Targa Resources Corp.
Form 10-Q
November 07, 2011

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

FORM 10-Q

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

For the quarterly period ended September 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: 001-34991

TARGA RESOURCES CORP.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-3701075 (I.R.S. Employer Identification No.)
1000 Louisiana St, Suite 4300, Houston, Texas (Address of principal executive offices)	77002 (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 R No £.

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

Large accelerated filer £	Accelerated filer £	Non-accelerated filer R (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 November 1, 2011, there were 42,400,818 shares of the registrant's common stock, $0.001 par value, outstanding.

PART I—FINANCIAL INFORMATION

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, other than Targa Resources Partners LP, collectively "we," "us," "Targa," "TRC," or the "Company") 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 within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," " 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 ("Quarterly Report") as well as the following risks and uncertainties:

- Targa Resources Partners LP's (the "Partnership") and 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 the Partnership's transactions;
- the Partnership's success in risk management activities, including the use of derivative financial instruments to hedge commodity 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 the Partnership's services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- the Partnership's ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around the Partnership's assets and its success in connecting natural gas supplies to its gathering and processing systems and NGL supplies to its logistics and marketing facilities;
- the Partnership's and 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.

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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
/hr	Per hour
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

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	September 30, 2011	December 31, 2010
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 154.1	$ 188.4
Trade receivables, net of allowances of $2.2 million and $7.9 million	544.5	466.6
Inventory	139.4	50.4
Deferred income taxes	-	3.6
Assets from risk management activities	35.2	25.2
Other current assets	17.5	16.3
Total current assets	890.7	750.5
Property, plant and equipment, at cost	3,572.2	3,331.4
Accumulated depreciation	(955.4)	(822.4)
Property, plant and equipment, net	2,616.8	2,509.0
Long-term assets from risk management activities	20.8	18.9
Other long-term assets	262.1	115.4
Total assets	$ 3,790.4	$ 3,393.8
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 298.9	$ 254.2
Accrued liabilities	339.7	335.8
Deferred income taxes	0.2	-
Liabilities from risk management activities	34.7	34.2
Total current liabilities	673.5	624.2
Long-term debt	1,603.4	1,534.7
Long-term liabilities from risk management activities	10.7	32.8
Deferred income taxes	117.6	111.6
Other long-term liabilities	52.7	54.4
Commitments and contingencies (see Note 13)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized, 42,400,818 and 42,292,348 shares issued and outstanding as of September 30, 2011 and December 31, 2010)	-	-
	-	-

Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of September 30, 2011 and December 31, 2010)				
Additional paid-in capital		243.9		244.5
Accumulated deficit		(78.6)		(100.8)
Accumulated other comprehensive income		0.4		0.6
Total Targa Resources Corp. stockholders' equity		165.7		144.3
Noncontrolling interests in subsidiaries		1,166.8		891.8
Total owners' equity		1,332.5		1,036.1
Total liabilities and owners' equity	$	3,790.4	$	3,393.8

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Unaudited) (In millions, except per share amounts)			
Revenues	$1,713.6	$1,220.0	$5,060.5	$3,948.3
Costs and expenses:				
Product purchases	1,485.5	1,033.7	4,364.5	3,393.9
Operating expenses	76.5	66.2	214.1	190.4
Depreciation and amortization expenses	45.7	50.2	134.3	136.9
General and administrative expenses	35.4	27.0	105.1	81.0
Other	(0.3)	(0.4)	(0.3)	(0.4)
	1,642.8	1,176.7	4,817.7	3,801.8
Income from operations	70.8	43.3	242.8	146.5
Other income (expense):				
Interest expense, net	(26.8)	(30.0)	(83.3)	(83.9)
Equity in earnings of unconsolidated investment	2.2	1.1	5.2	3.8
Loss on debt repurchases (see Note 6)	-	-	-	(17.4)
Gain (loss) on early debt extinguishment, net (see Note 6)	-	(10.6)	-	8.1
Loss on mark-to-market derivative instruments	(1.8)	(0.1)	(5.0)	(0.4)
Other income (expense), net	(0.5)	0.6	(0.6)	0.8
Income before income taxes	43.9	4.3	159.1	57.5
Income tax benefit (expense):				
Current	2.5	0.8	(7.6)	(0.9)
Deferred	(9.9)	(9.4)	(10.9)	(17.6)
	(7.4)	(8.6)	(18.5)	(18.5)
Net income (loss)	36.5	(4.3)	140.6	39.0
Less: Net income attributable to noncontrolling interests	31.6	13.2	118.4	46.2
Net income (loss) attributable to Targa Resources Corp.	4.9	(17.5)	22.2	(7.2)
Dividends on Series B preferred stock	-	(1.4)	-	(8.4)
Dividends on common equivalents	-	-	-	(177.8)
Net income (loss) available to common shareholders	$4.9	$(18.9)	$22.2	$(193.4)
Net income (loss) available per common share - basic	$0.12	$(3.77)	$0.54	$(45.00)
Net income (loss) available per common share - diluted	$0.12	$(3.77)	$0.54	$(45.00)
Weighted average shares outstanding - basic	41.0	5.0	41.0	4.3
Weighted average shares outstanding - diluted	41.5	5.0	41.4	4.3

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Unaudited) (In millions)			
Net income (loss) attributable to Targa Resources Corp.	$4.9	$(17.5)	$22.2	$(7.2)
Other comprehensive income (loss) attributable to Targa Resources Corp.				
Commodity hedging contracts:				
Change in fair value	7.3	(0.8)	(1.3)	44.3
Settlements reclassified to revenues	0.8	(1.7)	0.4	(1.8)
Interest rate swaps:				
Change in fair value	(0.4)	(1.2)	(0.4)	(3.1)
Settlements reclassified to interest expense, net	0.2	0.6	0.9	1.7
Related income taxes	(3.1)	(1.7)	0.2	(19.8)
Other comprehensive income (loss) attributable to Targa Resources Corp.	4.8	(4.8)	(0.2)	21.3
Comprehensive income (loss) attributable to Targa Resources Corp.	9.7	(22.3)	22.0	14.1
Net income attributable to noncontrolling interests	31.6	13.2	118.4	46.2
Other comprehensive income (loss) attributable to noncontrolling interests				
Commodity hedging contracts:				
Change in fair value	39.7	(0.9)	(8.5)	44.0
Settlements reclassified to revenues	8.7	(5.9)	22.6	(6.2)
Interest rate swaps:				
Change in fair value	(1.9)	(5.5)	(3.9)	(20.6)
Settlements reclassified to interest expense, net	0.8	2.9	4.8	6.8
Other comprehensive income (loss) attributable to noncontrolling interests	47.3	(9.4)	15.0	24.0
Comprehensive income attributable to noncontrolling interests	78.9	3.8	133.4	70.2
Total comprehensive income (loss)	$88.6	$(18.5)	$155.4	$84.3

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENT OF CHANGES IN OWNERS' EQUITY

	Common Stock		Additional Paid in	Accumulated	Accumulated Other Comprehensive Income	Non Controlling	
	Shares	Amount	Capital	Deficit	(Loss)	Interests	Total
			(Unaudited)				
			(In millions, except shares in thousands)				
Balance, December 31, 2010	42,292	$ -	$ 244.5	$ (100.8)	$ 0.6	$ 891.8	$ 1,036.1
Compensation on equity grants	109	-	10.7	-	-	0.7	11.4
Sale of Partnership limited partner interests	-	-	-	-	-	298.0	298.0
Impact of Partnership equity transactions	-	-	15.1	-	-	(15.1)	-
Dividends	-	-	(26.4)	-	-	-	(26.4)
Distributions to noncontrolling interests	-	-	-	-	-	(142.0)	(142.0)
Other comprehensive income (loss)	-	-	-	-	(0.2)	15.0	14.8
Net income	-	-	-	22.2	-	118.4	140.6
Balance, September 30, 2011	42,401	$ -	$ 243.9	$ (78.6)	$ 0.4	$ 1,166.8	$ 1,332.5

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2011	2010
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$140.6	$39.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	7.2	6.2
Paid-in-kind interest expense	-	9.0
Compensation on equity grants	11.4	0.5
Depreciation and amortization expense	134.3	136.9
Accretion of asset retirement obligations	2.7	2.4
Deferred income tax expense	10.9	17.6
Equity in earnings of unconsolidated investment, net of distributions	(1.4)	-
Risk management activities	(18.8)	(16.5)
Gain on sale of assets	(0.4)	(0.4)
Loss on debt repurchases	-	17.4
Gain on early debt extinguishment	-	(8.1)
Changes in operating assets and liabilities:		
Receivables and other assets	(75.3)	(7.7)
Inventory	(86.9)	(16.0)
Accounts payable and other liabilities	40.3	(54.3)
Net cash provided by operating activities	164.6	126.0
Cash flows from investing activities		
Outlays for property, plant and equipment	(214.3)	(84.2)
Business acquisitions	(164.2)	-
Investment in unconsolidated affiliate	(11.9)	-
Unconsolidated affiliate distributions in excess of accumulated earnings	-	1.1
Other	0.3	2.4
Net cash used in investing activities	(390.1)	(80.7)
Cash flows from financing activities		
Partnership loan facilities:		
Borrowings	1,426.0	1,178.1
Repayments	(1,656.3)	(904.0)
Proceeds from issuance of senior notes	325.0	250.0
Cash paid on note exchange	(27.7)	-
Non-Partnership loan facilities:		
Borrowings	-	495.0
Repayments	-	(949.5)
Costs incurred in connection with financing arrangements	(6.2)	(39.5)
Distributions to noncontrolling interests	(142.0)	(101.2)
Proceeds from sale of Partnership interests	-	224.7
Partnership equity transactions	298.0	317.8
Repurchases of common stock	-	(0.1)
Stock options exercised	-	0.9
Dividends to common and common equivalent shareholders	(25.6)	(200.0)

Dividends to preferred shareholders	-	(219.9)
Net cash provided by financing activities	191.2	52.3
Net change in cash and cash equivalents	(34.3)	97.6
Cash and cash equivalents, beginning of period	188.4	252.4
Cash and cash equivalents, end of period	$154.1	$350.0

See notes to consolidated financial statements

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TARGA RESOURCES CORP.
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 where otherwise noted, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 — Organization

Targa Resources Corp. ("TRC") is a Delaware corporation formed in October 2005. Our common stock is listed on the New York Stock Exchange under the symbol "TRGP." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Targa" are intended to mean our consolidated business and operatio including our wholly-owned subsidiary TRI Resources Inc. ("TRI").

