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

FORM 10-Q

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

For the quarterly period ended June 30, 2011

or

☐ **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: 001-33303

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1000 Louisiana St, Suite 4300, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 584-1000
(Registrant’s telephone number, including area code**)**

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 £ No £.

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

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

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

As of August 1, 2011, there were 84,756,009 Common Units and 1,729,715 General Partner Units outstanding.

PART I—FINANCIAL INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we", "us", "our" or the "Partnership") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Part II-Other Information, Item 1A. Risk Factors" of this Quarterly Report on Form 10-Q (this "Quarterly Report"), as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL") and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems and NGL supplies to our logistics and marketing facilities;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in "Part II–Other Information, Item 1A. Risk Factors" of this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2010 ("Annual Report") and our reports and registration statements filed from time to time with the Securities and Exchange Commission.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Part II–Other Information, Item 1A. Risk Factors" in this Quarterly Report and in our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Quarterly Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 gallons)
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
gal	Gallons
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange

Price Index Definitions	
IF-NGPL MC	Inside FERC Gas Market Report, Natural Gas Pipeline, Mid-Continent
IF-PB	Inside FERC Gas Market Report, Permian Basin
IF-WAHA	Inside FERC Gas Market Report, West Texas WAHA
NY-WTI	NYMEX, West Texas Intermediate Crude Oil
OPIS-MB	Oil Price Information Service, Mont Belvieu, Texas

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	June 30, 2011	December 31, 2010
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 73.1	$ 76.3
Trade receivables, net of allowances of $7.7 million	495.5	466.1
Inventory	69.8	50.3
Assets from risk management activities	22.5	25.2
Other current assets	20.8	2.9
Total current assets	681.7	620.8
Property, plant and equipment, at cost	3,465.2	3,299.5
Accumulated depreciation	(891.4)	(804.3)
Property, plant and equipment, net	2,573.8	2,495.2
Long-term assets from risk management activities	13.2	18.9
Investment in unconsolidated affiliate	20.6	15.2
Other long-term assets	39.1	36.3
Total assets	$ 3,328.4	$ 3,186.4
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable to third parties	$ 326.7	$ 250.5
Accounts payable to Targa Resources Corp.	53.9	51.4
Accrued liabilities	300.2	273.7
Liabilities from risk management activities	56.9	34.2
Total current liabilities	737.7	609.8
Long-term debt	1,176.5	1,445.4
Long-term liabilities from risk management activities	44.5	32.8
Deferred income taxes	10.2	8.7
Other long-term liabilities	43.0	40.6
Commitments and contingencies (see Note 11)		
Owners' equity:		
Common unitholders (84,756,009 and 75,545,409 units issued and outstanding as of June 30, 2011 and December 31, 2010)	1,221.5	935.3
General partner (1,729,715 and 1,541,744 units issued and outstanding as of June 30, 2011 and December 31, 2010)	23.5	15.1
Accumulated other comprehensive income (loss)	(68.2)	(30.6)
	1,176.8	919.8
Noncontrolling interests in subsidiaries	139.7	129.3
Total owners' equity	1,316.5	1,049.1
Total liabilities and owners' equity	$ 3,328.4	$ 3,186.4

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 1,725.4	$ 1,237.6	$ 3,339.9	$ 2,721.4
Costs and expenses:				
Product purchases	1,477.2	1,057.8	2,877.8	2,355.7
Operating expenses	71.6	62.0	137.6	124.2
Depreciation and amortization expenses	44.5	43.0	87.2	85.0
General and administrative expenses	33.2	28.2	64.9	53.2
Income from operations	98.9	46.6	172.4	103.3
Other income (expense):				
Interest expense from affiliate	-	(7.8)	-	(21.3)
Interest expense allocated from Parent	-	(2.1)	-	(4.2)
Other interest expense, net	(27.2)	(17.7)	(54.6)	(33.1)
Equity in earnings of unconsolidated investment	1.3	2.4	3.0	2.7
Gain (loss) on mark-to-market derivative instruments	(3.2)	2.4	(3.2)	27.8
Other	0.1	-	(0.1)	-
Income before income taxes	69.9	23.8	117.5	75.2
Income tax expense:				
Current	(0.8)	(1.0)	(2.2)	(1.8)
Deferred	(1.1)	0.1	(1.5)	(0.6)
	(1.9)	(0.9)	(3.7)	(2.4)
Net income	68.0	22.9	113.8	72.8
Less: Net income attributable to noncontrolling interests	12.8	6.2	20.7	13.5
Net income attributable to Targa Resources Partners LP	$ 55.2	$ 16.7	$ 93.1	$ 59.3
Net income (loss) attributable to predecessor operations	$ -	$ (3.1)	$ -	$ 27.0
Net income attributable to general partner	8.9	3.9	16.5	7.0
Net income attributable to limited partners	46.3	15.9	76.6	25.3
Net income attributable to Targa Resources Partners LP	$ 55.2	$ 16.7	$ 93.1	$ 59.3
Net income per limited partner unit - basic and diluted	$ 0.55	$ 0.23	$ 0.92	$ 0.37
Weighted average limited partner units outstanding - basic and diluted	84.8	68.0	83.5	67.7

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(Unaudited) (In millions)			
Net income	$ 68.0	$ 22.9	$ 113.8	$ 72.8
Other comprehensive income:				
Commodity hedging contracts:				
Change in fair value	4.4	26.6	(56.9)	60.2
Settlements reclassified to revenues	11.9	(3.2)	16.5	(0.2)
Interest rate hedges:				
Change in fair value	(2.2)	(10.1)	(1.9)	(16.8)
Settlements reclassified to interest expense, net	2.2	3.4	4.6	5.0
Other comprehensive income (loss)	16.3	16.7	(37.7)	48.2
Comprehensive income (loss)	84.3	39.6	76.1	121.0
Less: Comprehensive income attributable to noncontrolling interests	12.8	6.2	20.7	13.5
Comprehensive income (loss) attributable to Targa Resources Partners LP	$ 71.5	$ 33.4	$ 55.4	$ 107.5

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENT OF CHANGES IN OWNERS' EQUITY

	Limited Partner		General Partner		Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Units	Amount	Units	Amount			
	(Unaudited) (In millions)						
Balance, December 31, 2010	75.5	$ 935.3	1.5	$ 15.1	$ (30.6)	$ 129.3	$ 1,049.1
Compensation on equity grants	-	0.8	-	-	-	-	0.8
Proceeds from equity offerings	9.2	298.0	0.2	6.3	-	-	304.3
Contributions from Targa Resources Corp.	-	4.4	-	0.6	-	-	5.0
Distributions to noncontrolling interests	-	-	-	-	-	(11.6)	(11.6)
Contributions from noncontrolling interests	-	-	-	-	-	1.3	1.3
Other comprehensive loss	-	-	-	-	(37.6)	-	(37.6)
Net income	-	76.6	-	16.5	-	20.7	113.8
Distributions to unitholders	-	(93.6)	-	(15.0)	-	-	(108.6)
Balance, June 30, 2011	84.7	$ 1,221.5	1.7	$ 23.5	$ (68.2)	$ 139.7	$ 1,316.5

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2011	2010
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 113.8	$ 72.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	5.7	2.6
Compensation on equity grants	0.8	0.2
Interest expense on affiliate and allocated indebtedness	-	25.5
Depreciation and other amortization expense	87.2	85.0
Accretion of asset retirement obligations	1.8	1.6
Deferred income tax expense	1.5	0.6
Equity in earnings of unconsolidated investment, net of distributions	-	(0.8)
Risk management activities	4.0	(15.1)
Changes in operating assets and liabilities:		
Receivables and other assets	(47.0)	75.2
Inventory	(17.4)	(10.4)
Accounts payable and other liabilities	102.3	(58.6)
Net cash provided by operating activities	252.7	178.6
Cash flows from investing activities		
Outlays for property, plant and equipment	(135.7)	(45.8)
Proceeds from sales of assets	-	0.2
Business acquisition	(29.0)	-
Investment in unconsolidated affiliate	(6.0)	-
Unconsolidated affiliate distributions in excess of accumulated earnings	0.6	-
Other, net	-	1.9
Net cash used in investing activities	(170.1)	(43.7)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	611.0	635.8
Repayments of credit facility	(1,178.3)	(385.2)
Proceeds from issuance of senior notes	325.0	-
Cash paid on note exchange	(27.7)	-
Repayment of affiliated and allocated indebtedness	-	(332.8)
Proceeds from equity offerings	304.3	142.7
Distributions to unitholders	(108.6)	(77.6)
Costs incurred in connection with financing arrangements	(6.2)	-
Contributions (distributions) from (to) parent	5.0	(87.2)
Distributions under common control	-	(24.2)
Contributions from noncontrolling interests	1.3	-
Distributions to noncontrolling interests	(11.6)	(11.2)
Net cash used in financing activities	(85.8)	(139.7)
Net change in cash and cash equivalents	(3.2)	(4.8)
Cash and cash equivalents, beginning of period	76.3	90.9
Cash and cash equivalents, end of period	$ 73.1	$ 86.1

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

The year-end condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America. Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 — Organization and Operations

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange under the symbol "NGLS." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa. As of June 30, 2011, Targa and its subsidiaries own a 15.5% interest in us in the form of 1,729,715 general partner units, and 11,645,659 common units as well as all of the incentive distribution rights ("IDRs").

We acquired Targa's ownership interests in the following assets, liabilities and operations on the dates indicated:

- February 2007 – North Texas System;
- October 2007 – San Angelo ("SAOU") and Louisiana ("LOU");
- September 2009 – Downstream Business;
- April 2010 – Permian Business and Straddle Assets (See Note 4);
- August 2010 – Versado (See Note 4); and
- September 2010 – Venice Operations (See Note 4).

For periods prior to the above acquisition dates, we refer to the operations, assets and liabilities of these conveyances collectively as our "predecessors."

Allocation of costs. The employees supporting our operations are employees of Targa. Our financial statements include the direct costs of employees deployed to our operating units, as well an allocation of costs associated with our usage of Targa centralized general and administrative services and related administrative assets.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil located on the Houston Ship Channel. See Note 13 for an analysis of our operations by segment.

