terminalling and storage	$ 21,795	$ (1,013)	$ 20,782	$ 2,301	$ 2,156	$ 5,375
Natural gas services	182,025		182,025	961	(2,667)	2,590
Marine transportation	20,308	(999)	19,309	2,948	1,993	10,417
Sulfur services	86,445	(418)	86,027	1,404	4,128	774
Indirect selling, general and administrative					(1,315)	
Total	$ 310,573	$ (2,430)	$ 308,143	$ 7,614	$ 4,295	$ 19,156

			Operating		Operating	

	Operating Revenues	Intersegment Revenues Eliminations	Revenues after Eliminations	Depreciation and Amortization	Income (loss) after eliminations	Capital Expenditures
Six months ended June 30, 2009						
Terminalling and storage	$ 44,263	(2,143)	$ 42,120	$ 5,096	$ 9,515	$ 12,721
Natural gas services	165,695	(7)	165,688	2,234	3,362	2,227
Marine transportation	33,270	(1,833)	31,437	6,567	(938)	4,098
Sulfur services	45,929		45,929	3,019	9,191	6,382
Indirect selling, general and administrative					(2,856)	
Total	$ 289,157	$ (3,983)	$ 285,174	$ 16,916	$ 18,274	$ 25,428
Six months ended June 30, 2008						
Terminalling and storage	$ 42,157	(2,079)	$ 40,078	$ 4,442	$ 3,332	$ 9,826
Natural gas services	389,117		389,117	1,938	(2,625)	3,759
Marine transportation	37,289	(1,577)	35,712	5,742	2,785	36,543
Sulfur services	156,686	(434)	156,252	2,832	12,454	2,628
Indirect selling, general and administrative					(2,642)	
Total	$ 625,249	$ (4,090)	$ 621,159	$ 14,954	$ 13,304	$ 52,756

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The following table reconciles operating income to net income:

	Three Months Ended June 30		Six Months Ended June 30	
	2009	**2008**	**2009**	**2008**
Operating income	$ 11,047	$ 4,295	$ 18,274	$ 13,304
Equity in earnings of unconsolidated entities	1,028	4,372	3,088	7,882
Interest expense	(4,183)	(3,895)	(8,852)	(8,638)
Other, net	49	67	71	247
Income taxes	(16)	(522)	214	(461)
Net income	$ 7,925	$ 4,317	$ 12,795	$ 12,334

Total assets by segment are as follows:

	June 30, 2009	December 31, 2008
Total assets:		
Terminalling and storage	$ 144,557	$ 157,598
Natural gas services	236,451	232,161
Marine transportation	137,646	150,733
Sulfur services	114,827	128,424
Total assets	$ 633,481	$ 668,916

(12) Long-term Debt

At June 30, 2009 and December 31, 2008, long-term debt consisted of the following:

	June 30, 2009	December 31, 2008
**$195,000 Revolving loan facility at variable interest rate (4.86%* weighted average at June 30, 2009), due November 2010 secured by substantially all of the Partnership s assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in the Partnership s operating subsidiaries and equity method investees	$ 167,200	$ 165,000
***$130,000 Term loan facility at variable interest rate (6.00%* at June 30, 2009), due November 2010, secured by substantially all of the Partnership assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in Partnership s operating subsidiaries	130,000	130,000
Total long-term debt	297,200	295,000

Less current installments		
Long-term debt, net of current installments	$ 297,200	$ 295,000

* Interest rate fluctuates based on the LIBOR rate plus an applicable margin set on the date of each advance. The margin above LIBOR is set every three months. Indebtedness under the credit facility bears interest at LIBOR plus an applicable margin or the base prime rate plus an applicable margin. The applicable margin for revolving loans that are LIBOR loans ranges from 1.50% to 3.00% and the applicable margin for revolving loans that are base prime rate loans ranges from 0.50% to 2.00%. The applicable margin for term loans that are LIBOR loans ranges from 2.00% to 3.00% and the applicable margin for term

loans that are base prime rate loans ranges from 1.00% to 2.00%. The applicable margin for existing LIBOR borrowings

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is 2.00%. Effective July 1, 2009, the applicable margin for existing LIBOR borrowings will remain at 2.00%. As a result of the Partnership s leverage ratio test as of June 30, 2009, effective October 1, 2009, the applicable margin for existing LIBOR borrowings will also remain at 2.00%. The Partnership incurs a commitment fee on the unused portions of the credit facility.

** Effective October, 2008, the Partnership entered into a cash flow hedge that swaps $40,000 of floating rate to fixed rate. The fixed rate cost is 2.820% plus the Partnership s applicable LIBOR borrowing spread. Effective April 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 2.580% plus the Partnership s applicable LIBOR borrowing spread. These cash flow hedges mature in October, 2010.

** Effective January, 2008, the Partnership entered into a cash flow hedge that swaps $25,000 of floating rate to fixed rate. The fixed rate cost is 3.400% plus the Partnership s applicable LIBOR borrowing spread. Effective April 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 3.050% plus the Partnership s applicable LIBOR borrowing spread. These cash flow hedges mature in January, 2010.

** Effective September, 2007, the Partnership entered into a cash flow hedge that swaps $25,000 of floating rate to fixed rate. The fixed rate cost is 4.605% plus the Partnership s applicable LIBOR borrowing spread. Effective March 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 4.305% plus the Partnership s applicable LIBOR borrowing spread. These cash flow hedges mature in September, 2010.

** Effective November, 2006, the Partnership entered into a cash flow hedge that swaps $40,000 of floating rate to fixed rate. The fixed rate cost is 4.82% plus the Partnership s applicable LIBOR borrowing spread. Effective March 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 4.37% plus the Partnership s applicable LIBOR borrowing spread. These cash flow hedges mature in December, 2009.

*** The $130,000 term loan has $105,000 hedged. Effective March, 2006, the Partnership entered into a cash flow hedge that swaps $75,000 of floating rate to fixed rate. The fixed rate cost is 5.25% plus the Partnership s applicable LIBOR borrowing spread. Effective February 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 5.10% plus the Partnership s applicable LIBOR borrowing spread. These cash flow hedges mature in November, 2010. Effective

November 2006, the Partnership entered into an additional interest rate swap that swaps $30,000 of floating rate to fixed rate. The fixed rate cost is 4.765% plus the Partnership s applicable LIBOR borrowing spread. Effective March 2009, the Partnership entered a subsequent swap to lower its effective fixed rate to 4.325% plus the Partnership s applicable LIBOR borrowing spread. These cash flow hedges mature in March, 2010.

On November 10, 2005, the Partnership entered into a new $225,000 multi-bank credit facility comprised of a $130,000 term loan facility and a $95,000 revolving credit facility, which includes a $20,000 letter of credit sub-limit. This credit facility also includes procedures for additional financial institutions to become revolving lenders, or for any existing revolving lender to increase its revolving commitment, subject to a maximum of $100,000 for all such increases in revolving commitments of new or existing revolving lenders. Effective June 30, 2006, the Partnership increased its revolving credit facility $25,000 resulting in a committed $120,000 revolving credit facility. Effective December 28, 2007, the Partnership increased its revolving credit facility $75,000 resulting in a committed $195,000 revolving credit facility. The revolving credit facility is used for ongoing working capital needs and general partnership purposes, and to finance permitted investments, acquisitions and capital expenditures. Under the amended and restated credit facility, as of June 30, 2009, the Partnership had $167,200 outstanding under the revolving credit facility and $130,000 outstanding under the term loan facility. As of June 30, 2009, irrevocable letters of credit issued under the Partnership s credit facility totaled $2.1 million. As of June 30, 2009, the Partnership had $25,680 available under its revolving credit facility.

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The Partnership s obligations under the credit facility are secured by substantially all of the Partnership s assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in its operating subsidiaries and equity method investees. The Partnership may prepay all amounts outstanding under this facility at any time without penalty.

In addition, the credit facility contains various covenants, which, among other things, limit the Partnership s ability to: (i) incur indebtedness; (ii) grant certain liens; (iii) merge or consolidate unless it is the survivor; (iv) sell all or substantially all of its assets; (v) make certain acquisitions; (vi) make certain investments; (vii) make certain capital expenditures; (viii) make distributions other than from available cash; (ix) create obligations for some lease payments; (x) engage in transactions with affiliates; (xi) engage in other types of business; and (xii) its joint ventures to incur indebtedness or grant certain liens.

The credit facility also contains covenants, which, among other things, require the Partnership to maintain specified ratios of: (i) minimum net worth (as defined in the credit facility) of $75,000 plus 50% of net proceeds from equity issuances after November 10, 2005; (ii) EBITDA (as defined in the credit facility) to interest expense of not less than 3.0 to 1.0 at the end of each fiscal quarter; (iii) total funded debt to EBITDA of not more than 4.75 to 1.00 for each fiscal quarter; and (iv) total secured funded debt to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter. The Partnership was in compliance with the covenants contained in the credit facility as of June 30, 2009 and for the year ended December 31, 2008.

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls the Partnership s general partner, the lenders under the Partnership s credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, an event of default by Martin Resource Management under its credit facility could independently result in an event of default under the Partnership s credit facility if it is deemed to have a material adverse effect on the Partnership. Any event of default and corresponding acceleration of outstanding balances under the Partnership s credit facility could require the Partnership to refinance such indebtedness on unfavorable terms and would have a material adverse effect on the Partnership s financial condition and results of operations as well as its ability to make distributions to unitholders.

On November 10 of each year, commencing with November 10, 2006, the Partnership must prepay the term loans under the credit facility with 75% of Excess Cash Flow (as defined in the credit facility), unless its ratio of total funded debt to EBITDA is less than 3.00 to 1.00. There were no prepayments made or required under the term loan through June 30, 2009. If the Partnership receives greater than $15,000 from the incurrence of indebtedness other than under the credit facility, it must prepay indebtedness under the credit facility with all such proceeds in excess of $15,000. Any such prepayments are first applied to the term loans under the credit facility. The Partnership must prepay revolving loans under the credit facility with the net cash proceeds from any issuance of its equity. The Partnership must also prepay indebtedness under the credit facility with the proceeds of certain asset dispositions. Other than these mandatory prepayments, the credit facility requires interest only payments on a quarterly basis until maturity. All outstanding principal and unpaid interest must be paid by November 10, 2010. The credit facility contains customary events of default, including, without limitation, payment defaults, cross-defaults to other material indebtedness, bankruptcy-related defaults, change of control defaults and litigation-related defaults.

Draws made under the Partnership s credit facility are normally made to fund acquisitions and for working capital requirements. During the current fiscal year, draws on the Partnership s credit facility have ranged from a low of $285,000 to a high of $315,000. As of June 30, 2009, the Partnership had $25,680 available for working capital, internal expansion and acquisition activities under the Partnership s credit facility.

In connection with the Partnership s Stanolind asset acquisition on January 22, 2008, the Partnership borrowed approximately $6,000 under its revolving credit facility.

The Partnership paid cash interest in the amount of $4,518 and $4,107 for the three months ended June 30, 2009 and

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2008, respectively, and $9,443 and $7,927 for the six months ended June 30, 2009 and 2008, respectively. Capitalized interest was $70 and $361 for the three months ended June 30, 2009 and 2008, respectively and $238 and $813 for the six months ended June 30, 2009 and 2008, respectively.

(13) Income Taxes

The operations of a partnership are generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. Effective January 1, 2007, the Partnership is subject to the Texas margin tax as described below. Woodlawn, a subsidiary of the Partnership, is subject to income taxes due to its corporate structure. A current federal income tax benefit of $32 and $321 and a current federal income tax expense of $411 and $247 related to the operation of the subsidiary, were recorded for the three and six months ended June 30, 2009 and 2008, respectively. State income taxes attributable to the Texas margin tax incurred by the subsidiary were $7 and $12 for the three and six months ended June 30, 2009 and $13 and $19 for the three and six months ended June 30, 2008, respectively. In connection with the Woodlawn acquisition, the Partnership also established deferred income taxes of $8,964 associated with book and tax basis differences of the acquired assets and liabilities. The basis differences are primarily related to property, plant and equipment.