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 nine months ended September 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 nine months ended September 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.

Targa Resources GP LLC (the "General Partner"), an indirect wholly owned subsidiary of ours, is the general partner of Targa Resources Partners LP (the "Partnership"). Because we control the General Partner of the Partnership, under GAAP, we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership's financial results in our consolidated financial statements, even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by our controlled affiliates are reflected in our results of operations as net income attributable to non-controlling interests and in our balance sheet equity section as noncontrolling interests in subsidiaries. Throughout these footnotes, we make a distinction where relevant between financial results of the Partnership versus those of a standalone parent and its non-partnership subsidiaries.

As of September 30, 2011, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;

- all Incentive Distribution Rights; and

- 11,645,659 common units of the Partnership, representing a 13.7% limited partnership interest.

The Partnership is 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. See Note 15 for an analysis of our and the Partnership's operations by segment.

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Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies followed by the Company 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 nine months ended September 30, 2011.

2011 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.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment. The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, allows entities to first assess qualitative factors when testing goodwill for impairment. Early adoption is permitted. Adoption of this amendment has no impact on our current financial presentation.

Note 4 – Partnership Business Acquisitions

On March 15, 2011, the Partnership acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel (the "Channelview Terminal") for $29.0 million. The Channelview Terminal, with storage capacity of 544,000 barrels, can handle multiple grades of blend stocks, petroleum products and crude and has potential for expansion, as well as integration with the Partnership’s other logistics operations.

On September 30, 2011 the Partnership acquired two refined petroleum products and crude oil storage and terminaling facilities. The facility on the Hylebos Waterway in the Port of Tacoma, Washington has 758,000 barrels of capacity and handles refined petroleum products, LPGs and biofuels, including ethanol and biodiesel. The facility on the Patapsco River in Baltimore, Maryland has approximately 505,000 barrels of storage capacity. Both terminals contain blending and heating capabilities, and have tanker truck and barge loading and unloading infrastructure. Total consideration for both facilities was $127.7 million plus an additional $7.5 million for estimated working capital and has been included in the Partnership’s other long-term assets in the Partnership’s September 30, 2011 balance sheet pending finalization of fair value accounting under ASC 805.

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Note 5 — Property, Plant and Equipment

	September 30, 2011			December 31, 2010			
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Estimated Useful Lives (In Years)
Natural gas gathering systems	$1,710.9	$-	$ 1,710.9	$1,630.9	$-	$ 1,630.9	5 to 20
Processing and fractionation facilities	1,058.4	6.6	1,065.0	961.9	6.6	968.5	5 to 25
Terminaling and storage facilities	272.7	-	272.7	244.7	-	244.7	5 to 25
Transportation assets	275.5	-	275.5	275.6	-	275.6	10 to 25
Other property, plant and equipment	51.2	22.6	73.8	46.8	22.6	69.4	3 to 25
Land	53.2	-	53.2	51.2	-	51.2	-
Construction in progress	116.6	4.5	121.1	88.4	2.7	91.1	-
	$3,538.5	$33.7	$ 3,572.2	$3,299.5	$31.9	$ 3,331.4	

Note 6 — Debt Obligations

	September 30, 2011	December 31, 2010
Long-term debt:		
Non-Partnership obligations:		
TRC Holdco loan facility, variable rate, due February 2015	$ 89.3	$ 89.3
TRI Senior secured revolving credit facility, variable rate, due July 2014 (1)	-	-
Obligations of the Partnership: (2)		
Senior secured revolving credit facility, variable rate, due July 2015 (3)	535.0	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 discount	(3.0)	(10.3)
Senior unsecured notes, 7 % fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6	-
Unamortized discount	(33.3)	-
Total long-term debt	$ 1,603.4	$ 1,534.7
Irrevocable standby letters of credit:		
Letters of credit outstanding under TRI Senior secured credit facility (1)	$ -	$ -
Letters of credit outstanding under the Partnership Senior secured revolving credit facility (3)	88.3	101.3
	$ 88.3	$ 101.3

(1) As of September 30, 2011, the entire amount of TRI's $75.0 million credit facility was available for letters of credit and available capacity under this facility was $75.0 million.

(2) While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(3) As of September 30, 2011, availability under the Partnership's $1.1 billion senior secured revolving credit facility was $476.7 million.

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The following table shows the range of interest rates paid and weighted average interest rate paid on our and the Partnership's variable-rate debt obligations during the nine months ended September 30, 2011:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
TRC Holdco loan facility	3.2% - 3.3%	3.3%
TRI Senior secured term loan facility, due 2014	N/A	N/A
Partnership Senior secured revolving credit facility	2.4% - 4.8%	2.7%

Compliance with Debt Covenants

As of September 30, 2011, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Holdco Credit Agreement

During the nine months ended September 30, 2010, we completed transactions that have been recognized in our consolidated financial statements as a debt extinguishment, and recognized a pretax gain of $32.8 million. The transactions included payments of $131.4 million to acquire $164.2 million of outstanding borrowings under our Holdco credit agreement and write offs of associated debt issue costs totaling $1.2 million.

TRI Senior Secured Credit Agreement

During the nine months ended September 30, 2010, we incurred a loss on debt repurchases of $17.4 million comprising $10.9 million of premiums paid and $6.5 million from the write-off of debt issue costs related to the repurchase of our 8½% senior notes. The premiums paid were included as a cash outflow from a financing activity in the Statement of Cash Flows.

During the nine months ended September 30, 2010, we also incurred a loss on debt extinguishments of $12.9 million from the write-off of debt issue costs related to the repayments of our term loan and terminations of our synthetic letter of credit and revolving credit facilities.

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Partnership 6 % Senior Notes

On February 2, 2011, the Partnership closed a private placement of $325.0 million in aggregate principal amount of 6 % Senior Notes due 2021 (the “6 % Notes”). The net proceeds of this offering were $318.8 million after deducting expenses of the offering. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility and for general partnership purposes.

On February 4, 2011, the Partnership exchanged an additional $158.6 million principal amount of its 6 % Notes plus payments of $28.6 million including $0.9 million of accrued interest for $158.6 million aggregate principal amount of its 11¼% Senior Notes due 2017 (the “11¼% Notes”). The holders of the exchanged Notes are subject to the provisions of the 6 % Notes described below. The debt covenants related to the remaining $72.7 million of face value of the 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 6 % Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness, including indebtedness under the Partnership’s credit facility. They are senior in right of payment to any of the Partnership’s future subordinated indebtedness and are unconditionally guaranteed by certain of the Partnership’s subsidiaries. These notes are effectively subordinated to all secured indebtedness under the Partnership’s credit agreement, which is secured by substantially all of the Partnership’s assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 6 % Notes accrues at the rate of 6 % per annum and is payable semi-annually in arrears on February 1 and August 1, commencing on August 1, 2011.

The Partnership may redeem 35% of the aggregate principal amount of the 6 % Notes at any time prior to February 1, 2014, with the net cash proceeds of one or more equity offerings. The Partnership 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 6 % Notes (excluding 6 % Notes held by the Partnership) 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.

The Partnership may also redeem all or part of the 6 % Notes on or after August 1, 2016 at the prices set forth below plus accrued and unpaid interest and liquidated damages, if any. Redemption periods begin on August 1 of each year indicated below:

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

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Note 7 — Partnership Units and Related Matters

Partnership Equity

On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units representing limited partner interests in the Partnership ("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, the Partnership issued an additional 1,200,000 common units, providing net proceeds of $38.8 million. In addition, we contributed $6.3 million to the Partnership for 187,755 general partner units to maintain our 2% interest in the Partnership.

Distributions

Distributions for the nine months ended September 30, 2011 and 2010 were as follows:

		Distributions					
	For the Three Months	Limited Partners	General Partner			Distributions to Targa Resources	Distributions per limited
Date Paid	Ended	Common	Incentive	2%	Total	Corp.	partner unit
		(In millions, except per unit amounts)					
August 12, 2011	June 30, 2011	$ 48.3	$ 7.8	$ 1.2	$ 57.3	$ 15.6	$ 0.5700
May 13, 2011	March 31, 2011	47.3	6.8	1.1	55.2	14.4	0.5575
February 14, 2011	December 31, 2010	46.4	6.0	1.1	53.5	13.5	0.5475
November 12, 2010	September 30, 2010	40.6	4.6	0.9	46.1	11.8	0.5375
August 13, 2010	June 30, 2010	35.9	3.5	0.8	40.2	10.4	0.5275
May 14, 2010	March 31, 2010	35.2	2.8	0.8	38.8	9.6	0.5175
February 12, 2010	December 31, 2009	35.2	2.8	0.8	38.8	14.0	0.5175

Subsequent Event. On October 11, 2011, the Partnership announced a cash distribution of $0.5825 per common unit on its outstanding common units for the three months ended September 30, 2011, to be paid on November 14, 2011. The distribution to be paid is $42.6 million to the Partnership's third-party limited partners, and $6.8 million, $8.8 million and $1.2 million to Targa for its ownership of common units, incentive distribution rights and its 2% general partner interest in the Partnership.

Note 8 — Common Stock and Related Matters

Secondary Offering

On April 26, 2011, certain of our stockholders sold, in a secondary public offering, 5,650,000 shares of our common stock under a registration statement on Form S-1 at a price of $31.73 per share of common stock ($30.65 per share, net of underwriting discounts), providing additional net proceeds of $173.2 million to selling stockholders. We received no proceeds from the sale of shares by the selling stockholders. Pursuant to the exercise of the underwriters' overallotment option, selling stockholders also sold an additional 847,500 shares of our common stock, providing net proceeds of $26.0 million. We incurred approximately $0.6 million of expenses in connection with the offering, including all expenses of the selling stockholders which we have paid.

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Dividends

Dividends since our initial public offering on December 10, 2010 through September 30, 2011 were as follows:

Date Paid	For the Three Months Ended	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
		(In millions, except per share amounts)			
August 16, 2011	June 30, 2011	$ 12.3	$ 11.9	$ 0.4	$ 0.2900
May 13, 2011	March 31, 2011	11.5	11.2	0.3	0.2725
February 14, 2011	December 31, 2010	2.6	2.5	0.1	0.0616 (2)

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.
(2) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

Subsequent Event. On October 11, 2011, we announced a quarterly dividend of $0.3075 per share of our common stock on our outstanding common stock for the three months ended September 30, 2011, to be paid on November 15, 2011.