Note 2 — Basis of Presentation

We have prepared these unaudited consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. While we derived the year-end balance sheet data from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods.

Certain amounts in prior periods have been reclassified to conform to the current year presentation. The unaudited consolidated financial statements for the three and six months ended June 30, 2011 and 2010 include all adjustments which we believe are necessary for a fair presentation of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation.

Our financial results for the three and six months ended June 30, 2011 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2011. These unaudited consolidated financial statements and other information included in this Quarterly Report should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report for the year ended December 31, 2010.

We are required by GAAP to record the acquisitions described in Note 1 based on Targa's historical amounts, assuming that the acquisitions occurred at the date they qualified as entities under common control (October 31, 2005) following the acquisition of SAOU and LOU. We recognize the difference between our acquisition cost and the Targa basis in the net assets as an adjustment to owners' equity. We have retrospectively adjusted the financial statements, footnotes and other financial information presented for any period affected by common control accounting to reflect the results of the combined entities.

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies that we follow are set forth in Note 4 of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2010. There have been no significant changes to these policies during the six months ended June 30, 2011.

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, requires additional disclosures with regard to fair value measurements categorized within Level 3 of the fair value hierarchy. Early adoption is not permitted.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, stipulates the financial statement presentation requirements for other comprehensive income. Our financial statement presentation complies with this standards update.

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Note 4 — Acquisitions Under Common Control

On April 27, 2010, we acquired Targa's interests in its Permian Business and Straddle Assets for $420.0 million, effective April 1, 2010. We financed this acquisition substantially through borrowings under our senior secured revolving credit facility. The total consideration was used to repay outstanding affiliated indebtedness of $332.8 million, with the remaining $87.2 million of consideration reported as a parent distribution.

On August 25, 2010, we acquired Targa's 63% equity interest in Versado Gas Processors L.L.C. ("Versado"), effective August 1, 2010, for $247.2 million in the form of $244.7 million in cash and $2.5 million in partnership interests represented by 89,813 common units and 1,833 general partner units. This consideration was used to repay $247.2 million of affiliated indebtedness. Targa contributed the remaining $205.8 million of affiliate indebtedness as a capital contribution. Under the terms of the Versado acquisition purchase and sale agreement, Targa will reimburse us for future maintenance capital expenditures required pursuant to the New Mexico Environmental Department ("NMED") settlement agreement, of which our share is currently estimated to be $21.0 million, including $9.1 million that has been incurred as of June 30, 2011.

On September 28, 2010, we acquired Targa's Venice Operations, which includes Targa's 76.8% interest in Venice Energy Services Company, L.L.C. ("VESCO"), for aggregate consideration of $175.6 million, effective September 1, 2010. This consideration was used to repay $160.2 million of affiliate indebtedness, with the remaining $15.4 million of consideration reported as a parent distribution.

These acquisitions have been accounted for as acquisitions under common control, resulting in the retrospective adjustment of our prior results.

Note 5 — Property, Plant and Equipment

	June 30, 2011	December 31, 2010	Estimated useful lives (In years)
Natural gas gathering systems	$ 1,678.0	$ 1,630.9	5 to 20
Processing and fractionation facilities	1,037.6	961.9	5 to 25
Terminaling and storage facilities (1)	272.2	244.7	5 to 25
Transportation assets	277.2	275.6	10 to 25
Other property, plant and equipment	50.9	46.8	3 to 25
Land	53.2	51.2	-
Construction in progress	96.1	88.4	-
	$ 3,465.2	$ 3,299.5	

(1) Includes the March 2011 acquisition of a refined petroleum products and crude oil storage facility for which we paid $29.0 million.

Note 6 — Debt Obligations

	June 30, 2011	December 31, 2010
Senior secured revolving credit facility, variable rate, due July 2015	$ 198.0	$ 765.3
Senior unsecured notes, 8¼% fixed rate, due July 2016	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	231.3
Unamortized discounts	(3.1)	(10.3)
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	-
Unamortized discounts	(33.8)	-
	$ 1,176.5	$ 1,445.4
Letters of credit issued	$ 86.3	$ 101.3

The following table shows the range of interest rates paid and weighted average interest rate paid on our variable-rate debt obligations during the six months ended June 30, 2011:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Senior secured revolving credit facility	2.4% - 5.8%	2.9%

Compliance with Debt Covenants

As of June 30, 2011, we were in compliance with the covenants contained in our various debt agreements.

Senior Secured Credit Facility

As of June 30, 2011, availability under our senior secured credit facility was $815.7 million, after giving effect to $86.3 million in outstanding letters of credit.

6⅞% Senior Notes

On February 2, 2011, we closed a private placement of $325.0 million in aggregate principal amount of 6⅞% Senior Notes due 2021 (the "6⅞% Notes"). The net proceeds of this offering were $318.8 million after deducting expenses of the offering. We used the net proceeds from the offering to reduce borrowings under our senior secured credit facility and for general partnership purposes.

On February 4, 2011, we exchanged an additional $158.6 million principal amount of 6⅞% Notes plus payments of $28.6 million including $0.9 million of accrued interest for $158.6 million aggregate principal amount of our 11¼% Senior Notes due 2017 (the "11¼% Notes"). The holders of the exchanged Notes are subject to the provisions of the 6⅞% Notes described below. The debt covenants related to the remaining $72.7 million of face value of our 11¼% Notes were removed. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

The 6⅞% Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness, including indebtedness under our credit facility. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by certain of our subsidiaries. These notes are effectively subordinated to all secured indebtedness under our credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 6⅞% Notes accrues at the rate of 6⅞% per annum and is payable semi-annually in arrears on February 1 and August 1, commencing on August 1, 2011.

We may redeem 35% of the aggregate principal amount of the 6⅞% Notes at any time prior to February 1, 2014, with the net cash proceeds of one or more equity offerings. We must pay a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

1) at least 65% of the aggregate principal amount of the 6⅞ Notes (excluding 6⅞ Notes held by us) remains outstanding immediately after the occurrence of such redemption; and

2) the redemption occurs within 90 days of the date of the closing of such equity offering.

We may also redeem all or part of the 6⅞% Notes on or after August 1, 2016 at the redemption prices set forth below plus accrued and unpaid interest and liquidated damages, if any, on the notes redeemed, if redeemed during the twelve-month period beginning on August 1 of each year indicated below:

Year	Percentage
2016	103.44%
2017	102.29%
2018	101.15%
2019 and thereafter	100.00%

Note 7 — Partnership Equity and Distributions

On January 24, 2011, we completed a public offering of 8,000,000 common units under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.2 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011, we issued an additional 1,200,000 common units, providing net proceeds of $38.8 million. In addition, Targa contributed $6.3 million to us for 187,755 general partner units to maintain its 2% general partner interest in us.

Distributions for the six months ended June 30, 2011 and 2010 were as follows:

		Distributions (1)				
		Limited Partners	General Partner			
Date Paid	For the Three Months Ended	Common	Incentive	2%	Total	Distributions per limited partner unit
		(In millions, except per unit amounts)				
May 13, 2011	March 31, 2011	$ 47.3	$ 6.8	$ 1.1	$ 55.2	$ 0.5575
February 14, 2011	December 31, 2010	46.4	6.0	1.1	53.5	0.5475
August 13, 2010	June 30, 2010	35.9	3.5	0.8	40.2	0.5275
May 14, 2010	March 31, 2010	35.2	2.8	0.8	38.8	0.5175
February 12, 2010	December 31, 2009	35.2	2.8	0.8	38.8	0.5175

(1) On July 11, 2011, we announced a cash distribution of $0.57 per common unit on our outstanding common units for the three months ended June 30, 2011, to be paid on August 12, 2011. The distribution to be paid is $41.7 million to our third-party limited partners, and $6.6 million, $7.8 million and $1.2 million to Targa for its ownership of common units, incentive distribution rights and its 2% general partner interest in us.

Note 8 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of our commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas and NGL equity volumes through 2013 and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (floors).

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition, as well as specific NGL hedges of ethane and propane. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Additionally, the NGL hedges are based on published index prices for delivery at Mont Belvieu and the natural gas hedges are based on published index prices for delivery at Permian Basin, Mid-Continent and WAHA, which closely approximate our actual NGL and natural gas delivery points.

We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying West Texas condensate equity volumes.

Hedge ineffectiveness has been immaterial for all periods.

At June 30, 2011, the notional volumes of our commodity hedges were:

Commodity	Instrument	Unit	2011	2012	2013	2014
Natural Gas	Swaps	MMBtu/d	38,470	31,790	17,089	-
NGL	Swaps	Bbl/d	10,118	9,361	4,150	-
NGL	Floors	Bbl/d	253	294	-	-
Condensate	Swaps	Bbl/d	1,730	1,660	1,795	700

Interest Rate Swaps

As of June 30, 2011, we had $198.0 million outstanding under our credit facility, with interest accruing at a base rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates, we have entered into interest rate swaps and interest rate basis swaps as shown below:

Period	Fixed Rate	Notional Amount	Fair Value
Remainder of 2011	3.52%	$ 300	$ (5.0)
2012	3.40%	300	(7.1)
2013	3.39%	300	(6.3)
1/1/2014 - 4/24/2014	3.39%	300	(1.9)
			$ (20.3)

Derivative Instruments Not Designated as Hedging Instruments

Our fixed interest rate swaps, which total $300.0 million in notional principal, and interest rate basis swaps, which total $200.0 million in notional principal, had been designated as cash flow hedges of variable rate interest payments on borrowings under our credit facility until February 11, 2011, when we de-designated $125.0 million notional principal of fixed interest rate swaps and $25.0 million notional principal of interest rate basis swaps. We de-designated the swaps as our borrowings under our credit facility reduced below $300.0 million, which is the total notional amount of our fixed interest rate swaps. The de-designated swaps receive mark-to-market treatment, with changes in fair value, cash and accrued settlements recorded to other income (expense).

We frequently enter into derivative instruments to manage location basis differentials. Based on the current application of the basis derivatives, we do not account for these derivatives as hedges and we record changes in fair value and cash settlements to revenues.