A deferred tax benefit related to these basis differences of $120 and $75 was recorded for the three months ended June 30, 2009 and 2008, respectively, and $214 and $155 was recorded for the six months ended June 30, 2009 and 2008, respectively. A deferred tax liability of $8,324 and $8,538 related to the basis differences existed at June 30, 2009 and at December 31, 2008, respectively.

In 2006, the Texas Governor signed into law a Texas margin tax (H.B. No. 3) which restructures the state business tax by replacing the taxable capital and earned surplus components of the current franchise tax with a new taxable margin component. Since the tax base on the Texas margin tax is derived from an income-based measure, the margin tax is construed as an income tax and, therefore, the provisions of SFAS 109 regarding the recognition of deferred taxes apply to the new margin tax. The impact on deferred taxes as a result of this provision is immaterial. State income taxes attributable to the Texas margin tax of $168 and $321 were recorded in current income tax expense for the three and six months ended June 30, 2009 and $186 and $369 for the three and six months ended June 30, 2008, respectively.

The components of income tax expense (benefit) from operations recorded for the three and six months ended June 30, 2009 and 2008 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
Current:				
Federal	$ (32)	$ 411	$ (321)	$ 247
State	168	186	321	369
	136	597		616
Deferred:				
Federal	(120)	(75)	(214)	(155)
	$ 16	$ 522	$ (214)	$ 461

(14) Hurricane Damage

During the third quarter of 2008, several of the Partnership s facilities in the Gulf of Mexico were in the path of two major hurricanes, Hurricane Gustav and Hurricane Ike. Physical damage to the Partnership s assets caused by the hurricanes, as well as the related removal and recovery costs, are covered by insurance subject to a deductible. Losses incurred as a result of a single hurricane (an occurrence) are limited to a maximum aggregate deductible of $250 for flood damage and $1,000 minimum plus 2% of total insured value at each location for wind damage. The partnership s total flood coverage is $15,000 and total wind coverage is $100,000.

The most significant damage to the Partnership s assets was sustained at the Neches location. Property damage also occurred at the Partnership s Galveston, Sabine Pass, Intracoastal City, Cameron East,

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Cameron West, Freeport, Venice, Port Fourchon, Stanolind, Mont Belvieu, and Spindletop locations. Based on an analysis of the damage, the Partnership has estimated its non-cash charge as $1,269 for all locations which is equal to the net-book value of the damaged assets. A receivable of $2,604 has been recorded for the expected insurance recovery equal to the impairment charge and for all expenditures related to water damage less the aforementioned deductible. This receivable was also reduced by the advanced insurance proceeds received of $5,027. Insurance proceeds received as a result of the aforementioned claims could exceed net book value of the Partnership s assets determined to be impaired, which will result in the recognition of a gain equal to the amount of the excess. No net gain or loss has been recognized from the impairment of these damaged assets at June 30, 2009. This potential gain would not be recognized until proceeds are received.

(15) Gain on Disposal of Assets

On April 30, 2009, the Partnership sold the assets comprising the Mont Belvieu railcar unloading facility, which yielded net proceeds from the sale in the amount of $19,610. This disposition was separated into two phases. The disposition related to phase I was comprised of property, plant and equipment and allocated goodwill included in the Partnership s terminalling segment with a carrying value of $14,329. This transaction yielded a gain on sale of property, plant, and equipment in the amount of $5,281, a portion which was deferred in the amount of $200 for expected future warranty costs associated with the sale. The gain is included in other operating income in the consolidated statement of operations. At June 30, 2009, a portion of the property, plant and equipment is under construction and the Partnership is expected to make additional expenditures which will increase the carrying value of the disposed assets by approximately $1,320. The current balance related to phase II construction is $680 and is included in other assets in the consolidated balance sheet. The Partnership will receive an additional $2,750 upon completion of the construction project. The Partnership expects to recognize a gain in the approximate amount of $750 during the third quarter of 2009. Additionally, the Partnership expects to receive payments of $375 in April 2010 and April 2012, respectively, which represents payments from an indemnity escrow resulting from the sale. The Partnership expects to record these amounts as gains in each respective quarter. The Partnership paid down the outstanding revolving loans under its credit facility with the net cash proceeds from this sale of assets. The amount paid down is available for future borrowings under the revolving credit facility.

(16) Commitments and Contingencies

As a result of a routine inspection by the U.S. Coast Guard of the Partnership s tug Martin Explorer at the Freeport Sulfur Dock Terminal in Tampa, Florida, the Partnership has been informed that an investigation has been commenced concerning a possible violation of the Act to Prevent Pollution from Ships, 33 USC 1901, et. seq., and the MARPOL Protocol 73/78. In connection with this matter, two employees of Martin Resource Management who provide services to the Partnership were served with grand jury subpoenas during the fourth quarter of 2007. In addition, in April of 2009, an additional grand jury subpoena was issued pertaining to the provision of certain documents relating to the Martin Explorer and its crew. The Partnership is cooperating with the investigation and, as of the date of this report, no formal charges, fines and/or penalties have been asserted against the Partnership.

In addition to the foregoing, from time to time, the Partnership is subject to various claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Partnership.

On May 2, 2008, the Partnership received a copy of a petition filed in the District Court of Gregg County, Texas (the Court) by Scott D. Martin (the Plaintiff) against Ruben S. Martin, III (the Defendant) with respect to certain matters relating to Martin Resource Management. The Plaintiff and the Defendant are executive officers of Martin Resource Management and the general partner of the Partnership, the Defendant is a director of both Martin Resource Management and the general partner of the Partnership, and the Plaintiff is a director of Martin Resource Management. The lawsuit alleged that the Defendant breached a settlement agreement with the Plaintiff concerning certain Martin Resource Management matters and that the Defendant breached fiduciary duties allegedly owed to the Plaintiff in connection with their

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respective ownership and other positions with Martin Resource Management. Prior to the trial of this lawsuit, the Plaintiff dropped his claims against the Defendant relating to the breach of fiduciary duty allegations. The Partnership is not a party to the lawsuit and the lawsuit does not assert any claims (i) against the Partnership, (ii) concerning the Partnership s governance or operations or (iii) against the Defendant with respect to his service as an officer or director of the general partner of the Partnership.

In May 2009, the lawsuit went to trial and on June 18, 2009, the Court entered a judgment (the Judgment) with respect to the lawsuit as further described below. In connection with the Judgment, the Defendant has advised the Partnership that he has filed a motion for new trial, a motion for judgment notwithstanding the verdict and a notice of appeal. In addition, on June 22, 2009, the Plaintiff filed a notice of appeal with the Court indicating his intent to appeal the Judgment. The Defendant has further advised the Partnership that on June 30, 2009 he posted a cash deposit in lieu of a bond and the judge has ruled that as a result of such deposit, the enforcement of any of the provisions in the Judgment is stayed until the matter is resolved on appeal. Accordingly, during the pendancy of the appeal process, no change in the makeup of the Martin Resource Management Board of Directors is expected.

The Judgment awarded the Plaintiff monetary damages in the approximate amount of $3.2 million, attorney s fees of approximately $1.6 million and interest. In addition, the Judgment grants specific performance and provides that the Defendant is to (i) transfer one share of his Martin Resource Management common stock to the Plaintiff, (ii) take such actions, including the voting of any Martin Resource Management shares which the Defendant owns, controls or otherwise has the power to vote, as are necessary to change the composition of the Board of Directors of Martin Resource Management from a five-person board, currently consisting of the Defendant and the Plaintiff as well as Wes Skelton, Don Neumeyer, and Bob Bondurant (executive officers of Martin Resource Management and the Partnership), to a four-person board to consist of the Defendant and his designee and the Plaintiff and his designee, and (iii) take such actions as are necessary to change the trustees of the Martin Resource Management Employee Stock Ownership Trust (the MRMC ESOP Trust), currently consisting of the Defendant, the Plaintiff and Wes Skelton, to just the Defendant and the Plaintiff. The Judgment is directed solely at the Defendant and is not binding on any other officer, director or shareholder of Martin Resource Management or any trustee of a trust owning Martin Resource Management shares. The Judgment with respect to (ii) above will terminate on February 17, 2010, and with respect to (iii) above on the 30th day after the election by the Martin Resource Management shareholders of the first successor Martin Resource Management board after February 17, 2010.

On September 5, 2008, the Plaintiff and one of his affiliated partnerships (the SDM Plaintiffs), on behalf of themselves and derivatively on behalf of Martin Resource Management, filed suit in a Harris County, Texas district court against Martin Resource Management, the Defendant, Robert Bondurant, Donald R. Neumeyer and Wesley Skelton, in their capacities as directors of Martin Resource Management (the MRMC Director Defendants), as well as 35 other officers and employees of Martin Resource Management (the Other MRMC Defendants). In addition to their respective positions with Martin Resource Management, Robert Bondurant, Donald Neumeyer and Wesley Skelton are officers of the general partner of the Partnership. The Partnership is not a party to this lawsuit, and it does not assert any claims (i) against the Partnership, (ii) concerning the Partnership s governance or operations or (iii) against the MRMC Director Defendants or Other MRMC Defendants with respect to their service to the Partnership.

The SDM Plaintiffs allege, among other things, that the MRMC Director Defendants have breached their fiduciary duties owed to Martin Resource Management and the SDM Plaintiffs, entrenched their control of Martin Resource Management and diluted the ownership position of the SDM Plaintiffs and certain other minority shareholders in Martin Resource Management, and engaged in acts of unjust enrichment, excessive compensation, waste, fraud and conspiracy with respect to Martin Resource Management. The SDM Plaintiffs seek, among other things, to rescind the June 2008 issuance by Martin Resource Management of shares of its common stock under its 2007 Long-Term Incentive Plan to the Other MRMC Defendants, remove the MRMC Director Defendants as officers and directors of

Martin Resource Management, prohibit the Defendant, Wesley Skelton and Robert Bondurant from serving as trustees of the MRMC Employee Stock Ownership Plan, and place all of the Martin Resource Management common shares

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owned or controlled by the Defendant in a constructive trust that prohibits him from voting those shares. The SDM Plaintiffs have amended their Petition to eliminate their claims regarding rescission of the issue by Martin Resource Management of shares of its common stock to the MRMC Employee Stock Ownership Plan. The Court abated this lawsuit on July 13, 2009 until a mandamus pending before the Texas Supreme Court dealing with matters at issue in the lawsuit is resolved.

The lawsuits described above are in addition to (i) a separate lawsuit filed in July 2008 in a Gregg County, Texas district court by the daughters of the Defendant against the Plaintiff, both individually and in his capacity as trustee of the Ruben S. Martin, III Dynasty Trust, which suit alleges, among other things, that the Plaintiff has engaged in self-dealing in his capacity as a trustee under the trust, which holds shares of Martin Resource Management common stock, and has breached his fiduciary duties owed to the plaintiffs, and who are beneficiaries of such trust, and (ii) a separate lawsuit filed in October 2008 in the United States District Court for the Eastern District of Texas by Angela Jones Alexander against the Defendant and Karen Yost in their capacities as a former trustee and a trustee, respectively, of the R.S. Martin Jr. Children Trust No. One (f/b/o Angela Santi Jones), which holds shares of Martin Resource Management common stock, which suit alleges, among other things that the Defendant and Karen Yost breached the fiduciary duties owed to the plaintiff, who is the beneficiary of such trust, and seeks to remove Karen Yost as the trustee of such trust. With respect to the lawsuit described in (i) above, it should be noted that the Plaintiff has resigned as a trustee of the Ruben S. Martin, III Dynasty Trust. With respect to the lawsuit described in (ii) above, Angela Jones Alexander has amended her claims to include her grandmother, Margaret Martin, as a party.