Note 9 — Earnings per Common Share

The following table sets forth a reconciliation of net income and weighted average shares outstanding used in computing basic and diluted net income per common share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	$ 36.5	$ (4.3)	$ 140.6	$ 39.0
Less: Net income attributable to noncontrolling interest	31.6	13.2	118.4	46.2
Net income attributable to Targa Resources Corp.	4.9	(17.5)	22.2	(7.2)
Dividends on Series B preferred stock	-	(1.4)	-	(8.4)
Dividends to common equivalents	-	-	-	(177.8)
Net income attributable to common shareholders	$ 4.9	$ (18.9)	$ 22.2	$ (193.4)
Weighted average shares outstanding - basic	41.0	5.0	41.0	4.3
Net income (loss) available per common share - basic	$ 0.12	$ (3.77)	$ 0.54	$ (45.00)
Weighted average shares outstanding	41.0	5.0	41.0	4.3
Dilutive effect of unvested stock awards	0.5	-	0.4	-
Weighted average shares outstanding - diluted	41.5	5.0	41.4	4.3
Net income (loss) available per common share - diluted	$ 0.12	$ (3.77)	$ 0.54	$ (45.00)

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Note 10 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of the Partnership's commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in the Partnership's operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of cash flows, the Partnership has hedged the commodity price associated with a portion of its 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 the Partnership's physical equity volumes. The NGL hedges cover baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon the Partnership's 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 the Partnership's actual NGL and natural gas delivery points.

The Partnership hedges a portion of its 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 the Partnership to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of its underlying West Texas condensate equity volumes.

At September 30, 2011, the notional volumes of the Partnership's 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

The Partnership frequently enters into derivative instruments to manage location basis differentials with short-term fractionation arrangements. Based on the current application of the basis derivatives, the Partnership does not account for these derivatives as hedges and records changes in fair value and cash settlements to revenues.

Interest Rate Swaps

On September 6, 2011, the Partnership paid $24.2 million, including $1.2 million in accrued interest, to terminate all of its interest rate swaps. The interest rate swaps were originally entered into to mitigate interest rate risk on the Partnership's senior secured revolving credit facility. A total of $19.6 million in losses are deferred in other comprehensive income ("OCI"). As long as the Partnership maintains variable rate debt through its senior secured revolving credit facility, this deferred loss will be amortized into interest expense over the original terms of the swap contracts, which extend to April 2014.

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

	Derivative Assets		Derivative Liabilities
Balance	Fair Value as of	Balance	Fair Value as of

	Sheet Location	September 30, 2011	December 31, 2010	Sheet Location	September 30, 2011	December 31, 2010
Designated as hedging instruments						
Commodity contracts	Current assets	$ 34.7	$ 24.8	Current liabilities	$ 34.6	$ 25.5
	Long-term assets	20.8	18.9	Long-term liabilities	10.7	20.5
Interest rate contracts	Current assets	-	-	Current liabilities	-	7.8
	Long-term assets	-	-	Long-term liabilities	-	12.3
Total designated as hedging instruments		$ 55.5	$ 43.7		$ 45.3	$ 66.1
Not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.5	$ 0.4	Current liabilities	$ 0.1	$ 0.9
	Long-term assets	-	-	Long-term liabilities	-	-
Total not designated as hedging instruments		$ 0.5	$ 0.4		$ 0.1	$ 0.9
Total derivatives		$ 56.0	$ 44.1		$ 45.4	$ 67.0

The fair value of the Partnership’s 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.

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The following tables reflect amounts recorded in OCI, amounts reclassified from OCI to revenue and expense and amounts recognized in income on the ineffective portion of the Partnership's hedges:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Interest rate contracts	$(2.3)	$(6.7)	$(4.3)	$(23.7)
Commodity contracts	47.0	(1.7)	(9.8)	88.3
	$44.7	$(8.4)	$(14.1)	$64.6

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	2011	2010	2011	2010
Interest expense, net	$(1.0)	$(3.5)	$(5.7)	$(8.5)
Revenues	(9.5)	7.6	(23.0)	8.0
	$(10.5)	$4.1	$(28.7)	$(0.5)

	Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	2011	2010	2011	2010
Revenues	$0.2	$0.4	$0.2	$0.1

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Our consolidated 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 nine months ended September 30, 2011 and 2010, we recorded the following mark-to-market gains (losses):

Derivatives Note Designated As Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives: Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Commodity contracts	Revenue	$ 0.4	$ (0.2)	$ 1.4	$ (0.9)
Commodity contracts	Other income (expense)	-	(0.1)	-	(0.4)
Interest rate swaps	Other income (expense)	(1.8)	-	(5.0)	-
		$ (1.4)	$ (0.3)	$ (3.6)	$ (1.3)

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

	September 30, 2011	December 31, 2010
Unrealized gain on commodity hedges, before tax	$3.5	$4.5
Unrealized gain on commodity hedges, net of tax	2.1	2.7
Unrealized loss on interest rate swaps, before tax	(2.9)	(3.4)
Unrealized loss on interest rate swaps, net of tax	(1.7)	(2.1)

As of September 30, 2011, deferred net losses of $7.2 million on commodity hedges and $8.4 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

In July 2008, Targa and the Partnership paid $9.6 million and $77.8 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. Targa and the Partnership also entered into new natural gas and NGL commodity swaps at then current market prices that matched the production volumes of the terminated swaps. Prior to the terminations, these swaps were designated as cash flow hedges. During the three and nine months ended September 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 nine months ended September 30, 2010, $7.1 million and $22.2 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 11 for additional disclosures related to derivative instruments and hedging activities.

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Note 11 — Fair Value Measurements

We categorize the inputs to the fair value of 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 to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative instruments consist of financially settled commodity swap and option contracts and fixed price commodity contracts with certain counterparties. The Partnership determines the value of its 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. The Partnership has consistently applied these valuation techniques in all periods presented and we believe the Partnership has obtained the most accurate information available for the types of derivative contracts the Partnership holds.

The following tables present the fair value of the Partnership's 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. The Partnership's 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.

	September 30, 2011			
	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$56.0	$-	$56.0	$-
Total assets	$56.0	$-	$56.0	$-
Liabilities from commodity derivative contracts	$45.4	$-	$45.4	$-
Total liabilities	$45.4	$-	$45.4	$-
	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 the Partnership's financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts
Balance, December 31, 2010	$(11.6)
Settlements included in Net Income	3.7

Transfers out of Level 3	7.9
Balance, September 30, 2011	$-

The Partnership transferred $7.9 million in derivative liabilities from Level 3 to Level 2 for the nine months ended September 30, 2011. The transfer is attributable to increased transparency and liquidity in the NGL markets, specifically with regard to 2013 prices.

The Partnership designates 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 12 — 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 the 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 the senior secured revolving credit facilities approximate their fair value, as its interest rate is based on prevailing market rates. The fair value of the Partnership's senior unsecured notes is based on quoted market prices based on trades of such debt as of the dates indicated in the following table:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Holdco loan facility (1)	$89.3	$87.5	$89.3	$86.8
Senior unsecured notes of the Partnership, 8¼% fixed rate	209.1	218.6	209.1	219.4
Senior unsecured notes of the Partnership, 11¼% fixed rate	69.7	81.8	221.0	253.2
Senior unsecured notes of the Partnership, 7 % fixed rate	250.0	258.4	250.0	259.7
Senior unsecured notes of the Partnership, 6 % fixed rate	450.3	467.6	N/A	N/A

(1) The Holdco loan is not widely held, and we are not able to obtain an indicative quote from external sources. The December 31, 2010 fair value was based on the November 2010 repurchases. The September 30, 2011 fair value is based on management's consideration of changes in settlement value given the trades that took place in November 2010.

Note 13 — 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.

The Partnership's environmental liability at September 30, 2011 and December 31, 2010 was $1.4 million and $1.6 million. The Partnership's September 30, 2011 liability was for ground water assessment and remediation.

In May 2007, the New Mexico Environment Department ("NMED") alleged air emissions violations at the Eunice, Monument and Saunders gas processing plants, which are operated by the Partnership and owned by Versado Gas Processors, LLC ("Versado"), a joint venture that owns these plants and in which the Partnership owns a 63% interest, 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 the Partnership's portion of the cost is projected to be $21.0 million. As of September 30, 2011, Versado's project expenditures total $21.1 million, of which the Partnership's share was $13.3 million. Under the terms of the Versado acquisition purchase and sale agreement between us and the Partnership, we are obligated to reimburse the Partnership for maintenance capital expenditures required pursuant to the NMED settlement agreement.

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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 14 — Supplemental Cash Flow Information

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Interest paid	$35.1	$32.4	$83.7	$80.4
Taxes paid	0.1	54.4	34.2	58.5
Non-cash adjustment to line-fill	-	(0.1)	(2.1)	0.4

Note 15 — Segment Information

With the conveyance of all of our remaining operating assets to the Partnership in September 2010, all operating assets are now owned by the Partnership.

The Partnership reports its 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 the Partnership's hedging activities are reported in Other.

The Partnership's 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 NGLs 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.

The Partnership's Logistics and Marketing division is also referred to as the Downstream Business. The Downstream Business includes all the activities necessary to convert raw NGLs 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 the Partnership's other operations.

The Partnership's Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling crude and refined petroleum products. These assets are generally connected to, and supplied in part by, the Partnership's 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 Partnership's 2011 acquisitions of refined petroleum products and crude storage and terminaling facilities.

The Partnership's Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes: (1) marketing the Partnership's NGL production and purchasing NGL 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 the Partnership from the Partnership’s Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

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

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Segment information is shown in the following tables. We have segregated the following segment information between Partnership and non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions between Targa and the Partnership as if they occurred in prior periods similar to a pooling of interests. The non-Partnership results include activities related to certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected under GAAP in the Partnership common control results.