The following schedules reflect the fair values of derivative instruments in our financial statements:

	Derivative Assets			Derivative Liabilities		
	Balance Sheet Location	Fair Value as of June 30, 2011	Fair Value as of December 31, 2010	Balance Sheet Location	Fair Value as of June 30, 2011	Fair Value as of December 31, 2010
Designated as hedging instruments						
Commodity contracts	Current assets	$ 22.1	$ 24.8	Current liabilities	$ 48.4	$ 25.5
	Long-term assets	12.8	18.9	Long-term liabilities	32.0	20.5
Interest rate contracts	Current assets	-	-	Current liabilities	4.8	7.8
	Long-term assets	-	-	Long-term liabilities	7.5	12.3
Total designated as hedging instruments		$ 34.9	$ 43.7		$ 92.7	$ 66.1
Not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.4	$ 0.4	Current liabilities	$ 0.7	$ 0.9
	Long-term assets	0.4	-	Long-term liabilities	-	-
Interest rate contracts	Current assets	-	-	Current liabilities	3.0	-
	Long-term assets	-	-	Long-term liabilities	5.0	-
Total not designated as hedging instruments		$ 0.8	$ 0.4		$ 8.7	$ 0.9
Total derivatives		$ 35.7	$ 44.1		$ 101.4	$ 67.0

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets.

The following tables reflect amounts recorded in accumulated other comprehensive income ("OCI") and amounts reclassified from OCI to revenue and expense:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Interest rate contracts	$ (2.2)	$ (10.1)	$ (1.9)	$ (16.8)
Commodity contracts	4.4	26.6	(56.9)	60.2
	$ 2.2	$ 16.5	$ (58.8)	$ 43.4

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2011	2010	2011	2010
Interest expense, net	$ (2.2)	$ (3.4)	$ (4.6)	$ (5.0)
Revenues	(11.9)	3.2	(16.5)	0.2
	$ (14.1)	$ (0.2)	$ (21.1)	$ (4.8)

Our earnings are also affected by the use of the mark-to-market method of accounting for derivative financial instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying price indices.

During the three and six months ended June 30, 2011 and 2010, we recorded the following mark-to-market gains (losses):

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2011	2010	2011	2010
Commodity contracts	Other income (expense)	$ -	$ 2.4	$ -	$ 27.8
Interest rate swaps	Other income (expense)	(3.2)	-	(3.2)	-
		$ (3.2)	$ 2.4	$ (3.2)	$ 27.8

The following table shows the unrealized gains (losses) included in OCI:

	June 30, 2011	December 31, 2010
Unrealized net losses on commodity hedges	$ (51.0)	$ (10.5)
Unrealized net losses on interest rate hedges	$ (17.4)	$ (20.1)

As of June 30, 2011, deferred net losses of $30.7 million on commodity hedges and $8.1 million on interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

In July 2008, we and Targa paid $77.8 million and $9.6 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. We and Targa also entered into new natural gas and NGL commodity swaps at then current market prices that match the production volumes of the terminated swaps. Prior to the terminations, these swaps were designated as cash flow hedges. During the three and six months ended June 30, 2011, an immaterial amount of deferred loss related to the terminated swaps was reclassified from OCI as a non-cash reduction to revenue. During the three and six months ending June 30, 2010, $7.1 million and $14.0 million of deferred losses related to the terminated swaps were reclassified from OCI as a non-cash reduction to revenue.

See Note 3 and Note 9 for additional disclosures related to derivative instruments and hedging activities.

Note 9 — Fair Value Measurements

We categorize the inputs to the fair value of our financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that are either directly or indirectly observable; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative instruments consist of financially settled commodity and interest rate swap and option contracts and fixed price commodity contracts with certain counterparties. We determine the value of our derivative contracts using a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

Contracts classified as Level 3 are valued using price inputs available from public markets to the extent that the markets are liquid for the relevant settlement periods.

The following tables present the fair value of our financial assets and liabilities according to the fair value hierarchy. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels:

	June 30, 2011			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 35.7	$ -	$ 35.7	$ -
Total assets	$ 35.7	$ -	$ 35.7	$ -
Liabilities from commodity derivative contracts	$ 81.1	$ -	$ 80.2	$ 0.9
Liabilities from interest rate derivatives	20.3	-	20.3	-
Total liabilities	$ 101.4	$ -	$ 100.5	$ 0.9

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 44.1	$ -	$ 43.9	$ 0.2
Total assets	$ 44.1	$ -	$ 43.9	$ 0.2
Liabilities from commodity derivative contracts	$ 46.9	$ -	$ 35.1	$ 11.8
Liabilities from interest rate derivatives	20.1	-	20.1	-
Total liabilities	$ 67.0	$ -	$ 55.2	$ 11.8

The following table sets forth a reconciliation of the changes in the fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts
Balance, December 31, 2010	$ (11.6)
Unrealized losses included in OCI	(0.4)
Settlements included in Net Income	3.7
Transfers out of Level 3	7.4
Balance, June 30, 2011	$ (0.9)

We transferred $7.4 million in derivative liabilities from Level 3 to Level 2 in the second quarter. The transfer is attributable to increased transparency and liquidity in the NGL markets, specifically with regard to 2013 prices.

We designated all Level 3 derivative instruments as cash flow hedges, and, as such, all changes in their fair value are reflected in OCI. Therefore, there are no unrealized gains or losses reflected in revenues or other income (expense) with respect to Level 3 derivative instruments.

Note 10 — Fair Value of Financial Instruments

The estimated fair values of assets and liabilities classified as financial instruments have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short term maturities of these instruments. Derivative financial instruments included in our financial statements are stated at fair value.

The carrying value of our senior secured revolving credit facility approximates its fair value, as its interest rate is based on prevailing market rates. The fair value of the senior unsecured notes is based on quoted market prices based on trades of such debt as of the dates indicated in the following table:

	June 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior unsecured notes, 8¼% fixed rate	$ 209.1	$ 223.9	$ 209.1	$ 219.4
Senior unsecured notes, 11¼% fixed rate	69.6	84.8	221.0	253.2
Senior unsecured notes, 7⅞% fixed rate	250.0	261.7	250.0	259.7
Senior unsecured notes, 6⅞% fixed rate	449.8	473.9	N/A	N/A

Note 11 — Commitments and Contingencies

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Environmental reserves do not reflect management's assessment of any insurance coverage that may be applicable to the matters at issue. Management has assessed each of the matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success.

Our environmental liability at June 30, 2011 and December 31, 2010 was $1.4 million and $1.6 million. Our June 30, 2011 liability consisted of $1.4 million for ground water assessment and remediation.

In May 2007, the NMED alleged air emissions violations at the Eunice, Monument and Saunders gas processing plants, which are operated by us and owned by Versado, were identified in the course of an inspection of the Eunice plant conducted by the NMED in August 2005.

In January 2010, Versado settled the alleged violations with NMED for a penalty of approximately $1.5 million. As part of the settlement, Versado agreed to install two acid gas injection wells, additional emission control equipment and monitoring equipment. We estimate the total cost to complete these projects to be approximately $33.4 million, of which our portion of the cost is projected to be $21.0 million. As of June 30, 2011, $14.5 million has been paid by Versado, of which our share was $9.1 million.

Under the terms of the Versado acquisition purchase and sale agreement between Targa and us, Targa is obligated to reimburse us for maintenance capital expenditures required pursuant to the NMED settlement agreement.

Legal Proceedings

We are a party to various legal proceedings and/or regulatory proceedings and certain claims, suits and complaints arising in the ordinary course of business that have been filed or are pending against us. We believe all such matters are without merit or involve amounts which, if resolved unfavorably, would not have a material effect on our financial position, results of operations, or cash flows.

Note 12 — Supplemental Cash Flow Information

Supplemental cash flow information was as follows for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Interest paid	$ 16.7	$ 5.0	$ 46.5	$ 31.8
Taxes paid	1.9	1.5	2.2	1.6
Non-cash adjustment to line-fill	-	0.5	(2.1)	0.5

Note 13 — Segment Information

We report our operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting natural gas liquids and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert raw natural gas liquids into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, crude and refined products. It also includes certain natural gas supply and marketing activities in support of our other businesses.

The Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling crude oil and refined petroleum products. These assets are generally connected to and supplied in part by, our Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the March 2011 acquisition of a refined petroleum products and crude oil storage and terminaling facility located on the Houston Ship Channel.

The Marketing and Distribution segment covers all activities required to distribute and market raw and finished natural gas liquids and all natural gas marketing activities. It includes (1) marketing our own natural gas liquids production and purchasing natural gas liquids products in selected United States markets; (2) providing liquefied petroleum gas balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users; and (4) marketing natural gas available to us from our Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

Other contains the results of our commodity hedging activities. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

Our reportable segment information is shown in the following tables:

Three Months Ended June 30, 2011	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues	$ 58.2	$ 94.3	$ 33.1	$ 1,552.9	$ (13.2)	$ 0.1	$ 1,725.4
Intersegment revenues	367.2	244.9	24.7	171.9	-	(808.7)	-
Revenues	$ 425.4	$ 339.2	$ 57.8	$ 1,724.8	$ (13.2)	$ (808.6)	$ 1,725.4
Operating margin	$ 80.2	$ 45.7	$ 33.4	$ 30.5	$ (13.2)	$ -	$ 176.6
Other financial information:							
Total assets	$ 1,650.4	$ 430.5	$ 546.9	$ 573.1	$ 35.7	$ 91.8	$ 3,328.4
Capital expenditures	$ 40.0	$ 4.2	$ 42.5	$ 0.8	$ -	$ 0.5	$ 88.0

Three Months Ended June 30, 2010	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues	$ 57.5	$ 103.2	$ 19.9	$ 1,054.4	$ 2.7	$ (0.1)	$ 1,237.6
Intersegment revenues	247.8	199.0	20.9	128.1	-	(595.8)	-
Revenues	$ 305.3	$ 302.2	$ 40.8	$ 1,182.5	$ 2.7	$ (595.9)	$ 1,237.6
Operating margin	$ 59.4	$ 23.7	$ 18.0	$ 14.1	$ 2.7	$ (0.1)	$ 117.8
Other financial information:							
Total assets	$ 1,653.2	$ 462.5	$ 422.1	$ 392.9	$ 70.0	$ 64.1	$ 3,064.8
Capital expenditures	$ 14.8	$ 1.4	$ 10.6	$ 0.7	$ -	$ -	$ 27.5