On September 24, 2008, Martin Resource Management removed Plaintiff as a director of the general partner of the Partnership. Such action was taken as a result of the collective effect of Plaintiff s then recent activities, which the Board of Directors of Martin Resource Management determined were detrimental to both Martin Resource Management and the Partnership. The Plaintiff does not serve on any committees of the board of directors of the general partner of the Partnership. The position on the board of directors of the general partner of the Partnership vacated by the Plaintiff may be filled in accordance with the existing procedures for replacement of a departing director utilizing the Nominations Committee of the board of directors of the general partner of the Partnership. This position on the board of directors has not been filled as of August 5, 2009.

(17) Consolidating Financial Statements

In connection with the Partnership s filing of a shelf registration statement on Form S-3 with the Securities and Exchange Commission (the Registration Statement), Martin Operating Partnership L.P. (the Operating Partnership), the Partnership s wholly-owned subsidiary, may issue unconditional guarantees of senior or subordinated debt securities of the Partnership in the event that the Partnership issues such securities from time to time under the registration statement. If issued, the guarantees will be full, irrevocable and unconditional. In addition, the Operating Partnership may also issue senior or subordinated debt securities under the Registration Statement which, if issued, will be fully, irrevocably and unconditionally guaranteed by the Partnership. The Partnership does not provide separate financial statements of the Operating Partnership because the Partnership has no independent assets or operations, the guarantees are full and unconditional and the other subsidiary of the Partnership is minor. There are no significant restrictions on the ability of the Partnership or the Operating Partnership to obtain funds from any of their respective subsidiaries by dividend or loan.

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

References in this quarterly report to Martin Resource Management refers to Martin Resource Management Corporation and its subsidiaries, unless the context otherwise requires. You should read the following discussion of our financial condition and results of operations in conjunction with the consolidated and condensed financial statements and the notes thereto included elsewhere in this quarterly report.

Forward-Looking Statements

This quarterly report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements included in this quarterly report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including forecast, may, believe, will, expect, anticipate, estimate, continue similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other forward-looking information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

These forward-looking statements are made based upon management s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under Item 1A. Risk Factors of our Form 10-K for the year ended December 31, 2008 filed with the Securities and Exchange Commission (the SEC) on March 4, 2009.

Overview

We are a publicly traded limited partnership with a diverse set of operations focused primarily in the United States Gulf Coast region. Our four primary business lines include:

- Terminalling and storage services for petroleum and by-products;
- Natural gas services;
- Marine transportation services for petroleum products and by-products; and
- Sulfur and sulfur-based products gathering, processing, marketing, manufacturing and distribution.

The petroleum products and by-products we collect, transport, store and market are produced primarily by major and independent oil and gas companies who often turn to third parties, such as us, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. We operate primarily in the Gulf Coast region of the United States. This region is a major hub for petroleum refining, natural gas gathering and processing and support services for the exploration and production industry.

We were formed in 2002 by Martin Resource Management, a privately-held company whose initial predecessor was incorporated in 1951 as a supplier of products and services to drilling rig contractors. Since then, Martin Resource Management has expanded its operations through acquisitions and internal expansion initiatives as its management identified and capitalized on the needs of producers and purchasers of hydrocarbon products and by-products and other bulk liquids. Martin Resource Management owns an approximate 34.9% limited partnership interest in us. Furthermore, it owns and controls our general partner, which owns a 2.0% general partner interest in us and all of our incentive distribution rights.

Martin Resource Management has operated our business for several years. Martin Resource Management began operating our natural gas services business in the 1950s and our sulfur business in the 1960s. It began our marine transportation business in the late 1980s. It entered into our fertilizer and terminalling and storage businesses in the early 1990s. In recent years, Martin Resource Management has increased the size of our asset base through expansions and strategic acquisitions.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations are based on the historical consolidated and condensed financial statements included elsewhere herein. We prepared these financial statements in conformity with generally accepted accounting principles. The preparation of these financial statements required us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. We based our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Our results may differ from these estimates. Currently, we believe that our accounting policies do not require us to make estimates using assumptions about matters that are highly uncertain. However, we have described below the critical accounting policies that we believe could impact our consolidated and condensed financial statements most significantly.

You should also read Note 1, General in Notes to Consolidated and Condensed Financial Statements contained in this quarterly report and the Significant Accounting Policies note in the consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2008 filed with the SEC on March 4, 2009 in conjunction with this Management s Discussion and Analysis of Financial Condition and Results of Operations. Some of the more significant estimates in these financial statements include the amount of the allowance for doubtful accounts receivable and the determination of the fair value of our reporting units under SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142).

Derivatives

In accordance with Statement of Financial Accounting Standards No. 133 (SFAS No. 133), *Accounting for Derivative Instruments and Hedging Activities*, all derivatives and hedging instruments are included on the balance sheet as an asset or liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings. Our hedging policy allows us to use hedge accounting for financial transactions that are designated as hedges. Derivative instruments not designated as hedges or hedges that become ineffective are being marked to market with all market value adjustments being recorded in the consolidated statements of operations. As of June 30, 2009, we have designated a portion of our derivative instruments as qualifying cash flow hedges. Fair value changes for these hedges have been recorded in other comprehensive income as a component of partners capital.

Product Exchanges

We enter into product exchange agreements with third parties whereby we agree to exchange natural gas liquids (NGLs) and sulfur with third parties. We record the balance of exchange products due to other companies under these agreements at quoted market product prices and the balance of exchange products due from other companies at the lower of cost or market. Cost is determined using the first-in, first-out method.

Revenue Recognition

Revenue for our four operating segments is recognized as follows:

Terminalling and storage Revenue is recognized for storage contracts based on the contracted monthly tank fixed fee. For throughput contracts, revenue is recognized based on the volume moved through our terminals at the contracted rate. When lubricants and drilling fluids are sold by truck, revenue is recognized upon delivering product to the customers as title to the product transfers when the customer physically receives the product.

Natural gas services Natural gas gathering and processing revenues are recognized when title passes or service is performed. NGL distribution revenue is recognized when product is delivered by truck to our NGL customers, which occurs when the customer physically receives the product. When product is sold in

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storage, or by pipeline, we recognize NGL distribution revenue when the customer receives the product from either the storage facility or pipeline.

Marine transportation Revenue is recognized for contracted trips upon completion of the particular trip. For time charters, revenue is recognized based on a per day rate.

Sulfur services Revenue is recognized when the customer takes title to the product at our plant or the customer facility.

Equity Method Investments

We use the equity method of accounting for investments in unconsolidated entities where the ability to exercise significant influence over such entities exists. Investments in unconsolidated entities consist of capital contributions and advances plus our share of accumulated earnings as of the entities latest fiscal year-ends, less capital withdrawals and distributions. Investments in excess of the underlying net assets of equity method investees, specifically identifiable to property, plant and equipment, are amortized over the useful life of the related assets. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment, annually. Under the provisions SFAS No. 142, *Goodwill and Other Intangible Assets,* this goodwill is not subject to amortization and is accounted for as a component of the investment. Equity method investments are subject to impairment under the provisions of Accounting Principles Board (APB) Opinion No. 18, The *Equity Method of Accounting for Investments in Common Stock.* No portion of the net income from these entities is included in our operating income.

We own an unconsolidated 50% of the ownership interests in Waskom Gas Processing Company (Waskom), Matagorda Offshore Gathering System (Matagorda), Panther Interstate Pipeline Energy LLC (PIPE) and a 20% ownership interest in a partnership which owns the lease rights to Bosque County Pipeline (BCP). Each of these interests is accounted for under the equity method of accounting. The lease contract with respect to BCP terminated in June 2009 and the investment was fully amortized as of June 30, 2009.

Goodwill

Goodwill is subject to a fair-value based impairment test on an annual basis. We are required to identify our reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets. We are required to determine the fair value of each reporting unit and compare it to the carrying amount of the reporting unit. To the extent the carrying amount of a reporting unit exceeds the fair value of the reporting unit, we would be required to perform the second step of the impairment test, as this is an indication that the reporting unit goodwill may be impaired.

All four of our reporting units , terminalling, marine transportation, natural gas services and sulfur services, contain goodwill.

As of December 31, 2008, we determined fair value in each reporting unit based on a multiple of current annual cash flows. This multiple was derived from our experience with actual acquisitions and dispositions and our valuation of recent potential acquisitions and dispositions.

Environmental Liabilities

We have historically not experienced circumstances requiring us to account for environmental remediation obligations. If such circumstances arise, we would estimate remediation obligations utilizing a remediation feasibility study and any other related environmental studies that we may elect to perform. We would record changes to our estimated environmental liability as circumstances change or events occur, such as the issuance of revised orders by governmental bodies or court or other judicial orders and our evaluation of the likelihood and amount of the related eventual liability.

Allowance for Doubtful Accounts

In evaluating the collectability of our accounts receivable, we assess a number of factors, including a specific customer s ability to meet its financial obligations to us, the length of time the receivable has been past due and historical collection experience. Based on these assessments, we record specific and general reserves for bad debts to reduce the related receivables to the amount we ultimately expect to collect from customers.

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Asset Retirement Obligation

We recognize and measure our asset and conditional asset retirement obligations and the associated asset retirement cost upon acquisition of the related asset and based upon the estimate of the cost to settle the obligation at its anticipated future date. The obligation is accreted to its estimated future value and the asset retirement cost is depreciated over the estimated life of the asset.

Our Relationship with Martin Resource Management

Martin Resource Management is engaged in the following principal business activities:

- providing land transportation of various liquids using a fleet of trucks and road vehicles and road trailers;
- distributing fuel oil, asphalt, sulfuric acid, marine fuel and other liquids;
- providing marine bunkering and other shore-based marine services in Alabama, Louisiana, Mississippi and Texas;
- operating a small crude oil gathering business in Stephens, Arkansas;
- operating a lube oil processing facility in Smackover, Arkansas;
- operating an underground NGL storage facility in Arcadia, Louisiana;
- supplying employees and services for the operation of our business;
- operating, for its account and our account, the docks, roads, loading and unloading facilities and other common use facilities or access routes at our Stanolind terminal;
- operating, solely for our account, the asphalt facilities in Omaha, Nebraska.

We are and will continue to be closely affiliated with Martin Resource Management as a result of the following relationships.

Ownership

Martin Resource Management owns an approximate 34.9% limited partnership interest and a 2% general partnership interest in us and all of our incentive distribution rights.

Management

Martin Resource Management directs our business operations through its ownership and control of our general partner. We benefit from our relationship with Martin Resource Management through access to a significant pool of management expertise and established relationships throughout the energy industry. We do not have employees. Martin Resource Management employees are responsible for conducting our business and operating our assets on our behalf.

Related Party Agreements

We are a party to an omnibus agreement with Martin Resource Management. The omnibus agreement requires us to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. We reimbursed Martin Resource Management for $15.7 million of direct costs and expenses for the three months ended June 30, 2009 compared to $16.3 million for the three months ended June 30, 2008. We reimbursed Martin Resource Management for $30.1 million of direct costs and expenses for the six months ended June 30, 2009 compared to $33.9 million for the six months ended June 30, 2008. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses.

In addition to the direct expenses, under the omnibus agreement, the reimbursement amount that we are required to pay to Martin Resource Management with respect to indirect general and administrative and corporate overhead expenses was capped at $2.0 million. This cap expired on November 1, 2007. Effective October 1, 2008 through September 30, 2009, the Conflicts Committee of our general partner approved an annual reimbursement amount for indirect expenses of $3.5 million. We reimbursed Martin Resource Management for $0.9 and $0.7 million of indirect expenses for the three months ended June 30, 2009 and 2008, respectively. We reimbursed Martin Resource Management for $1.8 and $1.3 million of indirect expenses for the six months ended June 30, 2009 and 2008, respectively. These indirect expenses covered the centralized corporate functions Martin Resource Management provides for us, such as accounting, treasury, clerical billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. The omnibus agreement also contains significant non-compete provisions and indemnity obligations. Martin Resource Management also licenses certain of its trademarks and trade names to us under the omnibus agreement.