	Three Months Ended September 30, 2011							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$47.9	$ 75.2	$-	$ 1,530.3	$(10.8)	$ 0.1	$ 1.0	$ 1,643.7
Fees from midstream services	7.0	3.6	35.5	15.8	-	-	-	61.9
Other	(0.2)	0.3	0.3	7.7	-	-	(0.1)	8.0
	54.7	79.1	35.8	1,553.8	(10.8)	0.1	0.9	1,713.6
Intersegment revenues								
Sales of commodities	385.4	242.9	0.1	186.0	-	(814.4)	-	-
Fees from midstream services	0.2	-	24.2	1.8	-	(26.2)	-	-
Other	-	-	-	7.0	-	(7.0)	-	-
	385.6	242.9	24.3	194.8	-	(847.6)	-	-
Revenues	$440.3	$ 322.0	$60.1	$ 1,748.6	$(10.8)	$ (847.5)	$ 0.9	$ 1,713.6
Operating margin	$71.8	$ 39.8	$30.1	$ 19.7	$(10.8)	$ 0.1	$ 0.9	$ 151.6
Other financial information:								
Total assets	$1,647.3	$ 425.2	$713.2	$ 702.3	$56.0	$ 78.0	$ 168.4	$ 3,790.4
Capital expenditures (1)	$40.2	$ 4.2	$165.0	$ 0.6	$-	$ 0.8	$ 0.5	$ 211.3

(1) Logistics Assets segment capital expenditures includes petroleum logistics acquisitions. See Note 4.

	Three Months Ended September 30, 2010							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sale of commodities	$42.2	$ 109.1	$-	$ 1,013.6	$7.1	$ (0.1)	$ 0.3	$ 1,172.2

Fees from midstream services	6.2	3.4	23.2	9.6	-	-	-	42.4
Other	(0.5)	0.8	-	3.7	-	0.1	1.3	5.4
	47.9	113.3	23.2	1,026.9	7.1	-	1.6	1,220.0
Intersegment revenues								
Sale of commodities	253.4	163.2	0.2	113.3	-	(530.1)	-	-
Fees from midstream services	0.3	-	19.7	0.2	-	(20.2)	-	-
Other	-	-	-	5.0	-	(5.0)	-	-
	253.7	163.2	19.9	118.5	-	(555.3)	-	-
Revenues	$301.6	$ 276.5	$43.1	$ 1,145.4	$7.1	$ (555.3)	$ 1.6	$ 1,220.0
Operating margin	$49.6	$ 23.5	$23.6	$ 15.0	$7.1	$ -	$ 1.3	$ 120.1
Other financial information:								
Total assets	$1,627.7	$ 448.5	$432.7	$ 426.4	$65.4	$ 62.3	$ 397.0	$ 3,460.0
Capital expenditures	$13.6	$ 2.0	$19.3	$ 1.2	$-	$ -	$ 0.7	$ 36.8

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Nine Months Ended September 30, 2011

	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sale of commodities	$145.3	$ 243.9	$0.1	$ 4,505.5	$(28.4)	$ -	$ 3.8	$ 4,870.2
Fees from midstream services	19.4	12.5	91.3	37.3	-	-	-	160.5
Other	0.2	0.9	0.8	24.8	-	0.2	2.9	29.8
	164.9	257.3	92.2	4,567.6	(28.4)	0.2	6.7	5,060.5
Intersegment revenues								
Sale of commodities	1,051.8	704.9	0.4	465.9	-	(2,223.0)	-	-
Fees from midstream services	0.7	0.4	67.7	6.0	-	(74.8)	-	-
Other	-	-	-	19.7	-	(19.7)	-	-
	1,052.5	705.3	68.1	491.6	-	(2,317.5)	-	-
Revenues	$1,217.4	$ 962.6	$160.3	$ 5,059.2	$(28.4)	$ (2,317.3)	$ 6.7	$ 5,060.5
Operating margin	$213.0	$ 121.8	$85.9	$ 82.8	$(28.4)	$ 0.1	$ 6.7	$ 481.9
Other financial information:								
Total assets	$1,647.3	$ 425.2	$713.2	$ 702.3	$56.0	$ 78.0	$ 168.4	$ 3,790.4
Capital expenditures (1)	$112.0	$ 9.8	$252.6	$ 1.5	$-	$ 1.4	$ 1.8	$ 379.1

(1) Logistics Assets segment capital expenditures includes petroleum logistics acquisitions. See Note 4.

Nine Months Ended September 30, 2010

	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$144.7	$ 340.2	$-	$ 3,323.1	$7.0	$ (0.1)	$ 0.7	$ 3,815.6
Fees from midstream services	17.7	9.2	60.1	32.9	-	-	-	119.9
Other	(1.9)	0.6	(0.4)	11.5	-	-	3.0	12.8
	160.5	350.0	59.7	3,367.5	7.0	(0.1)	3.7	3,948.3
Intersegment revenues								
	792.6	565.2	0.5	379.6	-	(1,737.9)	-	-

Sales of commodities								
Fees from midstream services	0.8	2.0	61.3	0.7	-	(64.8)	-	-
Other	-	-	-	16.3	-	(16.3)	-	-
	793.4	567.2	61.8	396.6	-	(1,819.0)	-	-
Revenues	$953.9	$ 917.2	$121.5	$ 3,764.1	$7.0	$ (1,819.1)	$ 3.7	$ 3,948.3
Operating margin	$176.8	$ 74.9	$52.9	$ 48.8	$7.0	$ -	$ 3.6	$ 364.0
Other financial information:								
Total assets	$1,627.7	$ 448.5	$432.7	$ 426.4	$65.4	$ 62.3	$ 397.0	$ 3,460.0
Capital expenditures	$41.0	$ 6.2	$33.1	$ 1.8	$-	$ -	$ 1.7	$ 83.8

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Sales of commodities				
Natural gas sales	$304.6	$261.7	$846.2	$832.8
NGL sales	1,323.4	880.4	3,969.1	2,901.1
Condensate sales	25.7	22.4	80.3	73.6
Derivative activities	(10.0)	7.7	(25.4)	8.1
Fees from midstream services				
Fractionating and treating fees	25.7	12.4	60.1	40.7
Storage and terminaling fees	11.7	11.4	38.9	30.2
Transportation fees	16.2	10.3	38.4	25.6
Gas processing fees	8.3	8.3	23.1	23.4
Other				
Business interruption insurance	-	1.3	3.0	3.0
Other	8.0	4.1	26.8	9.8
	$1,713.6	$1,220.0	$5,060.5	$3,948.3

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Reconciliation of operating margin to net income				
Operating margin	$151.6	$120.1	$481.9	$364.0
Depreciation and amortization expense	(45.7)	(50.2)	(134.3)	(136.9)
General and administrative expense	(35.4)	(27.0)	(105.1)	(81.0)
Interest expense, net	(26.8)	(30.0)	(83.3)	(83.9)
Income tax expense	(7.4)	(8.6)	(18.5)	(18.5)
Other, net	0.2	(8.6)	(0.1)	(4.7)
Net income (loss)	$36.5	$(4.3)	$140.6	$39.0

Note 16 — Stock and Other Compensation Plans

For a discussion of our stock compensation plans, see Note 24 of the Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K.

2010 TRC Stock Incentive Plan

Restricted Stock to Executive Management

For the three and nine months ended September 30, 2011, the total compensation expenses associated with the restricted stock awards granted to our executive management and certain employees in December 2010 (1,350,000 shares), February 2011 (33,140 shares) and August 2011 (51,080 shares) were $3.4 million and $10.0 million. There were no shares forfeited or vested under this plan during the three and nine months ended September 30, 2011.

Director Grants

In February 2011, our Compensation Committee (the “Committee”) also made equity–based awards of 24,250 shares to our non-management directors under this incentive plan. The awards vested upon the grant date. The total compensation expense for the awards was $0.8 million for the nine months ended September 30, 2011.

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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

Financial Presentation

Targa Resources Corp. is a publicly traded Delaware corporation formed in October 2005. Our common shares are listed on the New York Stock Exchange ("NYSE") under the symbol "TRGP." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," "the Company," or "Targa" are intended to mean our consolidated busin and operations, including our wholly-owned subsidiary TRI Resources Inc. ("TRI").

We own general and limited partner interests, including Incentive Distribution Rights ("IDRs"), in Targa Resources Partners LP ("the Partnership"), a publicly traded Delaware limited partnership that is a leading provider of midstream natural gas and natural gas liquid services in the United States. Common units of the Partnership are listed on the NYSE under the symbol "NGLS." The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas, storing, fractionating, treating, transporting and selling natural gas liquids, or NGLs, and NGL products and storing and terminaling refined petroleum products and crude oil.

Our primary business objective is to increase our cash available for dividends to our stockholders by assisting the Partnership in executing its business strategy. We may facilitate the Partnership's growth through various forms of financial support, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership, if needed, to support its ability to make distributions. We also may enter into other economic transactions intended to increase our ability to make cash available for dividends over time. In addition, we may acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

An indirect subsidiary of ours is the sole member of Targa Resources GP LLC (the "General Partner"), which is the general partner of the Partnership. Because we control the General Partner, under generally accepted accounting principles, we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, our financial results are combined with the Partnership's financial results in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our results of operations as net income attributable to non-controlling interests. Therefore, throughout this discussion, we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent including our non-Partnership subsidiaries.

Operations

The Partnership is 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.

The Partnership reports its 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 the Partnership's hedging activities are reported in Other.

The Partnership's Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing such 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.

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The Partnership's Logistics and Marketing division is also referred to as the Downstream Business. The Downstream Business includes all the activities necessary to convert raw NGLs 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 the Partnership's other operations.

The Partnership's 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, the Partnership's 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 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities. See "2011 Developments".

The Partnership's Marketing and Distribution segment covers activities required to distribute and market raw and finished natural gas liquids and all natural gas marketing activities. It includes: (1) marketing the Partnership's NGL production and purchasing NGL 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 the Partnership from the Partnership's Natural Gas Gathering and Processing division and the purchase and resale of natural gas in selected United States markets.

Other contains the results of the Partnership's commodity hedging activities.

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions.

The Partnership files its own separate quarterly reports. The results of operations included in our consolidated financial statements will differ from the results of operations of the Partnership primarily due to the financial effects of: non-controlling interests in the Partnership, our separate debt obligations, certain general and administrative costs applicable to us as a separate public company and certain non-operating assets and liabilities that we retained and were not included in the asset conveyances to the Partnership.

2011 Developments

On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units representing limited partner interests in the Partnership ("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, the Partnership issued an additional 1,200,000 common units, providing net proceeds of $38.8 million. In addition, we contributed $6.3 million to the Partnership for 187,755 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

On February 2, 2011, the Partnership closed a private placement of $325.0 million in aggregate principal amount of 6 % Senior Notes due 2021 (the "6 % Notes"). The net proceeds of this offering were $318.8 million after deducting expenses of the offering. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

On February 4, 2011, the Partnership exchanged an additional $158.6 million principal amount of its 6 % Notes plus payments of $28.6 million, including $0.9 million of accrued interest, for $158.6 million aggregate principal amount of its 11¼% Senior Notes due 2017 (the “11¼% Notes”). The debt covenants related to the remaining $72.7 million of face value of the 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.