Six Months Ended June 30, 2011	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues	$ 110.2	$ 178.3	$ 56.4	$ 3,012.6	$ (17.6)	$ -	$ 3,339.9
Intersegment revenues	666.9	462.3	43.8	284.2	-	(1,457.2)	-
Revenues	$ 777.1	$ 640.6	$ 100.2	$ 3,296.8	$ (17.6)	$ (1,457.2)	$ 3,339.9
Operating margin	$ 141.3	$ 82.0	$ 55.7	$ 63.1	$ (17.6)	$ -	$ 324.5
Other financial information:							
Total assets	$ 1,650.4	$ 430.5	$ 546.9	$ 573.1	$ 35.7	$ 91.8	$ 3,328.4
Capital expenditures	$ 71.8	$ 5.6	$ 87.6	$ 0.9	$ -	$ 0.6	$ 166.5

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	Six Months Ended June 30, 2010						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues	$ 112.5	$ 236.7	$ 36.5	$ 2,335.9	$ (0.3)	$ 0.1	$ 2,721.4
Intersegment revenues	539.9	404.0	42.0	266.7	-	(1,252.6)	-
Revenues	$ 652.4	$ 640.7	$ 78.5	$ 2,602.6	$ (0.3)	$ (1,252.5)	$ 2,721.4
Operating margin	$ 127.5	$ 51.2	$ 29.3	$ 33.8	$ (0.3)	$ -	$ 241.5
Other financial information:							
Total assets	$ 1,653.2	$ 462.5	$ 422.1	$ 392.9	$ 70.0	$ 64.1	$ 3,064.8
Capital expenditures	$ 27.4	$ 4.2	$ 13.7	$ 0.6	$ -	$ -	$ 45.9

The following table shows our revenues by product and service for each period presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Natural gas sales	$ 294.1	$ 258.5	$ 544.0	$ 571.3
NGL sales	1,345.6	910.1	2,648.4	2,022.3
Condensate sales	33.1	26.0	54.6	51.3
Fractionating and treating fees	23.3	15.0	34.4	28.3
Storage and terminaling fees	13.3	9.3	27.2	18.8
Transportation fees	11.5	8.0	22.2	15.4
Gas processing fees	7.7	8.0	14.8	15.2
Derivative activities	(13.0)	2.9	(18.2)	(0.1)
Other	9.8	(0.2)	12.5	(1.1)
	$ 1,725.4	$ 1,237.6	$ 3,339.9	$ 2,721.4

The following table is a reconciliation of operating margin to net income for each period presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Reconciliation of operating margin to net income:				
Operating margin	$ 176.6	$ 117.8	$ 324.5	$ 241.5
Depreciation and amortization expense	(44.5)	(43.0)	(87.2)	(85.0)
General and administrative expense	(33.2)	(28.2)	(64.9)	(53.2)
Interest expense, net	(27.2)	(27.6)	(54.6)	(58.6)
Income tax expense	(1.9)	(0.9)	(3.7)	(2.4)
Other, net	(1.8)	4.8	(0.3)	30.5
Net income	$ 68.0	$ 22.9	$ 113.8	$ 72.8

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2010, as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units are listed on the New York Stock Exchange under the symbol "NGLS." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC (the "General Partner") is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa.

We acquired Targa's ownership interests in the following assets, liabilities and operations on the dates indicated (collectively, the "dropdown transactions"):

- February 2007 – North Texas System;
- October 2007 – San Angelo ("SAOU") and Louisiana ("LOU");
- September 2009 – Downstream Business;
- April 2010 – Permian Business and Straddle Assets;
- August 2010 – Versado; and
- September 2010 – Venice Operations.

For periods prior to the above acquisition dates, we refer to the operations, assets and liabilities of these acquisitions as our "predecessors."

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil.

We report our operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

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The Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling crude oil and refined petroleum products. These assets are generally connected to and supplied in part by, our Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the recent acquisition of a refined petroleum products and crude oil storage and terminaling facility located on the Houston Ship Channel.

The Marketing and Distribution segment covers all activities required to distribute and market raw and finished natural gas liquids and all natural gas marketing activities. It includes (1) marketing our own natural gas liquids production and purchasing natural gas liquids products in selected United States markets; (2) providing liquefied petroleum gas balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users; and (4) marketing natural gas available to us from our Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

Other contains the results of our commodity hedging activities.

Recent Developments

On January 24, 2011, we completed a public offering of 8,000,000 common units representing limited partner interests in us (“common units”) under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.2 million. Pursuant to the exercise of the underwriters’ overallotment option, on February 3, 2011 we issued an additional 1,200,000 common units, providing net proceeds of $38.8 million. In addition, our general partner contributed $6.3 million to us for 187,755 general partner units to maintain its 2% general partner interest in us. We used the net proceeds from the offering to reduce borrowings under our senior secured credit facility.

On February 2, 2011, we closed a private placement of $325.0 million in aggregate principal amount of 6⅞% Senior Notes due 2021 (the “6⅞% Notes”). The net proceeds of this offering were $318.8 million after deducting expenses of the offering. We used the net proceeds from the offering to reduce borrowings under our senior secured credit facility.

On February 4, 2011, we exchanged an additional $158.6 million principal amount of our 6⅞% Notes plus payments of $28.6 million, including $0.9 million of accrued interest, for $158.6 million aggregate principal amount of our 11¼% Senior Notes due 2017 (the “11¼% Notes”). The debt covenants related to the remaining $72.7 million of face value of our 11¼% Notes were removed. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

On March 15, 2011, we broadened our Logistics Assets segment portfolio with the acquisition of a refined petroleum products and crude oil storage and terminaling facility (the "Terminal") in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel for $29.0 million. The Terminal can handle multiple grades of blend stocks, products and crude and has potential for on-site expansion, as well as integration with our other logistics operations. The transaction was paid entirely with cash funded through borrowings under our senior secured revolving credit facility.

On May 9, 2011, we announced a 100,000 barrel per day expansion of our majority owned Cedar Bayou Fractionator (“CBF”) at Mont Belvieu, Texas. Anchoring this expansion is a long-term, firm-capacity fractionation agreement with DCP Midstream LLC and our internal needs for capacity. The 100,000 barrel per day expansion will be fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park, Texas on the Houston Ship Channel. Construction of the expansion will proceed without disruption to existing operations. We estimate that the total capital expenditures for the CBF expansion and our related infrastructure enhancements at Mont Belvieu should approximate $360.0 million and will be completed in the first quarter of 2013.

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, requires additional disclosures with regard to fair value measurements categorized within Level 3 of the fair value hierarchy. Early adoption is not permitted.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, stipulates the financial statement presentation requirements for other comprehensive income. Our financial statement presentation complies with this standards update.

How We Evaluate Our Operations

Our profitability is a function of the difference between the revenues we receive from our operations, including revenues from the natural gas, NGLs and condensate we sell, and the costs associated with conducting our operations, including the costs of wellhead natural gas and mixed NGLs that we purchase as well as operating and general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Our contract portfolio, the prevailing pricing environment for natural gas and NGLs and the volumes of natural gas and NGL throughput on our systems are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for our products and services and changes in our customer mix.

Our management uses a variety of financial measures and operational measurements to analyze our performance. These include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses and (3) the following non-GAAP measures — gross margin, operating margin, adjusted EBITDA and distributable cash flow.

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to our Downstream Business' fractionation facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party gathering or fractionation facilities.

In addition, we seek to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes of natural gas received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. We also monitor the volumes of NGLs received, stored, fractionated and delivered across our logistics assets. This information is tracked through our processing plants and Downstream Business' facilities to determine customer settlements for sales and volume related fees for service and helps us increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plant to monitor the fuel consumption and recoveries of the facilities. Similar tracking is performed for our logistics assets. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis.

Operating Expenses. Operating expenses are costs associated with the operation of a specific asset. Labor, contract services, repair and maintenance, utilities and ad valorem taxes comprise the most significant portion of our operating expenses. These expenses generally remain relatively stable and independent of the volumes through our systems but fluctuate depending on the scope of the activities performed during a specific period.

Gross Margin. Gross margin is defined as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and hedging program. We define Natural Gas Gathering and Processing gross margin as total operating revenues from the sales of natural gas and NGLs plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees and NGL sales, less cost of sales, which consists primarily of NGL purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin. Operating margin is an important performance measure of the core profitability of our operations. We define operating margin as gross margin less operating expenses. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges.

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income, and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definition of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Management reviews business segment gross margin and operating margin monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures by us and by external users of our financial statements, including investors and commercial banks to assess:

· the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

· our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and

· the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Adjusted EBITDA. We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and non-cash risk management activities related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others.

The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income. Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities or GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Distributable Cash Flow. We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for losses (gains) on mark-to-market derivative contracts and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). The impact of noncontrolling interests is included in this measure.

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

The GAAP measure most directly comparable to distributable cash flow is net income attributable to Targa Resources Partners LP. Distributable cash flow should not be considered as an alternative to GAAP net income attributable to Targa Resources Partners LP. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into its decision making processes.

Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to their most directly comparable GAAP measures for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Reconciliation of gross margin and operating margin to net income (loss):				
Gross margin	$ 248.2	$ 179.8	$ 462.1	$ 365.7
Operating expenses	(71.6)	(62.0)	(137.6)	(124.2)
Operating margin	176.6	117.8	324.5	241.5
Depreciation and amortization expenses	(44.5)	(43.0)	(87.2)	(85.0)
General and administrative expenses	(33.2)	(28.2)	(64.9)	(53.2)
Interest expense, net	(27.2)	(27.6)	(54.6)	(58.6)
Income tax expense	(1.9)	(0.9)	(3.7)	(2.4)
Other, net (1)	(1.8)	4.8	(0.3)	30.5
Net income	$ 68.0	$ 22.9	$ 113.8	$ 72.8

(1) Includes gain on mark-to-market derivatives, equity in earnings of unconsolidated investment, insurance claims, and other income (expense).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 154.1	$ 58.2	$ 252.7	$ 178.6
Net income attributable to noncontrolling interests	(12.8)	(6.2)	(20.7)	(13.5)
Interest expense, net (1)	23.3	16.3	48.9	30.5
Current income tax expense	0.8	1.0	2.2	1.8
Other (2)	(6.1)	2.5	(8.0)	0.2
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	135.7	22.7	64.4	(64.8)
Accounts payable and other liabilities	(165.2)	(0.6)	(102.3)	58.6
Adjusted EBITDA	$ 129.8	$ 93.9	$ 237.2	$ 191.4

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of: $3.8 million and $5.7 million for the three and six months ended June 30, 2011; and $1.4 million and $2.6 million for the three and six months ended June 30, 2010. Excludes affiliate and allocated interest expense.
(2) Includes equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation and gain (loss) on sale of assets.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 55.2	$ 16.7	$ 93.1	$ 59.3
Add:				
Interest expense, net (1)	27.2	27.6	54.6	58.6
Income tax expense	1.9	0.9	3.7	2.4
Depreciation and amortization expenses	44.5	43.0	87.2	85.0
Risk management activities	3.8	8.2	4.0	(9.0)
Noncontrolling interests adjustment	(2.8)	(2.5)	(5.4)	(4.9)
Adjusted EBITDA	$ 129.8	$ 93.9	$ 237.2	$ 191.4

(1) Includes affiliate and allocated interest expense.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:				
Net income attributable to Targa Resources Partners LP	$ 55.2	$ 16.7	$ 93.1	$ 59.3
Affiliate and allocated interest expense	-	9.9	-	25.5
Depreciation and amortization expenses	44.5	43.0	87.2	85.0
Deferred income tax expense	1.1	(0.1)	1.5	0.6
Amortization in interest expense	3.8	1.4	5.7	2.6
Risk management activities	3.8	8.2	4.0	(9.0)
Maintenance capital expenditures	(21.6)	(10.2)	(32.6)	(17.1)
Other (1)	3.2	(0.9)	5.2	(2.5)
Distributable cash flow	$ 90.0	$ 68.0	$ 164.1	$ 144.4

(1) Includes reimbursements of certain environmental maintenance capital expenditures by Targa and the non-controlling interest portion of maintenance capital expenditures and depreciation expense.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are set forth in Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report. There have been no material changes to these policies and estimates during the six months ended June 30, 2011.

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Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2011 and 2010 (in millions, except operating and price amounts):

	Three Months Ended June 30,		2011 vs. 2010		Six Months Ended June 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
Revenues	$ 1,725.4	$ 1,237.6	$ 487.8	39%	$ 3,339.9	$ 2,721.4	$ 618.5	23%
Product purchases	1,477.2	1,057.8	419.4	40%	2,877.8	2,355.7	522.1	22%
Gross margin (1)	248.2	179.8	68.4	38%	462.1	365.7	96.4	26%
Operating expenses	71.6	62.0	9.6	15%	137.6	124.2	13.4	11%
Operating margin (2)	176.6	117.8	58.8	50%	324.5	241.5	83.0	34%
Depreciation and amortization expenses	44.5	43.0	1.5	3%	87.2	85.0	2.2	3%
General and administrative expenses	33.2	28.2	5.0	18%	64.9	53.2	11.7	22%
Income from operations	98.9	46.6	52.3	112%	172.4	103.3	69.1	67%
Interest expense, net	(27.2)	(27.6)	0.4	1%	(54.6)	(58.6)	4.0	7%
Equity in earnings of unconsolidated investments	1.3	2.4	(1.1)	-46%	3.0	2.7	0.3	11%
Gain (loss) on mark-to-market derivative instruments	(3.2)	2.4	(5.6)	(233%)	(3.2)	27.8	(31.0)	(112%)
Other	0.1	-	0.1	-	(0.1)	-	(0.1)	-
Income tax expense	(1.9)	(0.9)	(1.0)	(111%)	(3.7)	(2.4)	(1.3)	(54%)
Net income	68.0	22.9	45.1	197%	113.8	72.8	41.0	56%
Less: Net income attributable to noncontrolling interests	12.8	6.2	6.6	106%	20.7	13.5	7.2	53%
Net income (loss) attributable to Targa Resources Partners LP	$ 55.2	$ 16.7	$ 38.5	231%	$ 93.1	$ 59.3	$ 33.8	57%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 129.8	$ 93.9	$ 35.9	38%	$ 237.2	$ 191.4	$ 45.8	24%
Distributable cash flow (4)	90.0	68.0	22.0	32%	164.1	144.4	19.7	14%
Operating data:								
Plant natural gas inlet, MMcf/d (5) (6)	2,203.6	2,342.8	(139.2)	(6%)	2,186.2	2,337.3	(151.1)	(6%)
Gross NGL production, MBbl/d	126.1	122.0	4.1	3%	122.6	120.3	2.3	2%
Natural gas sales, BBtu/d (6)	755.0	698.7	56.3	8%	718.8	681.7	37.1	5%
NGL sales, MBbl/d	261.0	240.9	20.1	8%	268.3	246.9	21.4	9%
Condensate sales, MBbl/d	3.7	3.8	(0.1)	(3%)	3.1	3.7	(0.6)	(16%)

(1) Gross margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations” and “Non-GAAP Financial Measures.”
(2) Operating margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations” and “Non-GAAP Financial Measures.”
(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and non-cash risk management activities related to derivative instruments. This is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations” and “Non-GAAP Financial Measures.”
(4) Distributable cash flow is net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for losses (gains) on mark-to-market derivative contracts and debt repurchases, less maintenance capital expenditures (net of any reimbursements of project costs). This is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations” and “Non-GAAP Financial Measures.”
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

Consolidated revenues (including the impacts of hedging) increased due to higher net impact of realized commodity prices ($365.1 million), higher NGL and natural gas sales volumes ($97.0 million) and higher fee-based and other revenues ($26.6 million) including a contract settlement ($7.5 million) related to a restructured multi-year propane exchange agreement which may result in the receipt of future payments over the remaining term of the contract, partially offset by lower condensate sales volumes ($0.9 million).

Consolidated operating margin increased $58.8 million, reflecting higher gross margin partially offset by increased operating expenses. The increase in consolidated gross margin reflects higher revenues ($487.8 million) partially offset by increases in product purchase costs ($419.4 million). The increase in consolidated operating expenses of $9.6 million primarily reflects increased compensation and benefits, maintenance and fuel, utilities and catalyst costs. See "Results of Operations—By Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses of $1.5 million is primarily driven by the impact of depreciation expense related to new assets placed in service since the second quarter of 2010.

General and administrative expenses increased $5.0 million reflecting higher allocations of increased compensation and benefits.

Interest expense decreased by $0.4 million. This is attributable to an increase of interest expense on third party debt of $9.5 million offset by a decrease of $9.9 million on affiliate and allocated interest expense. There was no interest expense related to affiliate or allocated debt in 2011 as these balances were retired as part of the Permian, VESCO and Versado drop-down transactions in 2010.

See "—Liquidity and Capital Resources" for information regarding our outstanding debt obligations.

Mark-to-market gains decreased $5.6 million, moving from a gain of $2.4 million to a loss of $3.2 million. The gain in 2010 is attributable to the accounting treatment of commodity derivatives related to the Permian and Versado acquisitions during 2010. Under common control accounting, these derivatives did not qualify for hedge accounting treatment for predecessor periods prior to our acquisition of the assets. Therefore, changes in fair value for these instruments were recorded in earnings. These derivative instruments were designated as hedges as of the date of these acquisitions, and therefore changes in value subsequent to those dates are recorded in other comprehensive income until the underlying transactions settle. We did not have mark-to-market gains on these derivatives during 2011, and will not have future mark-to-market gains or losses unless the hedges are de-designated. The loss in 2011 is attributable to interest rate swaps that did not qualify for hedge accounting as of February 11, 2011. See "Item 3. Quantitative and Qualitative Disclosures About Market Risk" in this Quarterly Report for more information regarding de-designated interest rate swaps.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Consolidated revenues (including the impacts of hedging) increased due to the net impact of higher realized commodity prices on NGL's and condensate ($444.4 million), higher NGL and natural gas sales volumes ($206.2 million) and higher fee-based and other revenues ($36.8 million) including a contract settlement ($7.5 million) related to a restructured multi-year propane exchange agreement which may result in the receipt of future payments over the remaining term of the contract, partially offset by lower realized pricing on natural gas ($60.9 million) and lower condensate sales volumes ($8.0 million).

Consolidated operating margin increased $83.0 million, reflecting higher gross margin partially offset by increased operating expenses. The increase in consolidated gross margin reflects higher revenues ($618.5 million) partially offset by increases in product purchase costs ($522.1 million). The increase in consolidated operating expenses of $13.4 million primarily reflects increased compensation and benefits, maintenance and fuel, utilities and catalyst costs. See "Results of Operations—By Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses of $2.2 million is primarily driven by the impact of depreciation expense related to new assets placed in service since the second quarter of 2010.

General and administrative expenses increased $11.7 million reflecting higher allocations of increased compensation and benefits.

Interest expense decreased by $4.0 million attributable to $21.5 million increase in interest expense on third party debt offset by $25.5 million decrease on affiliate and allocated interest expense. There was no interest expense related to affiliate or allocated debt in 2011 as these balances were retired as part of the Versado, VESCO and Permian drop-down transactions in 2010.

See "—Liquidity and Capital Resources" for information regarding our outstanding debt obligations.