In addition to the omnibus agreement, we and Martin Resource Management have entered into various other agreements that are not the result of arm s-length negotiations and consequently may not be as favorable to us as they might have been if we had negotiated them with unaffiliated third parties. The agreements include, but are not limited to, a motor carrier agreement, a terminal services agreement, a marine transportation agreement, a product storage agreement, a product supply agreement, a throughput agreement, and a Purchaser Use Easement, Ingress-Egress Easement and Utility Facilities Easement. Pursuant to the terms of the omnibus agreement, we are prohibited from entering into certain material agreements with Martin Resource Management without the approval of the conflicts committee of our general partner s board of directors.

For a more comprehensive discussion concerning the omnibus agreement and the other agreements that we have entered into with Martin Resource Management, please refer to Item 13. Certain Relationships and Related Transactions Agreements set forth in our annual report on Form 10-K for the year ended December 31, 2008 filed with the SEC on March 4, 2009.

Commercial

We have been and anticipate that we will continue to be both a significant customer and supplier of products and services offered by Martin Resource Management. Our motor carrier agreement with Martin Resource Management provides us with access to Martin Resource Management s fleet of road vehicles and road trailers to provide land transportation in the areas served by Martin Resource Management. Our ability to utilize Martin Resource Management s land transportation operations is currently a key component of our integrated distribution network.

We also use the underground storage facilities owned by Martin Resource Management in our natural gas services operations. We lease an underground storage facility from Martin Resource Management in Arcadia, Louisiana with a storage capacity of 2.0 million barrels. Our use of this storage facility gives us greater flexibility in our operations by allowing us to store a sufficient supply of product during times of decreased demand for use when demand increases.

In the aggregate, our purchases of land transportation services, NGL storage services, sulfuric acid and lube oil product purchases and sulfur services payroll reimbursements from Martin Resource Management accounted for approximately 16% and 12% of our total cost of products sold during the three months ended June 30, 2009 and 2008, respectively; and approximately 14% and 10% of our total cost of products sold during the six months ended June 30, 2009 and 2008, respectively. We also purchase marine fuel from Martin Resource Management, which we account for as an operating expense.

Correspondingly, Martin Resource Management is one of our significant customers. It primarily uses our terminalling, marine transportation and NGL distribution services for its operations. We provide terminalling and storage services under a terminal services agreement. We provide marine transportation services to Martin Resource Management under a charter agreement on a spot-contract basis at applicable market rates. Our sales to Martin Resource

Management accounted for approximately 9% and 5% of our total revenues for the three months ended June 30, 2009 and 2008, respectively. Our sales to Martin Resource Management accounted for approximately 8% and 5% of our total revenues for the six months ended June 30, 2009 and 2008, respectively. We provide terminalling and storage and marine transportation services to Midstream Fuel and Midstream Fuel provides terminal services to us to handle lubricants, greases and drilling fluids.

In April 2009, we sold our traditional lubricant business to Martin Resource Management in return for a service fee for lubricant volume moved through our terminals.

For a more comprehensive discussion concerning the agreements that we have entered into with Martin Resource Management, please refer to Item 13. Certain Relationships and Related Transactions Agreements set forth in our annual report on Form 10-K for the year ended December 31, 2008 filed with the SEC on March 4, 2009.

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or to our management, as appropriate. If the board of directors is involved in the approval process, it determines whether to refer the matter to the Conflicts Committee of our general partner s board of directors, as constituted under our limited partnership agreement. If a matter is referred to the Conflicts Committee, it obtains information regarding the proposed transaction from management and determines whether to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the Conflicts Committee retains such counsel or financial advisor, it considers such advice and, in the case of a financial advisor, such advisor s opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Results of Operations

The results of operations for the three and six months ended June 30, 2009 and 2008 have been derived from our consolidated and condensed financial statements.

We evaluate segment performance on the basis of operating income, which is derived by subtracting cost of products sold, operating expenses, selling, general and administrative expenses, and depreciation and amortization expense from revenues. The following table sets forth our operating revenues and operating income by segment for the three months and six months ended June 30, 2009 and 2008. The results of operations for the first six months of the year are not necessarily indicative of the results of operations which might be expected for the entire year.

	Operating Revenues	Revenues Intersegment Eliminations	Operating Revenues after Eliminations	Operating Income (loss)	Operating Income Intersegment Eliminations	Operating Income (loss) after Eliminations
			(In thousands)			
Three months ended June 30, 2009						
Terminalling and storage	$ 20,059	$ (1,057)	$ 19,002	$ 8,500	$ (768)	$ 7,732
Natural gas services	74,829	(7)	74,822	348	263	611
Marine transportation	16,027	(926)	15,101	(881)	(920)	(1,801)
Sulfur services	19,343		19,343	4,473	1,425	5,898
Indirect selling, general and administrative				(1,393)		(1,393)
Total	$ 130,258	$ (1,990)	$ 128,268	$ 11,047	$	$ 11,047

Three months ended June 30, 2008						
Terminalling and storage	$ 21,795	$ (1,013)	$ 20,782	$ 3,025	$ (869)	$ 2,156
Natural gas services	182,025		182,025	(2,907)	240	(2,667)
Marine transportation	20,308	(999)	19,309	2,552	(559)	1,993
Sulfur services	86,445	(418)	86,027	2,940	1,188	4,128
Indirect selling, general and administrative				(1,315)		(1,315)

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	Operating Revenues	Revenues Intersegment Eliminations	Operating Revenues after Eliminations	Operating Income (loss)	Operating Income Intersegment Eliminations	Operating Income (loss) after Eliminations
			(In thousands)			
Total	$ 310,573	$ (2,430)	$ 308,143	$ 4,295	$	$ 4,295
Six months ended June 30, 2009						
Terminalling and storage	$ 44,263	$ (2,143)	$ 42,120	$ 11,090	$ (1,575)	$ 9,515
Natural gas services	165,695	(7)	165,688	2,829	533	3,362
Marine transportation	33,270	(1,833)	31,437	844	(1,782)	(938)
Sulfur services	45,929		45,929	6,367	2,824	9,191
Indirect selling, general and administrative				(2,856)		(2,856)
Total	$ 289,157	$ (3,983)	$ 285,174	$ 18,274	$	$ 18,274
Six months ended June 30, 2008						
Terminalling and storage	$ 42,157	$ (2,079)	$ 40,078	$ 5,134	$ (1,802)	$ 3,332
Natural gas services	389,117		389,117	(3,089)	464	(2,625)
Marine transportation	37,289	(1,577)	35,712	3,852	(1,067)	2,785
Sulfur services	156,686	(434)	156,252	10,049	2,405	12,454
Indirect selling, general and administrative				(2,642)		(2,642)
Total	$ 625,249	$ (4,090)	$ 621,159	$ 13,304	$	$ 13,304

Our results of operations are discussed on a comparative basis below. There are certain items of income and expense which we do not allocate on a segment basis. These items, including equity in earnings (loss) of unconsolidated entities, interest expense, and indirect selling, general and administrative expenses, are discussed after the comparative discussion of our results within each segment.

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

Our total revenues before eliminations were $130.3 million for the three months ended June 30, 2009 compared to $310.6 million for the three months ended June 30, 2008, a decrease of $180.3 million, or 58%. Our operating income before eliminations was $11.0 million for the three months ended June 30, 2009 compared to $4.3 million for the three months ended June 30, 2008, an increase of $6.7 million, or 156%.

The results of operations are described in greater detail on a segment basis below.

Terminalling and Storage Segment

The following table summarizes our results of operations in our terminalling and storage segment.

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
	(In thousands)	
Revenues:		
Services	$ 11,039	$ 9,900
Products	9,020	11,895
Total revenues	20,059	21,795
Cost of products sold	7,918	10,269
Operating expenses	6,022	6,173
Selling, general and administrative expenses	104	13
Depreciation and amortization	2,596	2,301
	3,419	3,039
Other operating income	5,081	(14)
Operating income	$ 8,500	$ 3,025

Revenues. Our terminalling and storage revenues decreased $1.7 million, or 8%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. Service revenue increased $1.1 million due primarily to increased business activity at our terminals and increased throughput volumes at some of our terminals. Product revenue decreased $2.9 million primarily due to the sale of our traditional

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lubricant business including its inventory to Martin Resource Management in April 2009 in return for a service fee for lubricant volumes moved through our terminals. This decrease was offset by a 20% increase in sales volumes at our Mega Lubricants facility.

Cost of products sold. Our cost of products sold decreased $2.4 million, or 23%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This was primarily a result of the sale of our traditional lubricant business to Martin Resource Management in April 2009.

Operating expenses. Operating expenses decreased $0.2 million, or 2%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This decrease was a result of decreased repairs and maintenance and product hauling costs.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.1 million, or 700% for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. The increase was a result of increased bad debt expense.

Depreciation and amortization. Depreciation and amortization expenses increased $0.3 million, or 13%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This increase was primarily a result of our recent capital expenditures.

Other operating income. Other operating income for the three months ended June 30, 2009 consisted solely of a gain on the sale of our Mont Belvieu terminal on April 30, 2009

In summary, our terminalling operating income increased $5.5 million, or 181%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008.

Natural Gas Services Segment

The following table summarizes our results of operations in our natural gas services segment.

	Three Months Ended June 30,	
	2009	2008
	(In thousands)	
Revenues:		
NGLs	$ 69,972	$ 167,181
Natural gas	4,713	19,808
Non-cash mark-to-market adjustment of commodity derivatives	(1,891)	(3,995)
Gain (loss) on cash settlements of commodity derivatives	933	(2,053)
Other operating fees	1,102	1,084
Total revenues	74,829	182,025
Cost of products sold:		
NGLs	65,594	161,355
Natural gas	4,344	19,210
Total cost of products sold	69,938	180,565
Operating expenses	1,952	2,218
Selling, general and administrative expenses	1,476	1,187
Depreciation and amortization	1,115	962
	348	(2,907)
Other operating income		

Operating income (loss)	$ 348	$ (2,907)
NGLs Volumes (Bbls)	1,571	1,781
Natural Gas Volumes (Mmbtu)	1,655	1,902

Information above does not include activities relating to Waskom, PIPE, Matagorda and BCP investments.

	Three Months Ended June 30, 2009	2008
	(In thousands)	
Equity in Earnings of Unconsolidated Entities	$ 1,028	$ 4,372
Waskom:		
Plant Inlet Volumes (Mmcf/d)	227	272
Frac Volumes (Bbls/d)	7,215	10,943

Revenues. Our natural gas services revenues decreased $107.2 million, or 59% for the three months ended June 30, 2009 compared to the three months ended June 30, 2008 due to lower commodity prices.

For the three months ended June 30, 2009, NGL revenues decreased $97.2 million, or 58% and natural gas revenues decreased $15.1 million, or 76%. NGL sales volumes for the three months ended June 30, 2009 increased 28% and natural gas volumes decreased 13% compared to the same period of 2008. The decrease in NGL revenues is primarily due to falling commodity prices as our NGL average sales price per barrel decreased $65.27 or 68% and our natural gas average sales price per Mmbtu decreased $11.18, or 80% compared to the same period of 2008.

Our natural gas services segment utilizes derivative instruments to manage the risk of fluctuations in market prices for its anticipated sales of natural gas, condensate and NGLs. This activity is referred to as price risk management. For the three months ended June 30, 2009, 55% of our total natural gas volumes and 45% of our total NGL volumes were hedged as compared to 55% and 72%, respectively in 2008. The impact of price risk management and marketing activities decreased total natural gas and NGL revenues $1.0 million for the second quarter of 2009 compared to a decrease of $6.1 million in the same period of 2008. A $1.9 million decrease was attributable to a non-cash mark-to-market adjustments made to our derivative contracts which was offset by $0.9 million in gains recognized on cash settlements of our derivative contracts.

Costs of product sold. Our cost of products sold decreased $110.6 million, or 61%, for the three months ended June 30, 2009 compared to the same period of 2008. Of the decrease, $95.8 million relates to NGLs and $14.9 million relates to natural gas. The decrease in NGL cost of products sold is less than our decrease in NGL revenues as our NGL margins fell by $0.48 per barrel, or 15%. The decrease in natural gas cost of products sold was lower than the decrease in natural gas revenues which caused our Mmbtu margins to decrease by 29%. This decrease is primarily a result of a decline in commodity prices coupled with the Waskom plant being shut down for plant and fractionator expansion during the second quarter of 2009.