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On March 15, 2011, the Partnership acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel (the "Channelview Terminal") for $29.0 million. The Channelview Terminal, with storage capacity of 544,000 barrels, can handle multiple grades of blend stocks, petroleum products and crude and has potential for expansion, as well as integration with the Partnership’s other logistics operations.

On April 26, 2011, certain of our stockholders sold, in a secondary public offering, 5,650,000 shares of our common stock under a registration statement on Form S-1 at a price of $31.73 per share of common stock ($30.65 per share, net of underwriting discounts), providing net proceeds of $173.2 million to selling stockholders. We received no proceeds from the sale of shares by the selling stockholders. Pursuant to the exercise of the underwriters’ overallotment option, selling stockholders also sold an additional 847,500 shares of our common stock, providing additional net proceeds of $26.0 million. We incurred approximately $0.6 million of expenses in connection with the offering, including all expenses of the selling stockholders which we have paid.

On May 9, 2011, the Partnership announced a 100,000 barrel per day expansion of its majority owned Cedar Bayou Fractionator (“CBF”) at Mont Belvieu, Texas. Substantially all of the capacity of this expansion is currently contracted with long-term, use-or-pay, firm capacity fractionating agreements. The 100,000 barrel per day expansion will be fully integrated with the Partnership’s 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 the Partnership’s LPG export terminal at Galena Park, Texas on the Houston Ship Channel. We estimate that the total capital expenditures for the CBF expansion and the Partnership's related infrastructure enhancements at Mont Belvieu will be approximately $360 million and construction will be completed in the first quarter of 2013.

On September 19, 2011, the Partnership announced a $250 million expansion of its Mont Belvieu complex and its existing import/export marine terminal at Galena Park to provide export capability for more than 5,000 barrels per hour (Bbl/hr) of fully refrigerated, low ethane propane. The expansion project, expected to be operational in the third quarter of 2013, will allow the Partnership to load three to four VLGC (very large gas carrier) class ships per month and is in addition to its existing capabilities to handle multiple MGC (medium gas carrier) export cargos of HD-5 grade propane, imports/exports of LPGs and petrochemicals and other spot ship and barge business.

On September 30, 2011 the Partnership acquired two refined petroleum products and crude oil storage and terminaling facilities. The facility on the Hylebos Waterway in the Port of Tacoma, Washington (the “Tacoma Terminal”) has 758,000 barrels of capacity and handles refined petroleum products, LPGs and biofuels, including ethanol and biodiesel. The facility on the Patapsco River in Baltimore, Maryland (the “Baltimore Terminal”) has approximately 505,000 barrels of storage capacity. Both terminals contain blending and heating capabilities, and have tanker truck and barge loading and unloading infrastructure. Total consideration for both facilities was $127.7 million plus an additional $7.5 million for estimated working capital.

On October 19, 2011, the Partnership announced a new 200 MMcf/d cryogenic processing plant for the Partnership’s North Texas System to meet increasing production, continued producer activity and expected volumes from significant new acreage dedications in the liquids-rich, oily areas of the Barnett Shale. The new processing plant, which will be located in Wise County, Texas, is expected to be operational in mid-2013, subject to regulatory approvals, and is expected to require a capital investment related to the plant and associated projects that are currently estimated at approximately $150 million.

2011 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.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment. The amendment, which becomes effective during interim and annual periods beginning after December 15, 2011, allows entities to first assess qualitative factors when testing goodwill for impairment. Early adoption is permitted.

How We Evaluate Our Operations

Our consolidated operations include the operations of the Partnership due to our ownership and control of the General Partner. We have no separate, direct operating activities from those conducted by the Partnership. Our financial results differ from the Partnership's due to the financial effects of: non-controlling interests in the Partnership, our separate debt obligations, certain non-operating costs associated with assets and liabilities that we retained and were not included in asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company.

Distributable Cash Flow. We define distributable cash flow as distributions due to us from the Partnership, less our specific general and administrative costs as a separate public reporting entity, the interest carry costs associated with our debt and taxes attributable to our earnings. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts, and others to compare basic cash flows generated by us to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash dividends. Distributable cash flow is also an important financial measure for our shareholders 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 dividend rates. Distributable cash flow is also a quantitative standard used throughout the investment community because the share value is generally determined by the share's yield (which in turn is based on the amount of cash dividends the entity pays to a shareholder).

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The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to pay dividends to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors 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 compatible 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 process. On October 11, 2011, the Partnership announced that the board of directors of its General Partner declared a quarterly distribution for the three months ended September 30, 2011 of $0.5825 per common unit, or an annual rate of $2.33 per common unit. Based on these distribution rates, we will receive quarterly distributions of $6.8 million, or $27.1 million on an annualized basis, in respect of our common units in the Partnership, and based on these distribution rates, we will receive quarterly distributions of $8.8 million and $1.2 million, or $35.3 million and $4.8 million on an annualized basis, based on our IDRs and 2% general partner interests. See Note 7 – Partnership Units and Related Matters.

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
	(in millions)	
Targa Resources Corp Distributable Cash Flow		
Distributions declared by Targa Resources Partners LP associated with:		
General Partner Interests	$1.2	$3.5
Incentive Distribution Rights	8.8	23.4
Common Units	6.8	19.9
Total distributions declared by Targa Resources Partners LP	16.8	46.8
Income (expenses) of TRC Non-Partnership		
General and administrative expenses	(1.7)	(6.5)
Interest expense, net	(1.1)	(2.9)
Plus: Current tax benefit for TRC Non-Partnership (1)	6.1	0.6
Taxes funded with cash on hand (2)	-	5.1
Other income	0.1	3.0
Distributable cash flow	$20.2	$46.1

(1) Excludes $1.2 million and $3.6 million of non-cash current tax expense arising from amortization of deferred long term tax assets from drop down gains realized for tax purposes and paid in 2010 for the three and nine months ended September 30, 2011. Includes a one-time benefit in current tax expense attributable primarily to overpayment of prior year income taxes.

(2) Current period portion of amount established at our IPO to fund taxes related to deferred tax gains.

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	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
	(in millions)	
Reconciliation of net income attributable to Targa Resources Corp. to Distributable Cash Flow		
Net income of Targa Resources Corp.	$36.5	$140.6
Less: Net income of Targa Resources Partners LP	(44.9)	(158.6)
Net loss for TRC Non-Partnership	(8.4)	(18.0)
Plus: TRC Non-Partnership income tax expense	5.9	13.3
Plus: Distributions declared by the Partnership	16.8	46.8
Plus: Non-cash gain on hedges	(0.9)	(3.8)
Plus: Depreciation - Non-Partnership assets	0.7	2.1
Plus: Current tax benefit for TRC Non-Partnership (1)	6.1	0.6
Plus: Taxes funded with cash on hand (2)	-	5.1
Distributable cash flow	$20.2	$46.1

(1) Excludes $1.2 million and $3.6 million of non-cash current tax expense arising from amortization of deferred long term tax assets from drop down gains realized for tax purposes and paid in 2010 for the three and nine months ended September 30, 2011. Includes a one-time benefit in current tax expense attributable primarily to overpayment of prior year income taxes.

(2) Current period portion of amount established at our IPO to fund taxes related to deferred tax gains.

How We Evaluate the Partnership's Operations

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

Management uses a variety of financial measures and operational measurements to analyze the Partnership's 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. The Partnership's profitability is impacted by its 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 its 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, the Partnership's profitability is impacted by its ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to its Downstream Business' fractionation facilities. The Partnership fractionates NGLs generated by its gathering and processing plants, as well as by contracting for mixed NGL supply from third-party gathering or fractionation facilities.

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

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As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks 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 its logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership's 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 the Partnership's operating expenses. These expenses, other than fuel and power, generally remain relatively stable and independent of the volumes through its systems but fluctuate depending on the scope of the activities performed during a specific period.

Gross Margin. We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as the Partnership's 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, less product purchases, which consists primarily of NGL purchases. 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 the Partnership's 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.

Our 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 the Partnership's assets without regard to financing methods, capital structure or historical cost basis;

- the Partnership's 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.

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Adjusted EBITDA. The Partnership defines 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 the Partnership and by external users of our financial statements such as investors, commercial banks and others.

The economic substance behind the Partnership’s use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and make distributions to its 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. Investors 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.

The Partnership 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. The Partnership defines 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 non-cash 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 the Partnership and by external users of the Partnership’s financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership’s unitholders. Using this metric, the Partnership’s management and external users of its financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important financial measure for the Partnership’s unitholders since it serves as an indicator of the Partnership’s success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership’s 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. Investors 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 the Partnership’s industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The Partnership 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.

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Non-GAAP Financial Measures

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$227.2	$184.8	$689.3	$550.6
Operating expenses	(76.5)	(66.0)	(214.1)	(190.2)
Operating margin	150.7	118.8	475.2	360.4
Depreciation and amortization expenses	(45.0)	(43.3)	(132.2)	(128.3)
General and administrative expenses	(33.7)	(26.7)	(98.6)	(80.0)
Interest expense, net	(25.7)	(27.9)	(80.4)	(86.6)
Income tax expense	(1.5)	(1.7)	(5.2)	(3.9)
Gain (loss) on sale of assets	0.3	-	0.4	-
Other, net (1)	(0.2)	(0.8)	(0.6)	29.8
Targa Resources Partners LP Net income	$44.9	$18.4	$158.6	$91.4

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by (used in) operating activities	$(61.3)	$60.3	$191.3	$238.9
Net income attributable to noncontrolling interests	(9.0)	(4.6)	(29.6)	(18.2)
Interest expense, net (1)	24.7	22.2	73.7	52.8
Current income tax expense	2.4	1.8	4.6	3.6
Other (2)	18.8	(7.6)	10.8	(7.3)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	105.4	24.5	169.8	(40.3)
Accounts payable and other liabilities	26.3	(6.1)	(76.0)	52.5
Targa Resources Partners LP Adjusted EBITDA	$107.3	$90.5	$344.6	$282.0

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of: $1.0 million and $6.7 million for the three and nine months ended September 30, 2011; and $1.8 million and $4.4 million for the three and nine months ended September 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.