Mark-to-market gains decreased $31.0 million, moving from a gain of $27.8 million to a loss of $3.2 million. The gain in 2010 is attributable to the accounting treatment of commodity derivatives related to the Permian and Versado acquisitions during 2010. Under common control accounting, these derivatives did not qualify for hedge accounting treatment for predecessor periods prior to our acquisition of the assets. Therefore, changes in fair value for these instruments were recorded in earnings. These derivative instruments were designated as hedges as of the date of these acquisitions, and therefore changes in value subsequent to those dates are recorded in other comprehensive income until the underlying transactions settle. We did not have mark-to-market gains on these derivatives during 2011, and will not have future mark-to-market gains or losses unless the hedges are de-designated. The loss in 2011 is attributable to interest rate swaps that did not qualify for hedge accounting as of February 11, 2011. See "Item 3. Quantitative and Qualitative Disclosures About Market Risk" in this Quarterly Report for more information regarding de-designated interest rate swaps.

Results of Operations—By Segment

Our operating margin by reportable segment is:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
				(In millions)			
Three Months Ended June 30, 2011	$ 80.2	$ 45.7	$ 33.4	$ 30.5	$ (13.2)	$ -	$ 176.6
Three Months Ended June 30, 2010	59.4	23.7	18.0	14.1	2.7	(0.1)	117.8
Six Months Ended June 30, 2011	$ 141.3	$ 82.0	$ 55.7	$ 63.1	$ (17.6)	$ -	$ 324.5
Six Months Ended June 30, 2010	127.5	51.2	29.3	33.8	(0.3)	-	241.5

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30,		2011 vs. 2010		Six Months Ended June 30,		2011 vs. 2010	
	2011	**2010**	**$ Change**	**% Change**	**2011**	**2010**	**$ Change**	**% Change**
				($ in millions)				
Gross margin	$ 109.1	$ 83.1	$ 26.0	31%	$ 197.0	$ 173.1	$ 23.9	14%
Operating expenses	28.9	23.7	5.2	22%	55.7	45.6	10.1	22%
Operating margin	$ 80.2	$ 59.4	$ 20.8	35%	$ 141.3	$ 127.5	$ 13.8	11%
Operating statistics:								
Plant natural gas inlet, MMcf/d (1),(2)	611.7	585.7	26.0	4%	592.4	581.1	11.3	2%
Gross NGL production, MBbl/d	74.6	70.8	3.8	5%	72.0	70.0	2.0	3%
Natural gas sales, BBtu/d (2), (3)	284.4	263.6	20.8	8%	273.8	258.6	15.2	6%
NGL sales, MBbl/d (3)	59.9	56.7	3.2	6%	58.2	55.9	2.3	4%
Condensate sales, MBbl/d (3)	3.4	3.4	-	-	2.8	2.9	(0.1)	(3%)
Average realized prices (4):								
Natural gas, $/MMBtu	4.05	3.76	0.29	8%	3.94	4.45	(0.51)	(11%)
NGL, $/gal	1.25	0.87	0.38	44%	1.18	0.93	0.25	27%
Condensate, $/Bbl	98.13	73.81	24.32	33%	95.27	74.76	20.51	27%

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(3) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(4) Average realized prices exclude the impact of hedging activities.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

The $26.0 million increase in gross margin for 2011 was primarily due to higher commodity sales prices ($101.9 million), higher natural gas and NGL sales volumes ($18.0 million) and higher fee based and other revenues ($0.3 million), partially offset by higher product purchases ($94.1 million). The increase in plant inlet volumes was largely attributable to new well connects throughout our systems, particularly North Texas and SAOU, partially offset by production declines at our Versado system.

The $5.2 million increase in operating expenses was primarily due to higher fuel, utilities and catalysts expenses ($1.2 million), higher system maintenance expenses ($1.1 million), higher compensation and benefit costs ($2.0 million) and higher contract and professional service expenses ($1.0 million).

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

The $23.9 million increase in gross margin for 2011 was primarily due to higher NGL and condensate sales prices ($122.2 million), higher natural gas and NGL volumes ($28.3 million) and higher fee based and other revenues ($1.3 million), partially offset by higher product purchases ($100.8 million), lower natural gas sales prices ($25.4 million), and lower condensate sales volumes ($1.6 million). The increase in plant inlet volumes was largely attributable to new well connects throughout our systems, particularly North Texas and SAOU, partially offset by the impact of severe cold weather in the first quarter of 2011 and operational outages combined with production declines at our Versado system.

The $10.1 million increase in operating expenses was primarily due to higher fuel, utilities and catalysts expenses ($2.8 million), higher system maintenance expenses ($2.5 million) driven by severe cold weather and operational outages in the first quarter of 2011, higher compensation and benefit costs ($2.8 million) and higher contract and professional service expenses ($2.0 million).

Coastal Gathering and Processing

	Three Months Ended June 30,		2011 vs. 2010		Six Months Ended June 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
	($ in millions)							
Gross margin	$ 57.1	$ 34.6	$ 22.5	65%	$ 103.6	$ 72.0	$ 31.6	44%
Operating expenses	11.4	10.9	0.5	5%	21.6	20.8	0.8	4%
Operating margin	$ 45.7	$ 23.7	$ 22.0	93%	$ 82.0	$ 51.2	$ 30.8	60%
Operating statistics:								
Plant natural gas inlet, MMcf/d (1),(2),(3)	1,591.9	1,757.2	(165.3)	(9%)	1,593.9	1,756.1	(162.2)	(9%)
Gross NGL production, MBbl/d	51.5	51.2	0.3	1%	50.6	50.3	0.3	1%
Natural gas sales, Bbtu/d (3), (4)	270.7	310.3	(39.6)	(13%)	262.5	312.1	(49.6)	(16%)
NGL sales, MBbl/d (4)	43.8	46.4	(2.6)	(6%)	43.7	44.9	(1.2)	(3%)
Condensate sales, MBbl/d (4)	0.3	0.4	(0.1)	(25%)	0.3	0.8	(0.5)	(63%)
Average realized prices (5):								
Natural gas, $/MMBtu	4.35	4.25	0.10	2%	4.25	4.76	(0.51)	(11%)
NGL, $/gal	1.34	0.98	0.36	36%	1.27	1.03	0.24	23%
Condensate, $/Bbl	109.05	84.73	24.32	29%	100.51	79.33	21.18	27%

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) The majority of our Coastal Straddle plant volumes are gathered on third-party offshore pipeline systems and delivered to the plant inlets.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(5) Average realized prices exclude the impact of hedging activities.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

The $22.5 million increase in gross margin for 2011 is primarily due to an increase in commodity sales prices ($62.5 million) and an increase fee based and other revenues ($0.7 million), partially offset by an increase in product purchases ($14.5 million) and a decrease in commodity sales volumes ($26.2 million). The decrease in plant inlet volumes was largely attributable to a decline in traditional wellhead and leaner offshore supply volumes. The impact of the decrease in plant inlet was offset by incrementally adding volumes at facilities with higher recovery levels. Natural gas sales volumes decreased due to lower demand from our industrial customers and lower sales to other reportable segments for resale.

Operating expenses were flat.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

The $31.6 million increase in gross margin for 2011 is primarily due to an increase in NGL and condensate sales prices ($80.9 million), an increase fee based and other revenues ($2.3 million) and a decrease in product purchases ($31.7 million), partially offset by a decrease in natural gas sales prices ($23.9 million) and a decrease in commodity sales volumes ($59.4 million). The decrease in plant inlet volumes was largely attributable to a decline in traditional wellhead and leaner offshore supply volumes. The impact of the decrease in plant inlet was offset by incrementally adding volumes at facilities with higher recovery levels. Natural gas sales volumes decreased due to lower demand from our industrial customers and lower sales to other reportable segments for resale.

Operating expenses were flat.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	2011 vs. 2010 $ Change	2011 vs. 2010 % Change	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	2011 vs. 2010 $ Change	2011 vs. 2010 % Change
				($ in millions)				
Gross margin	$ 57.8	$ 40.8	$ 17.0	42%	$ 100.1	$ 78.5	$ 21.6	28%
Operating expenses	24.4	22.8	1.6	7%	44.4	49.2	(4.8)	(10%)
Operating margin	$ 33.4	$ 18.0	$ 15.4	86%	$ 55.7	$ 29.3	$ 26.4	90%
Operating statistics: (1)								
Fractionation volumes, MBbl/d	279.7	228.4	51.3	22%	244.7	219.0	25.7	12%
Treating volumes, MBbl/d	27.8	21.8	6.0	28%	19.1	14.7	4.4	30%

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

The $17.0 million increase in gross margin primarily reflects higher terminaling and storage revenue ($6.4 million) and increased fractionation volumes ($9.4 million). Terminaling and storage revenue is primarily due to increased supply services to petrochemical customers at our Mont Belvieu terminal, higher LPG exports at our Galena Park terminal, and a full quarter of operations of the recently acquired Channelview Terminal. The start-up and operation of the 78 MBbl/d expansion at the Cedar Bayou facility in the second quarter of 2011 resulted in higher throughput and increased gross margin.

The $1.6 million increase in operating expenses was primarily due to higher natural gas price for fuel to fractionators ($3.2 million), and higher costs associated with fractionation maintenance ($0.6 million), higher compensation and benefit costs ($1.4 million), contractor and professional services ($1.0 million), offset by a more favorable system product volume gain which was valued at higher 2011 NGL prices ($5.1 million).

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

The $21.6 million increase in gross margin reflects higher terminaling and storage revenue ($11.3 million) and increased fractionation volumes ($8.2 million). Terminaling and storage revenue is primarily due to increased supply services to petrochemical customers at our Mont Belvieu terminal, higher LPG exports at our Galena Park terminal, and a full quarter of operations in the second quarter of the recently acquired Channelview Terminal. The start-up and operation of the 78 MBbl/d expansion at the Cedar Bayou facility in the second quarter of 2011 resulted in higher throughput and increased gross margin.

The $4.8 million decrease in operating expenses was primarily due to a more favorable system product volume gain which was valued at higher 2011 NGL prices ($7.7 million), offset by higher natural gas price for fuel to fractionators ($2.3 million) and higher compensation and benefit costs ($1.9 million).