Operating expenses. Operating expenses decreased $0.3 million, or 12%, for the three months ended June 30, 2009 compared to the same period of 2008. This decrease was primarily a result of repairs and maintenance expense.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.3 million, or 24%, for the three months ended June 30, 2009 compared to the same period of 2008 due to increased compensation costs.

Depreciation and amortization. Depreciation and amortization increased $0.2 million, or 16%, for the three months ended June 30, 2009 compared to the same period of 2008 due to certain capital projects being placed in service.

In summary, our natural gas services operating income increased $3.3 million, or 112%, for the three months ended June 30, 2009 compared to the same period of 2008.

Equity in earnings of unconsolidated entities. Equity in earnings of unconsolidated entities was $1.0 million and $4.4 million for the three months ended June 30, 2009 and 2008, respectively, a decrease of 76%. This decrease is primarily a result of the Waskom plant being shut down for a plant and fractionator expansion during the second quarter of 2009. As a result, our inlet volumes and fractionation volumes decreased 17% and 55% respectively during the second quarter of 2009 as compared to 2008.

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Marine Transportation Segment

Marine Transportation Segment

The following table summarizes our results of operations in our marine transportation segment.

	Three Months Ended June 30,	
	2009	2008
	(In thousands)	
Revenues	$ 16,027	$ 20,308
Operating expenses	13,287	14,542
Selling, general and administrative expenses	346	266
Depreciation and amortization	3,266	2,948
	(872)	2,552
Other operating (loss)	(9)	
Operating income (loss)	$ (881)	$ 2,552

Revenues. Our marine transportation revenues decreased $4.3 million, or 21%, for the three months ended June 30, 2009, compared to the three months ended June 30, 2008. Our inland marine revenues decreased $3.7 million due to a decrease in fuel charges, down time for various vessels due to inspections and repairs, and decreased charter contract rates. Our offshore revenues decreased $0.6 million due to downtime associated with capital expenditures on offshore vessels.

Operating expenses. Operating expenses decreased $1.3 million, or 9%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This was primarily a result of a decrease in fuel costs which was offset by an increase in repair and maintenance expenses.

Selling, general, and administrative expenses. Selling, general and administrative expenses increased $0.1 million, or 30%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008.

Depreciation and Amortization. Depreciation and amortization increased $0.3 million, or 11%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This increase was primarily a result of capital expenditures made in the last twelve months.

Other operating income (loss). Other operating income for the three months ended June 30, 2009 consisted solely of a loss on the disposal of assets.

In summary, our marine transportation operating income decreased $3.4 million, or 134%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008.

Sulfur Services Segment

The following table summarizes our results of operations in our sulfur services segment.

	Three Months Ended June 30,	
	2009	2008
	(In thousands)	
Revenues	$ 19,343	$ 86,445
Cost of products sold	8,681	76,690
Operating expenses	3,888	4,727
Selling, general and administrative expenses	768	685
Depreciation and amortization	1,534	1,403

	4,472	2,940
Other operating income	1	
Operating income	$ 4,473	$ 2,940
Sulfur (long tons)	310.1	241.2
Fertilizer (long tons)	47.1	63.0
Sulfur Services Volumes (long tons)	357.2	304.2

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Revenues. Our sulfur services revenues decreased $67.1 million, or 78%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This decrease was primarily a result of an 81% decrease in our average sales price. The sales price decrease was primarily due to decreased market prices for our sulfur products.

Cost of products sold. Our cost of products sold decreased $68.0 million, or 89%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. Our margin per ton decreased 9%. This margin decrease was primarily driven by an overall weaker demand for our products as a result of the current economic recession.

Operating expenses. Our operating expenses decreased $0.8 million, or 18%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This decrease was a result of decreased fuel costs in our marine transportation expenses.

Selling, general, and administrative expenses. Our selling, general, and administrative expenses increased $0.1 million, or 12%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008.

Depreciation and amortization. Depreciation and amortization expense increased $0.1 million, or 9%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. This increase is a result of our new Neches Prillmax Priller coming online in March 2009.

In summary, our sulfur services operating income increased $1.5 million, or 52%, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008.

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

Our total revenues before eliminations were $289.2 million for the six months ended June 30, 2009 compared to $625.2 million for the six months ended June 30, 2008, a decrease of $336.0 million, or 54%. Our operating income before eliminations was $18.3 million for the six months ended June 30, 2009 compared to $13.3 million for the six months ended June 30, 2008, an increase of $5.0 million, or 38%.

The results of operations are described in greater detail on a segment basis below.

Terminalling and Storage Segment

The following table summarizes our results of operations in our terminalling and storage segment.

	Six Months Ended June 30,	
	2009	**2008**
	(In thousands)	
Revenues:		
Services	$ 21,680	$ 18,832
Products	22,583	23,325
Total revenues	44,263	42,157
Cost of products sold	20,023	20,191
Operating expenses	12,976	12,342
Selling, general and administrative expenses	159	34
Depreciation and amortization	5,096	4,442
	6,009	5,148
Other operating income	5,081	(14)
Operating income	$ 11,090	$ 5,134

Revenues. Our terminalling and storage revenues increased $2.1 million, or 5%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. Service revenue accounted for $2.8 million of this increase. The service revenue increase was primarily a result of increased business activity at our terminals and increased through put volumes at some of our terminals. Product revenue decreased $0.7 million primarily due to the sale of our traditional lubricant business including its inventory to Martin Resource Management in April 2009 in return for a service fee for lubricant volumes moved through our terminals. This decrease was offset by a 16 % increase in sales volumes at our Mega Lubricants facility.

Cost of products sold. Our cost of products increased $0.2 million, or 1%, for the six months ended June 30, 2008 compared to the six months ended June 30, 2007. The sale of our traditional lubricant business to Martin Resource Management in April 2009 negatively affected our cost of products sold but was offset by a 16% increase in sale volumes at our Mega Lubricants Facility.

Operating expenses. Operating expenses increased $0.6 million, or 5%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This increase was a result of increased salaries and related burden and product hauling costs related to increased activity at our existing terminals.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.1 million, or 368%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. The increase was a result of increased bad debt expense.

Depreciation and amortization. Depreciation and amortization increased $0.7 million, or 15% for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This increase was primarily a result of our recent capital expenditures.

Other operating income. Other operating income for the six months ended June 30, 2009 consisted solely of a gain on the sale of our Mont Belvieu terminal on April 30, 2009.

In summary, terminalling and storage operating income increased $6.0 million, or 116%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008.

Natural Gas Services Segment

The following table summarizes our results of operations in our natural gas services segment.

	Six Months Ended June 30,	
	2009	**2008**
	(In thousands)	
Revenues:		
NGLs	$ 153,778	$ 361,790
Natural gas	9,897	33,620
Non-cash mark-to-market adjustment of commodity derivatives	(2,156)	(5,112)
Gain (loss) on cash settlements of commodity derivatives	2,146	(2,997)
Other operating fees	2,030	1,816
Total revenues	165,695	389,117
Cost of products sold:		
NGLs	143,560	350,501
Natural gas	9,315	33,137
Total cost of products sold	152,875	383,638
Operating expenses	4,457	4,217
Selling, general and administrative expenses	3,300	2,413
Depreciation and amortization	2,234	1,939

	2,829	(3,090)
Other operating income		1
Operating income (loss)	$ 2,829	$ (3,089)

	Six Months Ended June 30, 2009	2008
	(In thousands)	
NGLs Volumes (Bbls)	3,851	4,578
Natural Gas Volumes (Mmbtu)	3,012	3,699
Information above does not include activities relating to Waskom, PIPE, Matagorda and BCP investments.		
Equity in Earnings of Unconsolidated Entities	$ 3,088	$ 7,882
Waskom:		
Plant Inlet Volumes (Mmcf/d)	237	265
Frac Volumes (Bbls/d)	9,349	10,494

Revenues. Our natural gas services revenues decreased $223.4 million, or 57% for the six months ended June 30, 2009 compared to the six months ended June 30, 2008 due to lower commodity prices.

For the six months ended June 30, 2009, NGL revenues decreased $208.0 million, or 58% and natural gas revenues decreased $23.7 million, or 71%. NGL sales volumes for the six months of 2009 increased by 1% and natural gas volumes decreased 18% compared to the same period of 2008. The decrease in NGL revenues is primarily due to falling commodity prices as our NGL average sales price per barrel decreased $45.64 or 58% and our natural gas average sales price per Mmbtu decreased $5.80, or 64% compared to the same period of 2008.

Our natural gas services segment utilizes derivative instruments to manage the risk of fluctuations in market prices for its anticipated sales of natural gas, condensate and NGLs. This activity is referred to as price risk management. For the six months ended June 30, 2009, 55% of our total natural gas volumes and 45% of our total NGL volumes were hedged as compared to 55% and 72%, respectively in 2008. Non-cash mark to market losses on our derivative contracts of $2.2 million offset by gains recognized on cash settlements of our derivative contracts of $2.2 million resulted in no impact on total natural gas and NGL revenues for the six months ended June 30, 2009 compared to a decrease of $8.1 million in the same period of 2008.

Costs of product sold. Our cost of products sold decreased $230.8 million, or 60%, for the six months ended June 30, 2009 compared to the same period of 2008. Of the decrease, $206.9 million relates to NGLs and $23.8 million relates to natural gas. The decrease in NGL cost of products sold is more than our decrease in NGL revenues as our NGL margins increased by $0.19 per barrel, or 8%. The percentage decrease in natural gas cost of products sold was higher than the percentage decrease in natural gas revenues which caused our Mmbtu margins to increase by 48%. This decrease is primarily a result of a decline in commodity prices coupled with the Waskom plant being shut down for plant and fractionator expansion during the second quarter of 2009.

Operating expenses. Operating expenses remained consistent for the six months ended June 30, 2009 compared to the same period of 2008.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.9 million, or 37%, for the six months ended June 30, 2009 compared to the same period of 2008 due to increased compensation costs.

Depreciation and amortization. Depreciation and amortization increased $0.3 million, or 15%, for the six months ended June 30, 2009 compared to the same period of 2008 due to certain capital projects being placed in service.

In summary, our natural gas services operating income increased $5.9 million, or 192%, for the six months ended June 30, 2009 compared to the same period of 2008.

Equity in earnings of unconsolidated entities. Equity in earnings of unconsolidated entities was $3.1 million and $7.9 million for the six months ended June 30, 2009 and 2008, respectively, a decrease of 61%. This decrease is primarily a result of the Waskom plant being shut down for a plant and fractionator expansion during the first half of 2009. As a result, our inlet volumes and fractionation volumes decreased 11% during the six months ending June 30, 2009 as compared to the same period in 2008.

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Marine Transportation Segment

Marine Transportation Segment

The following table summarizes our results of operations in our marine transportation segment.

	Six Months Ended June 30,	
	2009	2008
	(In thousands)	
Revenues	$ 33,270	$ 37,289
Operating expenses	25,495	27,317
Selling, general and administrative expenses	355	517
Depreciation and amortization	6,567	5,742
	853	3,713
Other operating income (loss)	(9)	139
Operating income	$ 844	$ 3,852

Revenues. Our marine transportation revenues decreased $4.0 million, or 11%, for the six months ended June 30, 2009, compared to the six months ended June 30, 2008. Our inland marine revenues decreased $3.2 million due to decrease in fuel charges, down time for various vessels due to inspections and repairs and decreased charter contract rates. Our offshore revenues decreased $0.8 million primarily due to downtime associated with capital expenditures on offshore vessels.

Operating expenses. Operating expenses decreased $1.8 million, or 7%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This was primarily a result of a decrease in fuel costs which was offset by an increase in repairs and maintenance expenses and wages and the related salary burden cost.

Selling, general, and administrative expenses. Selling, general and administrative expenses decreased $0.2 million, or 31%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This was primarily a result of the collection of certain bad debt expenses in 2009.

Depreciation and Amortization. Depreciation and amortization increased $0.8 million, or 14%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This increase was primarily a result of capital expenditures made in the last twelve months.