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	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 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	$35.9	$13.8	$129.0	$73.2
Add:				
Interest expense, net (1)	25.7	27.9	80.4	86.6
Income tax expense	1.5	1.7	5.2	3.9
Depreciation and amortization expenses	45.0	43.3	132.2	128.3
Risk management activities	2.0	6.1	6.0	(2.9)
Noncontrolling interests adjustment	(2.8)	(2.3)	(8.2)	(7.1)
Targa Resources Partners LP Adjusted EBITDA	$107.3	$90.5	$344.6	$282.0

(1) Includes affiliate and allocated interest expense.

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 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	$35.9	$13.8	$129.0	$73.2
Affiliate and allocated interest expense	-	3.9	-	29.4
Depreciation and amortization expenses	45.0	43.3	132.2	128.3
Deferred income tax expense	(0.9)	(0.1)	0.6	0.3
Amortization in interest expense	2.5	2.4	8.1	5.1
Risk management activities	2.0	6.1	6.0	(2.9)
Maintenance capital expenditures	(24.7)	(12.7)	(57.2)	(29.7)
Other (1)	5.6	(0.3)	10.8	(2.9)
Distributable cash flow	$65.4	$56.4	$229.5	$200.8

(1) Includes reimbursements of certain environmental maintenance capital expenditures by us 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 nine months ended September 30, 2011.

Financial Information – Partnership versus Non-Partnership

As a supplement to the financial statements included in this 10-Q, we present the following tables which segregate our consolidated balance sheet, statement of operations and statement of cash flows between Partnership and Non-Partnership activities. Partnership results are presented on a common control accounting basis – the same basis reported in the Partnership's Quarterly Report on Form 10-Q (the "Partnership Form 10-Q"). Except when otherwise noted, the remainder of this management's discussion and analysis refers to these disaggregated results.

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Results of Operations – Partnership versus Non-Partnership

	Three Months Ended September 30, 2011			Three Months Ended September 30, 2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues (1)	$1,713.6	$1,712.7	$ 0.9	$1,220.0	$1,218.4	$ 1.6
Costs and Expenses:						
Product purchases	1,485.5	1,485.5	-	1,033.7	1,033.6	0.1
Operating expenses	76.5	76.5	-	66.2	66.0	0.2
Depreciation and amortization (2)	45.7	45.0	0.7	50.2	43.3	6.9
General and administrative (3)	35.4	33.7	1.7	27.0	26.7	0.3
Other	(0.3)	(0.3)	-	(0.4)	-	(0.4)
	1,642.8	1,640.4	2.4	1,176.7	1,169.6	7.1
Income from operations	70.8	72.3	(1.5)	43.3	48.8	(5.5)
Other income (expense):						
Interest expense, net - third party (4)	(26.8)	(25.7)	(1.1)	(30.0)	(24.0)	(6.0)
Interest expense - intercompany (5)	-	-	-	-	(3.9)	3.9
Equity in earnings of unconsolidated investment	2.2	2.2	-	1.1	1.1	-
Loss on early debt extinguishment (4)	-	-	-	(10.6)	-	(10.6)
Gain (loss) on mark-to-market derivative instruments	(1.8)	(1.8)	-	(0.1)	(1.9)	1.8
Other income (expense)	(0.5)	(0.6)	0.1	0.6	-	0.6
Income before income taxes	43.9	46.4	(2.5)	4.3	20.1	(15.8)
Income tax expense	(7.4)	(1.5)	(5.9)	(8.6)	(1.7)	(6.9)
Net income (loss)	36.5	44.9	(8.4)	(4.3)	18.4	(22.7)
Less: Net income attributable to noncontrolling interests (6)	31.6	9.0	22.6	13.2	4.6	8.6
Net income (loss) after noncontrolling interests	$4.9	$35.9	$ (31.0)	$(17.5)	$13.8	$ (31.3)

The major Non-Partnership results of operations relate to:

(1) Business interruption revenue ($1.3 million in 2010) and amortization of Other Comprehensive Income ("OCI") related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges

(2) Depreciation on assets excluded from drop down transactions and corporate administrative assets

(3) General and administrative expenses retained by TRC, related to its status as a public entity

(4) Interest expense and other gains and losses related to TRC and TRI debt obligations

(5) Interest on pre-drop down intercompany debt obligations

(6) TRC non-controlling interest in the Partnership

	Nine Months Ended September 30, 2011			Nine Months Ended September 30, 2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues (1)	$5,060.5	$5,053.8	$ 6.7	$3,948.3	$3,944.6	$ 3.7
Costs and Expenses:						
Product purchases	4,364.5	4,364.5	-	3,393.9	3,394.0	(0.1)
Operating expenses	214.1	214.1	-	190.4	190.2	0.2
Depreciation and amortization (2)	134.3	132.2	2.1	136.9	128.3	8.6
General and administrative (3)	105.1	98.6	6.5	81.0	80.0	1.0
Other	(0.3)	(0.4)	0.1	(0.4)	-	(0.4)
	4,817.7	4,809.0	8.7	3,801.8	3,792.5	9.3
Income from operations	242.8	244.8	(2.0)	146.5	152.1	(5.6)
Other income (expense):						
Interest expense, net - third party (4)	(83.3)	(80.4)	(2.9)	(83.9)	(57.2)	(26.7)
Interest expense - intercompany (5)	-	-	-	-	(29.4)	29.4
Equity in earnings of unconsolidated investment	5.2	5.2	-	3.8	3.8	-
Loss on debt repurchases (4)	-	-	-	(17.4)	-	(17.4)
Gain on early debt extinguishment (4)	-	-	-	8.1	-	8.1
Gain (loss) on mark-to-market derivative instruments	(5.0)	(5.0)	-	(0.4)	26.0	(26.4)
Other income (expense)	(0.6)	(0.8)	0.2	0.8	-	0.8
Income before income taxes	159.1	163.8	(4.7)	57.5	95.3	(37.8)
Income tax expense	(18.5)	(5.2)	(13.3)	(18.5)	(3.9)	(14.6)
Net income (loss)	140.6	158.6	(18.0)	39.0	91.4	(52.4)
Less: Net income attributable to noncontrolling interests (6)	118.4	29.6	88.8	46.2	18.2	28.0
Net income (loss) after noncontrolling interests	$22.2	$129.0	$ (106.8)	$(7.2)	$73.2	$ (80.4)

The major Non-Partnership results of operations relate to:

(1) Business interruption revenue ($3.0 million in 2011 and $3.0 million in 2010) and amortization of OCI related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges

(2) Depreciation on assets excluded from drop down transactions and corporate administrative assets

(3) General and administrative expenses retained by TRC, related to its status as a public entity

(4) Interest expense and other gains and losses related to TRC and TRI debt obligations

(5) Interest on pre-drop down intercompany debt obligations

(6) TRC non-controlling interest in the Partnership

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Balance Sheets – Partnership versus Non-Partnership

The following table breaks down the consolidated balance sheets as of September 30, 2011 and December 31, 2010 into Partnership and our standalone ("TRC Non-Partnership") financial results. Partnership results are presented on a common control accounting basis – the same basis reported in the Partnership Form 10-Q.

	September 30, 2011			December 31, 2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
ASSETS						
Current assets:						
Cash and cash equivalents (1)	$154.1	$68.9	$ 85.2	$188.4	$76.3	$ 112.1
Trade receivables, net	544.5	544.5	-	466.6	466.1	0.5
Inventory	139.4	139.3	0.1	50.4	50.3	0.1
Deferred income taxes (2)	-	-	-	3.6	-	3.6
Assets from risk management activities	35.2	35.2	-	25.2	25.2	-
Other current assets (1)	17.5	8.4	9.1	16.3	2.9	13.4
Total current assets	890.7	796.3	94.4	750.5	620.8	129.7
Property, plant and equipment, at cost (1)	3,572.2	3,538.5	33.7	3,331.4	3,299.5	31.9
Accumulated depreciation	(955.4)	(935.2)	(20.2)	(822.4)	(804.3)	(18.1)
Property, plant and equipment, net	2,616.8	2,603.3	13.5	2,509.0	2,495.2	13.8
Long-term assets from risk management activities	20.8	20.8	-	18.9	18.9	-
Other long-term assets (3)	262.1	201.6	60.5	115.4	51.5	63.9
Total assets	$3,790.4	$3,622.0	$ 168.4	$3,393.8	$3,186.4	$ 207.4
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (4)	$638.6	$594.1	$ 44.5	$590.0	$524.2	$ 65.8
Affiliate payable (receivable) (5)	-	60.2	(60.2)	-	51.4	(51.4)
Deferred income taxes	0.2	-	0.2	-	-	-
Liabilities from risk management activities	34.7	34.7	-	34.2	34.2	-
Total current liabilities	673.5	689.0	(15.5)	624.2	609.8	14.4
Long-term debt (6)	1,603.4	1,514.1	89.3	1,534.7	1,445.4	89.3
Long-term liabilities from risk management activities	10.7	10.7	-	32.8	32.8	-
Deferred income taxes (2)	117.6	9.3	108.3	111.6	8.7	102.9
Other long-term liabilities (7)	52.7	43.9	8.8	54.4	40.6	13.8
Total liabilities	2,457.9	2,267.0	190.9	2,357.7	2,137.3	220.4

Total owners' equity	1,332.5	1,355.0	(22.5)	1,036.1	1,049.1	(13.0)
Total liabilities and owners' equity	$3,790.4	$3,622.0	$ 168.4	$3,393.8	$3,186.4	$ 207.4

The major Non-Partnership balance sheet items relate to:

(1) Parent operating assets consisting of cash, administrative property and equipment, and prepaid insurance
(2) Current and long-term deferred income tax balances
(3) Long-term tax assets stemming from 2010 drop down transactions
(4) Accrued current employee liabilities related to payroll and incentive compensation plans and taxes payable.
(5) Intercompany receivable with the Partnership related to the ongoing execution of the Omnibus Agreement
(6) Long-term debt obligations of TRC and TRI
(7) Long-term liabilities related to incentive compensation plans and deferred rent related to the headquarters office lease

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Statements of Cash Flows – Partnership versus Non-Partnership

The following table breaks down the consolidated statements of cash flows for the nine months ended September 30, 2011 and 2010 into Partnership and TRC Non-Partnership financial results. Partnership results are presented on a common control accounting basis – the same basis reported in the Partnership Form 10-Q.