Marketing and Distribution

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	2011 vs. 2010 $ Change	2011 vs. 2010 % Change	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	2011 vs. 2010 $ Change	2011 vs. 2010 % Change
	($ in millions)							
Gross margin	$ 41.4	$ 24.9	$ 16.5	66%	$ 85.9	$ 55.8	$ 30.1	54%
Operating expenses	10.9	10.8	0.1	1%	22.8	22.0	0.8	4%
Operating margin	$ 30.5	$ 14.1	$ 16.4	116%	$ 63.1	$ 33.8	$ 29.3	87%
Operating statistics: (1)								
Natural gas sales, BBtu/d	857.5	668.3	189.2	28%	761.4	639.0	122.4	19%
NGL sales, MBbl/d	265.0	234.8	30.2	13%	268.7	240.6	28.1	12%
Average realized prices:								
Natural gas, $/MMBtu	4.28	4.10	0.18	4%	4.19	4.64	(0.45)	(10%)
NGL realized price, $/gal	1.35	1.03	0.32	31%	1.31	1.11	0.20	18%

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

The $16.5 million increase in gross margin was due to higher NGL volumes ($118.6 million) and natural gas volumes ($70.7 million), higher NGL prices ($326.2 million), higher natural gas prices ($13.8 million) and higher fee-based and other revenues ($13.1 million), offset by increased product purchases ($525.8 million). Factors contributing to a higher operating margin in 2011 included increased export sales and, and the positive impact of a contract settlement ($7.5 million) related to a multi-year propane exchange agreement. The contract, as restructured, may result in the receipt of future payments over the remaining term of the contract.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

The $30.1 million increase in gross margin was due to higher NGL volumes ($238.5 million), higher natural gas volumes ($102.8 million), higher NGL prices ($400.7 million) higher fee-based and other revenues ($14.4 million) offset by lower natural gas prices ($62.2 million), increased product purchases ($664.1 million). Factors contributing to a higher operating margin in 2011 included increased West Coast propane sales, increased export sales and the positive impact of a contract settlement ($7.5 million) related to a multi-year propane exchange agreement. The contract, as restructured, may result in the receipt of future payments over the remaining term of the contract.

Other

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Change	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Change
	(In Millions)					
Gross margin	$ (13.2)	$ 2.7	$ (15.9)	$ (17.6)	$ (0.3)	$ (17.3)
Operating margin	$ (13.2)	$ 2.7	$ (15.9)	$ (17.6)	$ (0.3)	$ (17.3)

Other contains the financial effects of our hedging program on profitability. The primary purpose of our commodity risk management activities is to hedge our exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. We have hedged the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes by entering into derivative financial instruments. As such, these hedge positions will enhance our margins in periods of falling prices and decrease our margins in periods of rising prices.

The following table provides a breakdown of our hedge results by product:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Change	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Change
	(In Millions)					
Natural Gas	$ 1.6	$ 5.9	$ (4.3)	$ 7.8	$ 7.0	$ 0.8
NGL	(13.3)	(2.6)	(10.7)	(22.2)	(6.3)	(15.9)
Crude	(1.5)	(0.6)	(0.9)	(3.2)	(1.0)	(2.2)
	$ (13.2)	$ 2.7	$ (15.9)	$ (17.6)	$ (0.3)	$ (17.3)

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness and to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for natural gas and NGLs, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under our senior secured credit facility, the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. Many financial institutions have had liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets.

We continue to evaluate counterparty risks related to our commodity derivative contracts and trade credit. We have all of our commodity derivatives with major financial institutions or major oil companies. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices, which could have a material adverse effect on our results of operation. We sell our natural gas, NGLs and condensate to a variety of purchasers. Non-performance by a trade creditor could result in losses.

Crude oil and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas and NGL equity volumes through 2013 and our condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. See “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.” The current market conditions may also impact our ability to enter into future commodity derivative contracts. A significant reduction in commodity prices could reduce our operating margins and cash flow from operations to the extent that such operating margins and cash flows derive from the portion of equity volumes that are not hedged.

We have experienced significant liability increases in the fair value of our commodity derivative instruments during 2011 compared to the year ended December 31, 2010. This change is attributable to increasing commodity prices and to additional hedged volumes during the first six months of 2011 compared to the volumes hedged as of December 31, 2010. For the six months ending June 30, 2011, we entered into additional derivative contracts that increased our hedged daily volumes of natural gas by 26,149 MMBtu, NGLs by 4,979 barrels and condensate by 2,335 barrels. The contracts extend to 2013 for natural gas and NGLs, and 2014 for condensate. We designated our commodity derivatives as cash flow hedges. Therefore, the impact to earnings as a result of the fair value changes is immaterial for the three and six months ended June 30, 2011 as these changes are recorded in Other Comprehensive Income ("OCI") until the underlying hedged transactions settle.

As of June 30, 2011, our liquidity of $888.8 million consisted of $73.1 million of available cash and $815.7 million of available borrowings under our credit facility. We will continue to monitor our liquidity and the credit markets. Additionally, we continue to monitor events and circumstances surrounding each of the lenders in our credit facility.

Our cash generated from operations has been sufficient to finance our operating expenditures and non-acquisition related capital expenditures. Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow and borrowings available under our senior secured credit facility should provide sufficient resources to finance our operations, non-acquisition related capital expenditures, long-term indebtedness obligations, collateral requirements and minimum quarterly cash distribution for at least the next twelve months.

A significant portion of our capital resources are utilized in the form of cash and letters of credit to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. At June 30, 2011, our total outstanding letter of credit postings were $86.3 million.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. We believe our cash flows provided by operating activities and availability under our credit facility will be sufficient to meet our operating requirements for the next twelve months.

Cash Flow

The following table and discussion summarize our consolidated cash flow provided by or used in operating activities, investing activities and financing activities for the periods indicated:

	Six Months Ended June 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change
	(In millions)			
Net cash provided by (used in):				
Operating activities	$ 252.7	$ 178.6	$ 74.1	41%
Investing activities	(170.1)	(43.7)	(126.4)	(289%)
Financing activities	(85.8)	(139.7)	53.9	39%

Operating Activities

Our Consolidated Statement of Cash Flows employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting our net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented. The following table displays our operating cash flows using the direct method as a supplement to the presentation in our financial statements.

	For the Six Months Ended June 30,		
	2011	2010	Variance
Cash flows from operating activities:			
Cash received from customers	$ 3,322.9	$ 2,798.5	$ 524.4
Cash received from (paid to) derivative counterparties (1)	(14.9)	15.9	(30.8)
Cash paid for:			
Product purchases	(2,802.6)	(2,426.0)	(376.6)
Operating expenses	(132.9)	(130.3)	(2.6)
General and administrative expenses (2)	(74.0)	(47.9)	(26.1)
Cash distributions from equity investment (3)	3.1	1.9	1.2
Interest paid	(46.5)	(31.8)	(14.7)
Income taxes paid	(2.2)	(1.6)	(0.6)
Other cash receipts (payments)	(0.2)	(0.1)	(0.1)
Net cash provided by operating activities	$ 252.7	$ 178.6	$ 74.1

(1) The change in cash paid to derivative counterparties reflects the change in our net position from in-the-money for the quarter ending June 30, 2010 to out-of-the-money for the quarter ending June 30, 2011. Our gross and operating margins for the six months ended June 30, 2010 included in Other for segment purposes reflect inflows of cash from counterparties offset by $16.2 million of non-cash expense items. These non-cash expense items are related to amortization of hedge termination fees (See Note 8 for more information) and hedge ineffectiveness.

(2) The increase in general and administrative cash payments results from higher 2011 intercompany settlements following the completion during April through September 2010 of the remaining asset drop downs.

(3) Total distributions received exceeded cumulative earnings. Therefore, $0.6 million in excess distributions over earnings were classified as an investing activity for the six months ended June 30, 2011.

Investing Activities

Net cash used in investing activities increased by $126.4 million for the six months ended June 30, 2011 compared to 2010. The increase was primarily driven by our acquisition of the Channelview Terminal for $29.0 million and a $76.0 million increase in expansion capital projects in gathering and processing assets and in fractionation assets. We also invested $6.0 million in equity contributions associated with the expansion at Gulf Coast Fractionators.

Financing Activities

Net cash used in financing activities decreased by $53.9 million for the six months ended June 30, 2011 compared to 2010. The decrease in net cash used in financing activities was driven by two primary factors: distributions and changes in our equity offerings and financing activities. For the six months ended June 30, 2011 compared to 2010, distributions increased by $31.1 million. Net proceeds from public offerings, issuance of senior notes and borrowings under our credit facility less repayments on our credit facility decreased from $60.5 million for the six months ended June 30, 2010 to $34.3 million for the six months ended June 30, 2011.

Our primary financing activities that occurred during the six months ended June 30, 2011 were:

- On January 24, 2011, we completed a public offering of 8,000,000 common units in us under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.2 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011 we issued an additional 1,200,000 common units, providing net proceeds of approximately $38.8 million. In addition, our general partner contributed $6.3 million to us for 187,755 general partner units to maintain its 2% general partner interest in us. We used the net proceeds from the offering to reduce borrowings under our senior secured credit facility.

- On February 2, 2011, we closed a private placement of $325.0 million in aggregate principal amount of our 6⅞% Notes resulting in net proceeds of $318.8 million.

- On February 4, 2011, we exchanged an additional $158.6 million principal amount of our 6⅞% Notes for $158.6 million aggregate principal amount of our 11¼% Notes. In conjunction with the exchange we paid a cash premium of $28.6 million including $0.9 million of accrued interest.

Net cash from the completion of the unit offering and the note offering less cash paid in connection with the exchange offer was used to reduce outstanding borrowings under our senior secured credit facility by $595.2 million.

Distributions to our Unitholders

Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Note 6 and Note 7 of the notes to Consolidated Financial Statements included in this Quarterly Report.

We intend to make cash distributions to our unitholders and our general partner of at least the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of June 30, 2011, such annual minimum amounts would have been approximately $101.0 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate. The quarterly distribution per limited partner unit paid in May 2011 for the first quarter of 2011 was $0.5575 per limited partner unit.