Other operating income (loss). Other operating income for the six months ended June 30, 2009 consisted solely of a losses on the disposal of assets. Other operating income for the six months ended June 30, 2009 consisted solely of a gains on the disposal of assets.

In summary, our marine transportation operating income decreased $3.0 million, or 78%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008.

Sulfur Services Segment

The following table summarizes our results of operations in our sulfur services segment.

	Six Months Ended June 30,	
	2009	2008
	(In thousands)	
Revenues	$ 45,929	$ 156,686
Cost of products sold	27,207	133,907
Operating expenses	7,741	8,559
Selling, general and administrative expenses	1,596	1,340

Depreciation and amortization	3,019	2,831
	6,366	10,049
Other operating income	1	
Operating income	$ 6,367	$ 10,049
Sulfur (long tons)	539.3	523.3
Fertilizer (long tons)	97.7	138.3
Sulfur (long tons)	637.0	661.6

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Revenues. Our sulfur services revenues decreased $110.8 million, or 71%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This decrease was primarily a result of a 70% decrease in our average sales price. The sales price decrease was primarily due to decreased market prices for our sulfur products.

Cost of products sold. Our cost of products sold decreased $106.7 million, or 80%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. Our margin per ton decreased 15%. This margin decrease was primarily driven by an overall weaker demand for our products as a result of the current economic recession.

Operating expenses. Our operating expenses decreased $0.8 million, or 9%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This decrease was a result of decreased fuel costs in our marine transportation expenses.

Selling, general, and administrative expenses. Our selling, general, and administrative expenses increased $0.3 million, or 19%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This is related to increases of $0.2 million and $0.1 million in salaries and bad debt expense, respectively.

Depreciation and amortization. Depreciation and amortization expense increased $0.2 million, or 7%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. This is a result of our Neches Prillmax Priller becoming operational in March 2009.

In summary, our sulfur operating income decreased $3.7 million, or 37%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008.

Statement of Operations Items as a Percentage of Revenues

Our cost of products sold, operating expenses, selling, general and administrative expenses, and depreciation and amortization as a percentage of revenues for the three months and six months ended June 30, 2009 and 2008 are as follows:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2009	**2008**	**2009**	**2008**
Revenues	100%	100%	100%	100%
Cost of products sold	67%	87%	70%	86%
Operating expenses	18%	9%	17%	8%
Selling, general and administrative expenses	3%	1%	3%	1%
Depreciation and amortization	7%	2%	6%	2%

Equity in Earnings of Unconsolidated Entities

For the three and six months ended June 30, 2009 and 2008 equity in earnings of unconsolidated entities relates to our unconsolidated interests in Waskom, Matagorda, PIPE and BCP.

Equity in earnings of unconsolidated entities was $1.0 million for the three months ended June 30, 2009 compared to $4.4 million for the three months ended June 30, 2008, a decrease of $3.4 million. This decrease is related to earnings received from Waskom, Matagorda, PIPE and BCP.

Equity in earnings of unconsolidated entities was $3.1 million for the six months ended June 30, 2009 compared to $7.9 million for the six months ended June 30, 2008, a decrease of $4.8 million. This decrease is related to earnings received from Waskom, Matagorda, PIPE and BCP.

Interest Expense

Our interest expense for all operations was $4.2 million for the three months ended June 30, 2009, compared to the $3.9 million for the three months ended June 30, 2008, an increase of $0.3 million, or 8%. This increase was primarily due to recognized increases in interest expense related to the difference between the fixed rate and the floating rate of interest on the mark-to-market interest rate swap and an increase in average debt outstanding.

Our interest expense for all operations was $8.9 million for the six months ended June 30, 2009, compared to the $8.6 million for the six months ended June 30, 2008, an increase of $0.3 million, or 3%. This increase was primarily due to recognized increases in interest expense related to the difference between the fixed rate and the floating rate of interest on the interest rate swap and an increase in average debt outstanding.

Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses were $1.4 million for the three months ended June 30, 2009 compared to $1.3 million for the three months ended June 30, 2008, an increase of $0.1 million, or 8%.

Indirect selling, general and administrative expenses were $2.9 million for the six months ended June 30, 2009 compared to $2.6 million for the six months ended June 30, 2008, an increase of $0.3 million, or 12%.

Martin Resource Management allocated to us a portion of its indirect selling, general and administrative expenses for services such as accounting, treasury, clerical billing, information technology, administration of insurance, engineering, general office expense and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. This allocation is based on the percentage of time spent by Martin Resource Management personnel that provide such centralized services. Under the omnibus agreement, the reimbursement amount with respect to indirect general and administrative and corporate overhead expenses was capped at $2.0 million. This cap expired on November 1, 2007. Effective January 1, 2008, the Conflicts Committee of our general partner approved a reimbursement amount for indirect expenses of $2.7 million for the year ended December 31, 2008. Martin Resource Management allocated indirect selling, general and administrative expenses of $0.9 million and $0.7 million for the three months ended June 30, 2009 and 2008, respectively, and $1.8 million and $1.3 million for the six months ended June 30, 2009 and 2008, respectively.

Liquidity and Capital Resources

Impact of Current Economic Crisis

We believe that cash generated from operations and our borrowing capacity under our credit facility will be sufficient to meet our working capital requirements, anticipated maintenance capital expenditures and scheduled debt payments in 2009. However, current economic conditions, including wide fluctuations in commodity prices and deteriorating credit markets, have created constraints on liquidity within the capital markets and the ability to obtain credit in the markets. Due to restrictions on liquidity within the capital markets and existing litigation at Martin Resource Management (See Item 5. Other Information) our ability to access the capital markets maybe constrained. Our near-term focus is to ensure we have sufficient liquidity to fund our growth programs, while continuing the present distribution rate to our unitholders. The current economic crisis has created a challenging operating environment for us to maintain our liquidity and operating cash flows at levels consistent with the recent past while maintaining the present distribution rate to our unitholders. We continue to evaluate our liquidity and capital resources and we have and will continue to consider sales of non-essential assets and other available options for additional liquidity. For example, in the second quarter of 2009 we sold the assets comprising the Mont Belvieu railcar unloading facility to Enterprise Products Operating LLC. See Note 15 Gain on Disposal of Assets.

We intend to move forward with our commercially supported internal growth projects. Our ability to access the capital markets to fund new projects in the future at prices that make the proposed projects accretive is likely to be limited. We may revise the timing and scope of other projects as necessary to adapt to existing economic conditions and the incremental benefits expected to accrue to our unitholders from our expansion activities are likely to be decreased by substantial cost of capital increases during this period.

In addition, if there is need to access the credit markets and the credit markets do not improve, we cannot assure you that we would be able to secure additional financing if needed, and, if such funds were available, whether the terms or conditions would be acceptable to us.

Finally, our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will depend upon our future operating performance, which is subject to certain risks. For example, the impact of the current economic crisis may significantly affect our customers, including their ability to satisfy amounts due to us on a timely basis. Please read Item 1A. Risk Factors of our Form 10-K for the year ended December 31, 2008, filed with the SEC on March 4, 2009, for a discussion of such risks.

Cash Flows and Capital Expenditures

For the six months ended June 30, 2009 cash increased $1.6 million as a result of $29.6 million provided by operating activities, $6.5 million used in investing activities and $21.5 million used in financing activities. For the six months ended June 30, 2008, cash increased $7.2 million as a result of $27.0 million provided by operating activities, $57.7 million used in investing activities and $37.8 million provided by financing activities.

For the six months ended June 30, 2009 our investing activities of $6.5 million consisted of capital expenditures, proceeds from sale of property, plant and equipment, return of investments from unconsolidated entities and investments in and distributions from unconsolidated entities. For the six months ended June 30, 2008 our investing activities of $57.7 million consisted of capital expenditures, acquisitions, proceeds from sale of property, plant and equipment, return of investments from unconsolidated entities and investments in and distributions from unconsolidated entities.

Generally, our capital expenditure requirements have consisted, and we expect that our capital requirements will continue to consist, of:

- maintenance capital expenditures, which are capital expenditures made to replace assets to maintain our existing operations and to extend the useful lives of our assets; and

- expansion capital expenditures, which are capital expenditures made to grow our business, to expand and upgrade our existing terminalling, marine transportation, storage and manufacturing facilities, and to construct new terminalling facilities, plants, storage facilities and new marine transportation assets.

For the six months ended June 30, 2009 and 2008, our capital expenditures for property and equipment were $25.4 million and $58.7 million, respectively.

As to each period:

- For the six months ended June 30, 2009, we spent $20.5 million for expansion and $4.9 million for maintenance. Our expansion capital expenditures were made in connection with construction projects associated with our terminalling and sulfur business. Our maintenance capital expenditures were primarily made in our marine transportation segment to extend the useful lives of our marine assets and in our terminalling segment.

- For the six months ended June 30, 2008, we spent $53.7 million for expansion and $5.0 million for maintenance. Our expansion capital expenditures were made in connection with assets acquired in the Stanolind acquisition, marine vessel purchases and conversions and construction projects associated with our terminalling business. Our maintenance capital expenditures were primarily made in our marine transportation segment for routine dry dockings of our vessels pursuant to the United States Coast Guard requirements.

For the six months ended June 30, 2009, our financing activities consisted of cash distributions paid to common and subordinated unitholders of $23.7 million, payments of long term debt to financial lenders of $56.9 million and borrowings of long-term debt under our credit facility of $59.1 million.

For the six months ended June 30, 2008, our financing activities consisted of cash distributions paid to common and subordinated unitholders of $22.2 million, payments of long term debt to financial lenders of $100.8 million and borrowings of long-term debt under our credit facility of $160.8 million.

We made net investments in (received distributions from) unconsolidated entities of $1.0 million and $(0.1) million during the six months ended June 30, 2009 and 2008, respectively. The net investment in unconsolidated entities includes $2.3 million and $1.9 million of expansion capital expenditures in the six months ended June 30, 2009 and 2008, respectively.

Capital Resources

Historically, we have generally satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and borrowings. We expect our primary sources of funds for short-term liquidity needs will be cash flows from operations and borrowings under our credit facility.

As of June 30, 2009, we had $297.2 million of outstanding indebtedness, consisting of outstanding borrowings of $167.2 million under our revolving credit facility and $130.0 million under our term loan facility.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2009 is as follows (dollars in thousands):

		Payment due by period			
Type of Obligation	Total Obligation	Less than One Year	1-3 Years	3-5 Years	Due Thereafter
Long-Term Debt					
Revolving credit facility	$ 167,200	$	$ 167,200	$	$
Term loan facility	130,000		130,000		
Other					
Non-competition agreements	350	150	100	100	
Operating leases	25,249	4,291	10,666	4,386	5,906
Interest expense(1)					
Revolving Credit Facility	11,106	8,126	2,980		
Term loan facility	10,667	7,805	2,862		
Other					
Total contractual cash obligations	$ 344,572	$ 20,372	$ 313,808	$ 4,486	$ 5,906

(1) Interest commitments are estimated using our current interest rates for the respective credit agreements over their remaining terms.

Letter of Credit. At June 30, 2009, we had outstanding irrevocable letters of credit in the amount of $2.1 million which were issued under our revolving credit facility.

Off Balance Sheet Arrangements. We do not have any off-balance sheet financing arrangements.

Description of Our Credit Facility

On November 10, 2005, we entered into a new $225.0 million multi-bank credit facility comprised of a $130.0 million term loan facility and a $95.0 million revolving credit facility, which includes a $20.0 million letter of credit sub-limit. Our credit facility also includes procedures for additional financial institutions to become revolving lenders, or for any existing revolving lender to increase its revolving commitment, subject to a maximum of $100.0 million for all such increases in revolving commitments of new or existing revolving lenders. Effective June 30, 2006, we increased our revolving credit facility $25.0 million resulting in a committed $120.0 million revolving credit facility. Effective December 28, 2007, we increased our revolving credit facility $75.0 million resulting in a committed $195.0 million revolving credit facility. The revolving credit facility is used for ongoing working capital needs and general partnership purposes, and to finance permitted investments, acquisitions and capital expenditures. Under the amended and restated credit facility, as of June 30, 2009, we had $167.2 million outstanding under the revolving credit facility and $130.0 million outstanding under the term loan facility. As of June 30, 2009, irrevocable letters of credit issued under our credit facility totaled $2.1 million. As of June 30, 2009, we had $25.7 million available under our revolving credit facility.