	Nine Months Ended September 30,					
	2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Cash flows from operating activities			(In millions)			
Net income (loss)	$140.6	$158.6	$ (18.0)	$39.0	$91.4	$ (52.4)
Adjustments to reconcile net income to net cash provided by operating activities:						
Amortization in interest expense	7.2	6.7	0.5	6.2	4.4	1.8
Paid-in-kind interest expense	-	-	-	9.0	-	9.0
Compensation on equity grants	11.4	1.2	10.2	0.5	0.3	0.2
Interest expense on affiliate and allocated indebtedness (1)	-	-	-	-	29.4	(29.4)
Depreciation and amortization expense (4)	134.3	132.2	2.1	136.9	128.3	8.6
Accretion of asset retirement obligations	2.7	2.7	-	2.4	2.4	-
Deferred income tax expense	10.9	0.6	10.3	17.6	0.3	17.3
Equity in earnings (losses) of unconsolidated investment, net of distributions	(1.4)	(1.4)	-	-	-	-
Risk management activities (2)	(18.8)	(15.1)	(3.7)	(16.5)	(5.4)	(11.1)
Loss on sale of assets	(0.4)	(0.4)	-	(0.4)	-	(0.4)
Gain on debt repurchases	-	-	-	17.4	-	17.4
Loss on early debt extinguishment	-	-	-	(8.1)	-	(8.1)
Changes in operating assets and liabilities: (3)	(121.9)	(93.8)	(28.1)	(78.0)	(12.2)	(65.8)
Net cash provided by (used in) operating activities	164.6	191.3	(26.7)	126.0	238.9	(112.9)
Cash flows from investing activities						
Outlays for property, plant and equipment (4)	(214.3)	(211.4)	(2.9)	(84.2)	(82.5)	(1.7)
Business acquisitions	(164.2)	(164.2)	-	-	-	-
Investment in unconsolidated affiliate	(11.9)	(11.9)	-	-	-	-
	-	-	-	1.1	1.1	-

Return of capital from unconsolidated affiliate						
Other	0.3	0.3	-	2.4	2.1	0.3
Net cash used in investing activities	(390.1)	(387.2)	(2.9)	(80.7)	(79.3)	(1.4)
Cash flows from financing activities						
Loan Facilities of the Partnership:						
Borrowings	1,751.0	1,751.0	-	1,428.1	1,428.1	-
Repayments	(1,684.0)	(1,684.0)	-	(904.0)	(904.0)	-
Repayment of affiliated indebtedness (1)	-	-	-	-	(740.2)	740.2
Loan Facilities- Non-Partnership:						
Borrowings (5)	-	-	-	495.0	-	495.0
Repayments (5)	-	-	-	(949.5)	-	(949.5)
Proceeds from sale of Partnership interests	-	-	-	224.7	-	224.7
Partnership equity transactions (6)	298.0	304.3	(6.3)	317.8	317.8	-
Distributions to noncontrolling interests (7)	(142.0)	(185.7)	43.7	(101.2)	(135.2)	34.0
Intercompany capital contributions (distributions)	-	9.1	(9.1)	-	(95.7)	95.7
Distributions under common control	-	-	-	-	(46.6)	46.6
Repurchases of common stock	-	-	-	(0.1)	-	(0.1)
Stock options exercised	-	-	-	0.9	-	0.9
Dividends to common and common equivalent shareholders (8)	(25.6)	-	(25.6)	(200.0)	-	(200.0)
Dividends to preferred shareholders (8)	-	-	-	(219.9)	-	(219.9)
Costs incurred in connection with financing arrangements (5)	(6.2)	(6.2)	-	(39.5)	(20.2)	(19.3)
Net cash provided by (used in) financing activities	191.2	188.5	2.7	52.3	(196.0)	248.3
Net change in cash and cash equivalents	(34.3)	(7.4)	(26.9)	97.6	(36.4)	134.0
Cash and cash equivalents, beginning of period	188.4	76.3	112.1	252.4	90.9	161.5
Cash and cash equivalents, end of period	$154.1	$68.9	$ 85.2	$350.0	$54.5	$ 295.5

The major Non-Partnership cash flow items relate to:

(1) Affiliated indebtedness that was settled in drop down transactions

(2) Amortization of OCI related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges

(3)

See Balance Sheet – Partnership versus Non-Partnership for a description of the Non-Partnership operating assets and liabilities

(4) Cash and non-cash activity related to corporate administrative assets

(5) Cash activity related to TRC and TRI debt obligations

(6) Contribution to the Partnership to maintain our 2% general partner interest

(7) Cash distributions received by TRC for its general partners and limited partner interests and IDRs in the Partnership

(8) TRC dividends paid to common and preferred shareholders

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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 nine months ended September 30, 2011 and 2010 (in millions, except operating and price amounts):

	Three Months Ended September 30,		Variance 2011 vs. 2010		Nine Months Ended September 30,		Variance 2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
Revenues	$1,713.6	$1,220.0	$493.6	40%	$5,060.5	$3,948.3	$1,112.2	28%
Product purchases	1,485.5	1,033.7	451.8	44%	4,364.5	3,393.9	970.6	29%
Gross margin (1)	228.1	186.3	41.8	22%	696.0	554.4	141.6	26%
Operating expenses	76.5	66.2	10.3	16%	214.1	190.4	23.7	12%
Operating margin (2)	151.6	120.1	31.5	26%	481.9	364.0	117.9	32%
Depreciation and amortization expenses	45.7	50.2	(4.5)	(9%)	134.3	136.9	(2.6)	(2%)
General and administrative expenses	35.4	27.0	8.4	31%	105.1	81.0	24.1	30%
Other	(0.3)	(0.4)	0.1	(25%)	(0.3)	(0.4)	0.1	(25%)
Income from operations	70.8	43.3	27.5	64%	242.8	146.5	96.3	66%
Interest expense, net	(26.8)	(30.0)	3.2	(11%)	(83.3)	(83.9)	0.6	(1%)
Equity in earnings of unconsolidated investment	2.2	1.1	1.1	100%	5.2	3.8	1.4	37%
Loss on debt repurchases	-	-	-	0%	-	(17.4)	17.4	(100%)
Gain (loss) on early debt extinguishment, net	-	(10.6)	10.6	(100%)	-	8.1	(8.1)	(100%)
Loss on mark-to-market derivative instruments	(1.8)	(0.1)	(1.7)	1,700%	(5.0)	(0.4)	(4.6)	1,150%
Other	(0.5)	0.6	(1.1)	(183%)	(0.6)	0.8	(1.4)	(175%)
Income tax expense	(7.4)	(8.6)	1.2	(14%)	(18.5)	(18.5)	-	0%
Net income (loss)	36.5	(4.3)	40.8	(949%)	140.6	39.0	101.6	261%
Less: Net income attributable to noncontrolling interests	31.6	13.2	18.4	139%	118.4	46.2	72.2	156%
Net income (loss) attributable to Targa Resources Corp.	4.9	(17.5)	22.4	(128%)	22.2	(7.2)	29.4	(408%)
Less:								
Dividends on Series B preferred stock	-	(1.4)	1.4	(100%)	-	(8.4)	8.4	(100%)
	-	-	-	0%	-	(177.8)	177.8	(100%)

Dividends to common equivalents								
Net income (loss) available to common shareholders	$4.9	$(18.9)	$23.8	(126%)	$22.2	$(193.4)	$215.6	(111%)
Operating statistics:								
Plant natural gas inlet, MMcf/d (3) (4)	2,087.0	2,216.4	(129.4)	(6%)	2,152.8	2,296.5	(143.7)	(6%)
Gross NGL production, MBbl/d	121.4	121.6	(0.2)	(0%)	122.2	120.8	1.4	1%
Natural gas sales, BBtu/d (4)	799.7	673.1	126.6	19%	746.6	679.3	67.3	10%
NGL sales, MBbl/d	258.9	244.2	14.7	6%	265.1	246.0	19.1	8%
Condensate sales, MBbl/d	3.2	3.4	(0.2)	(6%)	3.2	3.6	(0.4)	(11%)

(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 the Partnership’s Operations.”

(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 the Partnership’s Operations.”

(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(4) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

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

Consolidated revenues (including the impacts of hedging) increased due to higher net impact of realized prices on NGLs and condensate ($378.2 million), higher NGL and natural gas sales volumes ($103.8 million) and higher fee-based and other revenues ($22.3 million) partially offset by lower realized prices on natural gas ($9.5 million) and lower condensate sales volumes ($1.1 million).

Consolidated operating margin increased $31.5 million, reflecting higher gross margin and higher revenues ($493.6 million) partially offset by increases in product purchase costs ($451.8 million). The increase in consolidated operating expenses of $10.3 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.

Depreciation and amortization expenses decreased $4.5 million primarily due to assets that were spun-off ($6.0 million), fully depreciated assets ($2.2 million), offset by new projects ($3.7 million).

General and administrative expenses increased $8.4 million reflecting increased compensation and benefits.

Consolidated interest expense decreased $3.2 million due to higher interest expense on third party debt incurred by the Partnership ($1.7 million) offset by lower interest expense ($4.9 million) associated with our outstanding borrowings. Our borrowings decreased due to the repayment to us of affiliate debt by the Partnership and our subsequent re-purchases of Holdco debt and payments to extinguish the outstanding balance of our revolver.

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

Loss on mark-to-market derivative instruments increased $1.7 million attributable to interest rate swaps that the Partnership terminated on September 6, 2011.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Consolidated revenues (including the impacts of hedging) increased due to the net impact of higher realized prices on NGLs and condensate ($832.9), higher NGL and natural gas sales volumes ($309.6 million) and higher fee-based and other revenues ($59.1 million), partially offset by lower realized prices on natural gas ($80.3 million) and lower condensate sales volumes ($9.1 million).

Consolidated operating margin increased $117.9 million, reflecting higher gross margin and higher revenues ($1,112.2 million) partially offset by increases in product purchase costs ($970.6 million). The increase in consolidated operating expenses of $23.7 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.

Depreciation and amortization expenses decreased $2.6 million primarily due to assets that were spun-off ($6.2 million), fully depreciated assets ($5.4 million), offset by new projects ($8.8 million).

General and administrative expenses increased $24.1 million reflecting increased compensation and benefits.

Consolidated interest expense decreased $0.6 million due to higher interest expense on third party debt incurred by the Partnership ($23.2 million) offset by lower interest expense ($23.8 million) associated with our outstanding borrowings. Our borrowings decreased due to the repayment to us of affiliate debt by the Partnership and our subsequent re-purchases of Holdco debt and payments to extinguish the outstanding balance of our revolver.