The following table shows the distributions for 2011 and 2010:

		Distributions (1)				
		Limited Partners	General Partner			
Date Paid	For the Three Months Ended	Common	Incentive	2%	Total	Distribution per limited partner unit
		(In millions, except per unit amounts)				
May 13, 2011	March 31, 2011	$ 47.3	$ 6.8	$ 1.1	$ 55.2	$ 0.5575
February 14, 2011	December 31, 2010	46.4	6.0	1.1	53.5	0.5475
November 12, 2010	September 30, 2010	40.6	4.6	0.9	46.1	0.5375
August 13, 2010	June 30, 2010	35.9	3.5	0.8	40.2	0.5275
May 14, 2010	March 31, 2010	35.2	2.8	0.8	38.8	0.5175
February 12, 2010	December 31, 2009	35.2	2.8	0.8	38.8	0.5175

(1) On July 11, 2011, we announced a cash distribution of $0.57 per common unit on our outstanding common units for the three months ended June 30, 2011, to be paid on August 12, 2011. The distribution to be paid is $41.7 million to our third-party limited partners, and $6.6 million, $7.8 million and $1.2 million to Targa for its ownership of common units, incentive distribution rights and its 2% general partner interest in us.

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Capital Requirements

The following table lists gross additions to property, plant and equipment, cash flows used in property, plant and equipment additions and the difference, which is primarily settled accruals and non-cash additions:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Gross additions to property, plant and equipment	$ 166.5	$ 45.9
Change in accruals	(1.8)	(0.1)
Cash expenditures	$ 164.7	$ 45.8

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. A significant portion of the cost of constructing new gathering lines to connect to our gathering system is generally paid for by the natural gas producer. However, we expect to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure and to enhance the value of our natural gas logistics and marketing assets.

We categorize our capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to our systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues.

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Capital expenditures:		
Expansion	$ 133.9	$ 28.8
Maintenance	32.6	17.1
	$ 166.5	$ 45.9

We estimate that our total capital expenditures for 2011 will be approximately $370 million gross and $335 million net of non-controlling interest share and reimbursements. We also estimate that of the $335 million net capital expenditures, approximately 20% will be for maintenance. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Major capital projects include:

- a $360 million expansion project at CBF to add an additional fractionator and related infrastructure enhancements at Mont Belvieu;
- a $40 million capital expansion project to expand the gathering and processing capability of our North Texas System;
- a $35 million benzene treatment project at Mont Belvieu to construct a treater designed to reduce benzene content of natural gasoline to meet new, more stringent environmental standards;
- a $30 million capital expansion project to expand the gathering and processing capability of our SAOU System;
- a $13 million expansion of our dock facilities and related infrastructure enhancements at Galena Park; and
- our portion of the $75 million expansion at Gulf Coast Fractionators, which is expected to be approximately $29 million.

These capital projects will extend through 2013. Future expansion capital expenditures may vary significantly based on investment opportunities.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our senior secured revolving credit facility, the issuance of additional common units and debt offerings.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For an in-depth discussion of market risks, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” in our Annual Report.

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, changes in interest rates, as well as nonperformance by our customers. We do not use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged. For an in-depth discussion of our hedging strategies, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk” in our Annual Report.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover specific NGL products based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Our NGL hedges’ fair values are based on published index prices for delivery at Mont Belvieu through 2013, except for the price of isobutane in 2012, which is based on the ending 2011 pricing. Our natural gas hedges’ fair values are based on published index prices for delivery at WAHA, Permian Basin and Mid-Continent, which closely approximate the actual NGL and natural gas delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

These commodity price hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Absent new federal regulations resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act, and as long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if our counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. A purchased put (or floor) transaction does not create credit exposure to us for our counterparties.

For all periods presented we have entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the three months ended June 30, 2011 and 2010 our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $(13.2) million and $2.7 million. During the six months ended June 30, 2011 and 2010 our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $(17.6) million and $(0.3) million.

As of June 30, 2011, we had the following hedge arrangements which will settle during the years ending December 31, 2011 through 2014 (except as indicated otherwise, the 2011 volumes reflect daily volumes for the period from July 1, 2011 through December 31, 2011):

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu per day 2011	2012	2013	Fair Value (In millions)
Swap	IF-WAHA	6.29	23,750			$ 8.5
Swap	IF-WAHA	6.61		14,850		10.6
Swap	IF-WAHA	5.28			7,230	0.9
Total Swaps			23,750	14,850	7,230	
Swap	IF-PB	4.58	6,565			0.4
Swap	IF-PB	4.98		10,200		1.5
Swap	IF-PB	5.23			7,084	0.9
Total Swaps			6,565	10,200	7,084	
Swap	IF-NGPL MC	5.66	8,155			2.0
Swap	IF-NGPL MC	6.03		6,740		3.5
Swap	IF-NGPL MC	4.89			2,775	-
Total Swaps			8,155	6,740	2,775	
Total Sales			38,470	31,790	17,089	
Natural Gas Basis Swaps						
Basis Swaps	Various Indexes, Maturities Through December 2012					0.1
						$ 28.4

NGL

Instrument Type	Index	Price $/Gal	Barrels per day 2011	2012	2013	Fair Value (In millions)
Swap	OPIS-MB	0.92	10,118			$ (26.2)
Swap	OPIS-MB	0.95		9,361		(24.2)
Swap	OPIS-MB	0.98			4,150	(8.4)
Total Swaps			10,118	9,361	4,150	
Floor	OPIS-MB	1.44	253			-
Floor	OPIS-MB	1.43		294		0.6
Total Floors			253	294	-	
Total Sales			10,371	9,655	4,150	
						$ (58.2)

Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2011	2012	2013	2014	Fair Value (In millions)
Swap	NY-WTI	87.87	1,730				$ (2.9)
Swap	NY-WTI	91.91		1,660			(5.2)
Swap	NY-WTI	93.34			1,795		(4.9)
Swap	NY-WTI	90.03				700	(2.6)
Total Sales			1,730	1,660	1,795	700	
							$ (15.6)

These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our NGL derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options based on inputs that are readily available in public markets. For the NGL contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those NGL contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the NGL valuations are classified as Level 3 within the fair value hierarchy. See Note 8 to the Consolidated Financial Statements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of variable rate borrowings under our senior secured revolving credit facility. To the extent that interest rates increase, interest expense for our revolving debt will also increase. As of June 30, 2011, we had variable rate borrowings of $198.0 million outstanding. In an effort to reduce exposure to changes in interest rates, we have entered into several interest rate swap and interest rate basis swap agreements. Under these agreements, the base interest rate on the specified notional amount (currently $300.0 million) of our variable rate debt is effectively fixed for the term of each agreement and ineffectiveness is required to be measured each reporting period for those contracts designated as hedging instruments.

All interest rate swaps and interest rate basis swaps had been designated as cash flow hedges of variable rate interest payments on borrowings under our senior secured revolving credit facility until February 11, 2011, when we de-designated $125.0 million notional principal of fixed interest rate swaps and $25.0 million notional principal of interest rate basis swaps. We de-designated the swaps as our borrowings under our credit facility reduced below $300.0 million, which is the total notional amount of our fixed interest rate swaps. The de-designated swaps receive mark-to-market treatment, with changes in fair value, cash and accrued settlements recorded to other income (expense).

As of June 30, 2011, we had the following open interest rate swaps:

Period	Fixed Rate	Notional Amount	Fair Value
Remainder of 2011	3.52%	$ 300	$ (5.0)
2012	3.40%	300	(7.1)
2013	3.39%	300	(6.3)
1/1/2014 - 4/24/2014	3.39%	300	(1.9)
			$ (20.3)

After taking into account our interest rate swaps that are designated as cash flow hedges, a hypothetical change of 100 basis points in the underlying interest rate of our variable rate debt would impact our annual interest expense by $0.2 million.

Counterparty Risk – Credit and Concentration

Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of June 30, 2011, affiliates of Barclays PLC ("Barclays") and Credit Suisse Group AG ("Credit Suisse") accounted for 57% and 11% of our counterparty credit exposure related to commodity derivative instruments. Barclays and Credit Suisse are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's Investors Service, Inc. and Standard & Poor's Corporation.

Customer Credit Risk. We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2011, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended June 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 11 – Commitments and Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this Item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Item 1A. Risk Factors” in our Annual Report. These risks and uncertainties are not the only ones facing us, and there may be additional matters of which we are unaware, or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations, as could the following:

Recently proposed rules regulating air emissions from oil and natural gas operations could cause us as well as natural gas exploration and production operators to incur increased capital expenditures and operating costs as well as cause us to experience reduced demand for our gathering, processing or fractionation services.

On July 28, 2011, the U.S. Environmental Protection Agency (“EPA”) proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA’s proposed rule package includes New Source Performance Standards (“NSPS”) to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA’s proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of “green completions” for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules combined with other federal and state rules that regulate air emissions that impact natural gas gathering and processing operations would establish new operating requirements for our business. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could require a number of modifications to our customer’s as well as our operations including the installation of new equipment. Compliance with such rules could result in significant costs as well as delays in well completions by our customers, including increased capital expenditures and operating costs, which may adversely impact our business. Moreover, the incurrence of such expenditures and costs by our exploration and production customers’ could result in reduced production by those customers and thus translate into reduced demand for our gathering, processing or fractionation services.

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. (Removed and Reserved.)

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's current report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Supplemental Indenture dated April 8, 2011 to Indenture dated June 18, 2008, among Targa Terminals LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 333-138747)).
4.2	Supplemental Indenture dated April 8, 2011 to Indenture dated July 6, 2009, among Targa Terminals LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 333-138747)).
4.3	Supplemental Indenture dated April 8, 2011 to Indenture dated August 13, 2010, among Targa Terminals LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 333-138747)).
4.4	Supplemental Indenture dated April 8, 2011 to Indenture dated February 2, 2011, among Targa Terminals LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 333-138747)).
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

** Furnished herewith

Signatures

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Authorized Officer and Principal Financial Officer)

Date: August 5, 2011

Exhibit Index

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31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	Filed herewith
**	Furnished herewith

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Rene R. Joyce, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the six months ended June 30, 2011 of Targa Resources Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 5, 2011

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Matthew J. Meloy, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the six months ended June 30, 2011 of Targa Resources Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 5, 2011

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP
(Principal Financial Officer)

Exhibit 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**

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the six months ended June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Rene R. Joyce, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: August 5, 2011

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 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**

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the six months ended June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy , as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: August 5, 2011

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.