Draws made under our credit facility are normally made to fund acquisitions and for working capital requirements. During the current fiscal year, draws on our credit facilities have ranged from a low of $285.0 million to a high of $315.0 million. As of June 30, 2009, we had $25.7 million available for working capital, internal expansion and acquisition activities under our credit facility.

Our obligations under the credit facility are secured by substantially all of our assets, including, without limitation, inventory, accounts receivable, marine vessels, equipment, fixed assets and the interests in our operating subsidiaries and equity method investees. We may prepay all amounts outstanding under this facility at any time without penalty.

Indebtedness under the credit facility bears interest at either LIBOR plus an applicable margin or the base prime rate plus an applicable margin. The applicable margin for revolving loans that are LIBOR loans ranges from 1.50% to 3.00% and the applicable margin for revolving loans that are base prime rate loans ranges from 0.50% to 2.00%. The applicable margin for term loans that are LIBOR loans ranges from 2.00% to 3.00% and the applicable margin for term loans that are base prime rate loans ranges from 1.00% to 2.00%. The applicable margin for existing LIBOR borrowings is 2.00%. Effective July 1, 2009, the applicable margin for existing LIBOR borrowings will remain at 2.00%. As a result of our leverage ratio test, effective October 1, 2009, the applicable margin for existing LIBOR borrowings will also remain at 2.00%. We incur a commitment fee on the unused portions of the credit facility.

Effective October 2008, we entered into an interest rate swap that swaps $40.0 million of floating rate to fixed rate. The fixed rate cost is 2.820% plus our applicable LIBOR borrowing spread. Effective April 2009, we entered into two subsequent swaps to lower our effective fixed rate to 2.580% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap are accounted for using mark-to-market accounting. The second subsequent swap is accounted for using hedge accounting. Each of the swaps matures in October, 2010.

Effective January 2008, we entered into an interest rate swap that swaps $25.0 million of floating rate to fixed rate. The fixed rate cost is 3.400% plus our applicable LIBOR borrowing spread. Effective April 2009, we entered into two subsequent swaps to lower our effective fixed rate to 3.050% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap are accounted for using mark-to-market accounting. The second subsequent swap is accounted for using hedge accounting. Each of the swaps matures in January, 2010.

Effective September 2007, we entered into an interest rate swap that swaps $25.0 million of floating rate to fixed rate. The fixed rate cost is 4.605% plus our applicable LIBOR borrowing spread. Effective March 2009, we entered into two subsequent swaps to lower our effective fixed rate to 4.305% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap are accounted for using mark-to-market accounting. The second subsequent swap is accounted for using hedge accounting. Each of the swaps matures in September, 2010.

Effective November 2006, we entered into an interest rate swap that swaps $40.0 million of floating rate to fixed rate. The fixed rate cost is 4.82% plus our applicable LIBOR borrowing spread. Effective March 2009, we entered into two subsequent swaps to lower our effective fixed rate to 4.37% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap are accounted for using mark-to-market accounting. The second subsequent swap is accounted for using hedge accounting. Each of the swaps matures in December, 2009.

Effective November 2006, we entered into an interest rate swap that swaps $30.0 million of floating rate to fixed rate. The fixed rate cost is 4.765% plus our applicable LIBOR borrowing spread. Effective March 2009, we entered a subsequent swap to lower our effective fixed rate to 4.325% plus our applicable LIBOR borrowing spread. These interest rate swaps which mature in March, 2010 are not accounted for using hedge accounting.

Effective March 2006, we entered into an interest rate swap that swaps $75.0 million of floating rate to fixed rate. The fixed rate cost is 5.25% plus our applicable LIBOR borrowing spread. Effective February 2009, we entered into two subsequent swaps to lower our effective fixed rate to 5.10% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap are accounted for using mark-to-market accounting. The second subsequent swap is accounted for using hedge accounting. Each of the swaps matures in November, 2010.

In addition, the credit facility contains various covenants, which, among other things, limit our ability to: (i) incur indebtedness; (ii) grant certain liens; (iii) merge or consolidate unless we are the survivor; (iv) sell all or substantially all of our assets; (v) make certain acquisitions; (vi) make certain investments; (vii) make certain capital expenditures; (viii) make distributions other than from available cash; (ix) create obligations for some lease payments; (x) engage in transactions with affiliates; (xi) engage in other types of business; and (xii) our joint ventures to incur indebtedness or grant certain liens.

The credit facility also contains covenants, which, among other things, require us to maintain specified ratios of: (i) minimum net worth (as defined in the credit facility) of $75.0 million plus 50% of net proceeds from equity issuances after November 10, 2005; (ii) EBITDA (as defined in the credit facility) to interest expense of not less than 3.0 to 1.0 at the end of each fiscal quarter; (iii) total funded debt to EBITDA of not more than 4.75 to 1.00 for each fiscal quarter; and (iv) total secured funded debt to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter. We are in compliance with the covenants contained in the credit facility as of June 30, 2009.

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls our general partner, the lenders under our credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, an event of default by Martin Resource Management under its credit facility could independently result in an event of default under our credit facility if it is deemed to have a material adverse effect on us. Any event of default and corresponding acceleration of outstanding balances under our credit facility could require us to refinance such indebtedness on unfavorable terms and would have a material adverse effect on our financial condition and results of operations as well as our ability to make distributions to unitholders.

On November 10 of each year, commencing with November 10, 2006, we must prepay the term loans under the credit facility with 75% of Excess Cash Flow (as defined in the credit facility), unless its ratio of total funded debt to EBITDA is less than 3.00 to 1.00. No prepayments under the term loan were required to be made through June 30, 2009. If we receive greater than $15.0 million from the incurrence of indebtedness other than under the credit facility, we must prepay indebtedness under the credit facility with all such proceeds in excess of $15.0 million. Any such prepayments are first applied to the term loans under the credit facility. We must prepay revolving loans under the credit facility with the net cash proceeds from any issuance of its equity. We must also prepay indebtedness under the credit facility with the proceeds of certain asset dispositions. Other than these mandatory prepayments, the credit facility requires interest only payments on a quarterly basis until maturity. All outstanding principal and unpaid interest must be paid by November 10, 2010. The credit facility contains customary events of default, including, without limitation, payment defaults, cross-defaults to other material indebtedness, bankruptcy-related defaults, change of control defaults and litigation-related defaults.

As of August 4, 2009, our outstanding indebtedness includes $300.6 million under our credit facility.

Seasonality

A substantial portion of our revenues are dependent on sales prices of products, particularly NGLs and fertilizers, which fluctuate in part based on winter and spring weather conditions. The demand for NGLs is strongest during the winter heating season. The demand for fertilizers is strongest during the early spring planting season. However, our terminalling and storage and marine transportation businesses and the molten sulfur business are typically not impacted by seasonal fluctuations. We expect to derive a majority of our net income from our terminalling and storage, marine transportation and sulfur businesses. Therefore, we do not expect that our overall net income will be impacted by seasonality factors. However, extraordinary weather events, such as hurricanes, have in the past, and could in the future, impact our terminalling and storage and marine transportation businesses. For example, Hurricanes Katrina and Rita in the third quarter of 2005 adversely impacted operating expenses and the four hurricanes that impacted the Gulf of Mexico and Florida in the third quarter of 2004 adversely impacted our terminalling and storage and marine transportation business s revenues.

Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the six months ended June 30, 2009 and 2008. However, inflation remains a factor in the United States economy and could increase our cost to acquire or replace property, plant and equipment as well as our labor and supply costs. We cannot assure you that we will be able to pass along increased costs to our customers.

Increasing energy prices could adversely affect our results of operations. Diesel fuel, natural gas, chemicals and other supplies are recorded in operating expenses. An increase in price of these products would increase our operating expenses which could adversely affect net income. We cannot assure you that we will be able to pass along increased operating expenses to our customers.

Environmental Matters

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We incurred no material environmental costs, liabilities or expenditures to mitigate or eliminate environmental contamination during the three and six months ended June 30, 2009 or 2008.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk. We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. Under our hedging policy, we monitor and manage the commodity market risk associated with the commodity risk exposure of Prism Gas. In addition, we are focusing on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

We use derivatives to manage the risk of commodity price fluctuations**.** These outstanding contracts expose us to credit loss in the event of nonperformance by the counterparties to the agreements. We have incurred no losses associated with counterparty nonperformance on derivative contracts.

On all transactions where we are exposed to counterparty risk, we analyze the counterparty s financial condition prior to entering into an agreement, and have established a maximum credit limit threshold pursuant to our hedging policy, and monitor the appropriateness of these limits on an ongoing basis. We have agreements with three counterparties containing collateral provisions. Based on those current agreements, cash deposits are required to be posted whenever the net fair value of derivatives associated with the individual counterparty exceed a specific threshold. If this threshold is exceeded, cash is posted by us if the value of derivatives is a liability to us. As of June 30, 2009, we have no cash collateral deposits posted with counterparties.

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of gathering, processing and sales activities. Our gathering and processing revenues are earned under various contractual arrangements with gas producers. Gathering revenues are generated through a combination of fixed-fee and index-related arrangements. Processing revenues are generated primarily through contracts which provide for processing on percent-of-liquids (POL) and percent-of-proceeds (POP) basis. We have entered into hedging transactions through 2010 to protect a portion of our commodity exposure from these contracts. These hedging arrangements are in the form of swaps for crude oil, natural gas, and natural gasoline.

Based on estimated volumes, as of June 30, 2009, we had hedged approximately 56% and 27% of our commodity risk by volume for 2009 and 2010, respectively. We anticipate entering into additional commodity derivatives on an ongoing basis to manage our risks associated with these market fluctuations, and will consider using various commodity derivatives, including forward contracts, swaps, collars, futures and options, although there is no assurance that we will be able to do so or that the terms thereof will be similar to our existing hedging arrangements.

Hedging Arrangements in Place
As of June 30, 2009

Year	Commodity Hedged	Volume	Type of Derivative	Basis Reference
2009	Natural Gas	30,000 MMBTU/Month	Natural Gas Swap ($9.025)	Columbia Gulf
2009	Condensate & Natural Gasoline	3,000 BBL/Month	Crude Oil Swap ($69.08)	NYMEX
2009	Natural Gasoline	3,000 BBL/Month	Crude Oil Swap ($70.90)	NYMEX
2009	Condensate	1,000 BBL/Month	Crude Oil Swap ($70.45)	NYMEX
2009	Natural Gasoline	2,000 BBL/Month	Natural Gasoline Swap ($86.42)	Mt. Belvieu (Non-TET)
2010	Condensate	2,000 BBL/Month	Crude Oil Swap ($69.15)	NYMEX
2010	Natural Gasoline	3,000 BBL/Month	Crude Oil Swap ($72.25)	NYMEX
2010	Condensate	1,000 BBL/Month	Crude Oil Swap ($104.80)	NYMEX
2010	Natural Gasoline	1,000 BBL/Month	Natural Gasoline Swap ($94.14)	Mt. Belvieu (Non-TET)

Our principal customers with respect to Prism Gas natural gas gathering and processing are large, natural gas marketing services, oil and gas producers and industrial end-users. In addition, substantially all of our natural gas and NGL sales are made at market-based prices. Our standard gas and NGL sales contracts contain adequate assurance provisions which allows for the suspension of deliveries, cancellation of agreements or discontinuance of deliveries to the buyer unless the buyer provides security for payment in a form satisfactory to us.

Interest Rate Risk. We are exposed to changes in interest rates as a result of our credit facility, which had a weighted-average interest rate of 5.36% as of June 30, 2009. We had a total of $300.6 million of indebtedness outstanding under our credit facility as of August 4, 2009 of which $65.6 million was unhedged floating rate debt. Based on the amount of unhedged floating rate debt owed by us on June 30, 2009, the impact of a 1% increase in interest rates on this amount of debt would result in an increase in interest expense and a corresponding decrease in net income of approximately $0.7 million annually.

We have entered into interest rate protection agreements to manage our interest rate risk exposure by fixing a portion of the interest expense we pay on our long-term debt under our credit facility. Continued disruption in banking markets could affect whether our counterparties of interest rate protection agreements are able to honor their agreements. If the counterparties fail to honor their commitments, we could experience higher interest rates, which could have a material adverse effect on our business, financial condition and results of operations. In addition, if the counterparties fail to honor their commitments, we also may be required to replace such interest rate protection agreements with new interest rate protection agreements, and such replacement interest rate protection agreements may be at higher rates than our current interest rate protection agreements.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934, as amended (the Exchange Act), we, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of our general partner, carried out an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report, to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

There were no changes in our internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, we are subject to certain legal proceedings claims and disputes that arise in the ordinary course of our business. Although we cannot predict the outcomes of these legal proceedings, we do not believe these actions, in the aggregate, will have a material adverse impact on our financial position, results of operations or liquidity.

In addition to the foregoing, as a result of an inspection by the U.S. Coast Guard of our tug Martin Explorer at the Freeport Sulfur Dock Terminal in Tampa, Florida, we have been informed that an investigation has been commenced concerning a possible violation of the Act to Prevent Pollution from Ships, 33 USC 1901, et. seq., and the MARPOL Protocol 73/78. In connection with this matter, two employees of Martin Resource Management who provide services to us were served with grand jury subpoenas during the fourth quarter of 2007. In addition, in April of 2009, an additional grand jury subpoena was issued pertaining to the provision of certain documents relating to the Martin Explorer and its crew. We are cooperating with the investigation and, as of the date of this report, no formal charges, fines and/or penalties have been asserted against us.

Item 1A. Risk Factors

There has been no material changes in our risk factors from those disclosed in Item 1A. Risk Factors of our Form 10-K for the year ended December 31, 2008 filed with the SEC on March 4, 2009. Please see Item 1A. Risk Factors of our Form 10-K for the year ended December 31, 2008 filed with the SEC on March 4, 2009.

Item 5. Other Information

Certain Other Information. On May 2, 2008, we received a copy of a petition filed in the District Court of Gregg County, Texas (the Court) by Scott D. Martin (the Plaintiff) against Ruben S. Martin, III (the Defendant) with respect to certain matters relating to Martin Resource Management. The Plaintiff and the Defendant are executive officers of Martin Resource Management and our general partner, the Defendant is a director of both Martin Resource Management and our general partner, and the Plaintiff is a director of Martin Resource Management. The lawsuit alleged that the Defendant breached a settlement agreement with the Plaintiff concerning certain Martin Resource Management matters and that the Defendant breached fiduciary duties allegedly owed to the Plaintiff in connection with their respective ownership and other positions with Martin Resource Management. Prior to the trial of this lawsuit, the Plaintiff dropped his claims against the Defendant relating to the breach of fiduciary duty allegations. We are not a party to the lawsuit and the lawsuit does not assert any claims (i) against us, (ii) concerning our governance or operations or (iii) against the Defendant with respect to his service as an officer or director of our general partner.

In May 2009, the lawsuit went to trial and on June 18, 2009, the Court entered a judgment (the Judgment) with respect to the lawsuit as further described below. In connection with the Judgment, the Defendant has advised us that he has filed a motion for new trial, a motion for judgment notwithstanding the verdict and a notice of appeal. In addition, on June 22, 2009, the Plaintiff filed a notice of appeal with the Court indicating his intent to appeal the Judgment. The Defendant has further advised us that on June 30, 2009 he posted a cash deposit in lieu of a bond and the judge has ruled that as a result of such deposit, the enforcement of any of the provisions in the Judgment is stayed until the matter is resolved on appeal. Accordingly, during the pendancy of the of the appeal process, no change in the makeup of the Martin Resource Management Board of Directors is expected.

The Judgment awarded the Plaintiff monetary damages in the approximate amount of $3.2 million, attorney s fees of approximately $1.6 million and interest. In addition, the Judgment grants specific performance and provides that the Defendant is to (i) transfer one share of his Martin Resource Management common stock to the Plaintiff, (ii) take such actions, including the voting of any Martin Resource Management shares which the Defendant owns, controls or otherwise has the power to vote, as are necessary to change the composition of the Board of Directors of Martin Resource Management from a five-person board, currently consisting of the Defendant and the Plaintiff as well as Wes Skelton, Don Neumeyer, and Bob Bondurant (executive officers of Martin Resource Management and the Partnership), to a four-person board to consist of the Defendant and his designee and the Plaintiff and his designee, and (iii) take such actions as are necessary to change the trustees of the Martin Resource Management Employee Stock Ownership Trust (the MRMC ESOP Trust), currently consisting of the Defendant, the Plaintiff and Wes Skelton, to just the Defendant and the Plaintiff. The Judgment is directed solely at the Defendant and is not binding on any other officer, director or shareholder of Martin Resource Management or any trustee of a trust owning Martin Resource Management shares. The Judgment with respect to (ii) above will terminate on February 17, 2010, and with respect to (iii) above on the 30th day after the election by the Martin Resource Management shareholders of the first successor Martin Resource Management board after February 17, 2010. However, any enforcement of the Judgment is stayed pending resolution of the appeal relating to it.

On September 5, 2008, the Plaintiff and one of his affiliated partnerships (the SDM Plaintiffs), on behalf of themselves and derivatively on behalf of Martin Resource Management, filed suit in a Harris County, Texas district court against Martin Resource Management, the Defendant, Robert Bondurant, Donald R. Neumeyer and Wesley Skelton, in their capacities as directors of Martin Resource Management (the MRMC Director Defendants), as well as 35 other officers and employees of Martin Resource Management (the Other MRMC Defendants). In addition to their respective positions with Martin Resource Management, Robert Bondurant, Donald Neumeyer and Wesley Skelton are officers of our general partner. We are not a party to this lawsuit, and it does not assert any claims (i) against us, (ii) concerning our governance or operations or (iii) against the MRMC Director Defendants or Other MRMC Defendants with respect to their service to us.

The SDM Plaintiffs allege, among other things, that the MRMC Director Defendants have breached their fiduciary duties owed to Martin Resource Management and the SDM Plaintiffs, entrenched their control of Martin Resource Management and diluted the ownership position of the SDM Plaintiffs and certain other minority shareholders in Martin Resource Management, and engaged in acts of unjust enrichment, excessive compensation, waste, fraud and conspiracy with respect to Martin Resource Management. The SDM Plaintiffs seek, among other things, to rescind the June 2008 issuance by Martin Resource Management of shares of its common stock under its 2007 Long-Term Incentive Plan to the Other MRMC Defendants, remove the MRMC Director Defendants as officers and directors of Martin Resource Management, prohibit the Defendant, Wesley Skelton and Robert Bondurant from serving as trustees of the MRMC Employee Stock Ownership Plan, and place all of the Martin Resource Management common shares owned or controlled by the Defendant in a constructive trust that prohibits him from voting those shares. The SDM Plaintiffs have amended their Petition to eliminate their claims regarding rescission of the issue by Martin Resource Management of shares of its common stock to the MRMC Employee Stock Ownership Plan. The Court abated this lawsuit on July 13, 2009 until a mandamus pending before the Texas Supreme Court dealing with matters at issue in the lawsuit is resolved.

The lawsuits described above are in addition to (i) a separate lawsuit filed in July 2008 in a Gregg County, Texas district court by the daughters of the Defendant against the Plaintiff, both individually and in his capacity as trustee of the Ruben S. Martin, III Dynasty Trust, which suit alleges, among other things, that the Plaintiff has engaged in self-dealing in his capacity as a trustee under the trust, which holds shares of Martin Resource Management common stock, and has breached his fiduciary duties owed to the plaintiffs, and who are beneficiaries of such trust, and (ii) a separate lawsuit filed in October 2008 in the United States District Court for the Eastern District of Texas by Angela Jones Alexander against the Defendant and Karen Yost in their capacities as a former trustee and a trustee, respectively, of the R.S. Martin Jr. Children Trust No. One (f/b/o Angela Santi Jones), which holds shares of Martin Resource Management common stock, which suit alleges, among other things that the Defendant and Karen Yost breached the fiduciary duties owed to the plaintiff, who is the beneficiary of such trust, and seeks to remove Karen Yost as the trustee of such trust. With respect to the lawsuit described in (i) above, it should be noted that the Plaintiff has resigned as a trustee of the Ruben S. Martin, III Dynasty Trust. With respect to the lawsuit described in (ii) above, Angela Jones Alexander has amended her claims to include her grandmother, Margaret Martin, as a party.

On September 24, 2008, Martin Resource Management removed Plaintiff as a director of the general partner of the Partnership. Such action was taken as a result of the collective effect of Plaintiff s then recent activities, which the Board of Directors of Martin Resource Management determined were detrimental to both Martin Resource Management and the Partnership. The Plaintiff does not serve on any committees of the board of directors of our general partner. The position on the board of directors of our general partner vacated by the Plaintiff may be filled in accordance with the existing procedures for replacement of a departing director utilizing the Nominations Committee of the board of directors of the general partner of the Partnership. This position on the board of directors has not been filled as of August 5, 2009.

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Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report and is incorporated herein by reference.

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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.

Martin Midstream Partners L.P.

By: Martin Midstream GP LLC
It s General Partner

Date: August 5, 2009

By: /s/ Ruben S. Martin

Ruben S. Martin
President and Chief Executive Officer

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INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
3.1	Certificate of Limited Partnership of Martin Midstream Partners L.P. (the Partnership), dated June 21, 2002 (filed as Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.2	First Amended and Restated Agreement of Limited Partnership of the Partnership, dated November 6, 2002 (filed as Exhibit 3.1 to the Partnership s Current Report on Form 8-K, filed November 19, 2002, and incorporated herein by reference).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of the Partnership, dated November 1, 2007 (filed as Exhibit 3.1 to the Partnership s Current Report on Form 8-K, filed November 2, 2007, and incorporated herein by reference).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of the Partnership, dated effective January 1, 2007 (filed as Exhibit 3.1 to the Partnership s Current Report on Form 8-K, filed April 7, 2008, and incorporated herein by reference).
3.5	Certificate of Limited Partnership of Martin Operating Partnership L.P. (the Operating Partnership), dated June 21, 2002 (filed as Exhibit 3.3 to the Partnership s Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.6	Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated November 6, 2002 (filed as Exhibit 3.2 to the Partnership s Current Report on Form 8-K, filed November 19, 2002, and incorporated herein by reference).
3.7	Certificate of Formation of Martin Midstream GP LLC (the General Partner), dated June 21, 2002 (filed as Exhibit 3.5 to the Partnership s Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.8	Limited Liability Company Agreement of the General Partner, dated June 21, 2002 (filed as Exhibit 3.6 to the Partnership s Registration Statement on Form S-1 (Reg. No. 33-91706), filed July 1, 2002, and incorporated herein by reference).
3.9	Certificate of Formation of Martin Operating GP LLC (the Operating General Partner), dated June 21, 2002 (filed as Exhibit 3.7 to the Partnership s Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.10	Limited Liability Company Agreement of the Operating General Partner, dated June 21, 2002 (filed as Exhibit 3.8 to the Partnership s Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
4.1	Specimen Unit Certificate for Common Units (contained in Exhibit 3.2).
4.2	Specimen Unit Certificate for Subordinated Units (filed as Exhibit 4.2 to Amendment No. 4 to the Partnership s Registration Statement on Form S-1 (Reg. No. 333-91706), filed October 25, 2002, and

incorporated herein by reference).

31.1*	Certifications of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certifications of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be filed.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be filed.
99.1*	Balance Sheets as of June 30, 2009 (unaudited) and December 31, 2008 (audited) of the General Partner.

* Filed or furnished herewith