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

Results of Operations—By Segment

We have segregated the following segment operating margins between Partnership and TRC Non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions between Targa and the Partnership as if they occurred in prior periods. TRC Non-Partnership segment results include certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected as such under GAAP in the Partnership common control results.

	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated Operating Margin
Three Months Ended				(In millions)				
September 30, 2011	$71.8	$ 39.8	$30.1	$ 19.7	$(10.8)	$ 0.1	$ 0.9	$ 151.6
September 30, 2010	49.6	23.5	23.6	15.0	7.1	-	1.3	120.1
Nine Months Ended								
September 30, 2011	$213.0	$ 121.8	$85.9	$ 82.8	$(28.4)	$ 0.1	$ 6.7	$ 481.9
September 30, 2010	176.8	74.9	52.9	48.8	7.0	-	3.6	364.0

A discussion of the Partnership segments results follows:

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Results of Operations of the Partnership – By Segment

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended September 30,		2011 vs. 2010		Nine Months Ended September 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
	($ in millions)							
Gross margin	$ 102.4	$ 77.4	$ 25.0	32%	$ 299.3	$ 250.4	$ 48.9	20%
Operating expenses	30.6	27.8	2.8	10%	86.3	73.6	12.7	17%
Operating margin	$ 71.8	$ 49.6	$ 22.2	45%	$ 213.0	$ 176.8	$ 36.2	20%
Operating statistics:								
Plant natural gas inlet, MMcf/d (1),(2)	628.2	583.7	44.5	8%	604.4	582.0	22.4	4%
Gross NGL production, MBbl/d	75.1	70.6	4.5	6%	73.1	70.2	2.9	4%
Natural gas sales, BBtu/d (2),(3)	295.8	254.5	41.3	16%	281.2	257.2	24.0	9%
NGL sales, MBbl/d (3)	60.2	54.9	5.3	10%	58.9	55.6	3.3	6%
Condensate sales, MBbl/d (3)	3.0	3.1	(0.1)	(3%)	2.9	3.0	(0.1)	(3%)
Average realized prices (4):								
Natural gas, $/MMBtu	4.03	3.99	0.04	1%	3.96	4.29	(0.33)	(8%)
NGL, $/gal	1.29	0.85	0.44	52%	1.22	0.90	0.32	36%
Condensate, $/Bbl	85.99	72.10	13.89	19%	91.99	73.82	18.17	25%

(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 period and the denominator is the number of calendar days during the period.

(4) Average realized prices exclude the impact of hedging activities.

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

The $25.0 million increase in gross margin for 2011 was primarily due to higher NGL and condensate sales prices ($106.1 million), higher natural gas and NGL sales volumes ($32.4 million) and higher fee based and other revenues ($0.9 million), partially offset by higher product purchases ($113.7 million) and lower condensate sales volumes ($0.7 million). The increase in plant inlet volumes was largely attributable to new well connects throughout the systems, particularly North Texas, SAOU and Sand Hills, partially offset by operational outages and production declines at the Versado system. Natural gas sales increased on higher throughput and a decrease in take-in-kind volumes.

The $2.8 million increase in operating expenses was primarily due to higher fuel, utilities and catalysts expenses ($0.9 million), higher compensation and benefit costs ($1.0 million) and higher contract and professional service expenses ($0.4 million).

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

The $48.9 million increase in gross margin for 2011 was primarily due to higher NGL and condensate sales prices ($225.6 million), higher natural gas and NGL volumes ($61.9 million) and higher fee based and other revenues ($3.1 million), partially offset by higher product purchases ($214.5 million), lower natural gas sales prices ($24.8 million), and lower condensate sales volumes ($2.2 million). The increase in plant inlet volumes was largely attributable to new well connects throughout the systems, particularly North Texas and SAOU, partially offset by the impact of severe cold weather in the first quarter of 2011 and operational outages in the first quarter and third quarter of 2011and production declines at the Versado system. Natural gas sales increased on higher throughput and a decrease in take-in-kind volumes.

The $12.7 million increase in operating expenses was primarily due to higher fuel, utilities and catalysts expenses ($3.7 million), higher system maintenance expenses ($3.0 million) due to severe cold weather and operational outages in the first quarter of 2011, higher compensation and benefit costs ($3.8 million) and higher contract and professional service expenses ($2.5 million).

Coastal Gathering and Processing

	Three Months Ended September 30,		2011 vs. 2010		Nine Months Ended September 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
				($ in millions)				
Gross margin	$52.9	$34.2	$18.7	55%	$156.6	$106.3	$50.3	47%
Operating expenses	13.1	10.7	2.4	22%	34.8	31.4	3.4	11%
Operating margin	$39.8	$23.5	$16.3	69%	$121.8	$74.9	$46.9	63%
Operating statistics:								
Plant natural gas inlet, MMcf/d (1),(2),(3)	1,458.8	1,632.7	(173.9)	(11%)	1,548.3	1,714.5	(166.2)	(10%)
Gross NGL production, MBbl/d	46.3	51.0	(4.7)	(9%)	49.1	50.5	(1.4)	(3%)
Natural gas sales, Bbtu/d (3),(4)	256.6	293.1	(36.5)	(12%)	261.0	306.2	(45.2)	(15%)
NGL sales, MBbl/d (4)	41.6	42.4	(0.8)	(2%)	43.0	44.0	(1.0)	(2%)
	0.2	0.2	-	-	0.3	0.6	(0.3)	(50%)

Condensate sales, MBbl/d (4)								
Average realized prices (5):								
Natural gas, $/MMBtu	4.21	4.40	(0.19)	(4%)	4.24	4.64	(0.40)	(9%)
NGL, $/gal	1.35	0.93	0.42	45%	1.30	1.00	0.30	30%
Condensate, $/Bbl	107.72	72.42	35.30	49%	102.38	78.45	23.93	31%

The major Non-Partnership results of operations relate to:

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas proceesing plant.

(2) The mahority 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.

(5) Average realized prices exclude the impact of hedging activities.

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

The $18.7 million increase in gross margin for 2011 is primarily due to higher NGL and condensate sales prices ($68.0 million), partially offset by an increase in product purchases ($26.8 million), and by decreases in commodity sales volumes ($17.7 million), natural gas sales prices ($4.5 million) and fee-based and other revenues ($0.3 million). The decrease in plant inlet volumes was largely attributable to a decline in traditional wellhead and offshore supply volumes. The decreased NGL sales volumes were primarily due to lower throughput and NGL production volumes. Natural gas sales volumes decreased due to lower inlet volumes.

The $2.4 million increase in operating expenses was primarily due to higher compensation and benefit costs ($0.4 million), higher contract and professional service expenses ($0.6 million) and higher miscellaneous expenses ($1.3 million).

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

The $50.3 million increase in gross margin for 2011 is primarily due to an increase in NGL and condensate sales prices ($148.8 million), an increase in fee-based and other revenues ($2.0 million) and a decrease in product purchases ($4.9 million), partially offset by a decrease in natural gas sales prices ($28.7 million) and a decrease in commodity sales volumes ($76.7 million). The decrease in plant inlet volumes was largely attributable to a decline in traditional wellhead and offshore supply volumes. The decreased NGL sales volumes were primarily due to lower throughput and NGL production volumes. Natural gas sales volumes decreased due to lower inlet volumes.

The $3.4 million increase in operating expenses was primarily due to higher compensation and benefit costs ($0.9 million), higher contract and professional service expenses ($0.2 million) and higher miscellaneous expenses ($1.7 million).

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended September 30,		2011 vs. 2010		Nine Months Ended September 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
	($ in millions)							
Gross margin	$ 60.1	$ 43.1	$ 17.0	39%	$ 160.3	$ 121.5	$ 38.8	32%
Operating expenses	30.0	19.5	10.5	54%	74.4	68.6	5.8	8%
Operating margin	$ 30.1	$ 23.6	$ 6.5	28%	$ 85.9	$ 52.9	$ 33.0	62%
Operating statistics: (1)								
Fractionation volumes, MBbl/d	290.4	224.6	65.8	29%	260.1	220.9	39.2	18%
Treating volumes, MBbl/d	23.3	23.8	(0.5)	(2%)	20.5	17.8	2.7	15%

(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 period and the denominator is the number of calendar days during the period.

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

The $17.0 million increase in gross margin primarily reflects increased fractionation volumes ($13.1 million) and higher terminaling and storage revenue ($3.4 million). Growth in terminaling and storage revenue is primarily due to increased supply services to petrochemical customers at the Mont Belvieu terminal and higher LPG exports at the Galena Park terminal. Additionally, operations of the recently acquired Channelview Terminal and one full quarter of operations of the 78 MBbl/d expansion of the Cedar Bayou facility resulted in higher throughput and increased gross margin.

The $10.5 million increase in operating expenses was primarily due to increases in natural gas volumes for fuel to fractionators due to the expansion of the Cedar Bayou fractionation facility, utilities ($2.9 million), NGL transportation fees ($2.5 million), higher costs associated with fractionation maintenance ($2.3 million), contractor and professional services ($1.5 million) and compensation and benefit costs ($1.4 million).

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Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

The $38.8 million increase in gross margin reflects higher terminaling and storage revenue ($14.7 million) and increased fractionation volumes ($21.3 million). Growth in terminaling and storage revenue is primarily due to increased supply services to petrochemical customers at the Mont Belvieu terminal and higher LPG exports at the Galena Park terminal. Additionally, two full quarters of operations of the recently acquired Channelview Terminal and of the 78 MBbl/d expansion of the Cedar Bayou facility resulted in higher throughput and increased gross margin.

The $5.8 million increase in operating expenses was primarily due to increases in natural gas volumes for fuel to fractionators due to the expansion of the Cedar Bayou fractionation facility, utilities ($5.1 million), compensation and benefits ($3.4 million), NGL transportation fees ($3.4 million), maintenance ($2.4 million) and contractor and professional services ($1.4 million), partially offset by a more favorable system product volume gain ($8.0 million) and a decrease in miscellaneous expenses ($1.5 million).

Marketing and Distribution

	Three Months Ended September 30,		2011 vs. 2010		Nine Months Ended September 30,		2011 vs. 2010	
	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
	($ in millions)							
Gross margin	$30.1	$26.4	$3.7	14%	$116.0	$82.3	$33.7	41%
Operating expenses	10.4	11.4	(1.0)	(9%)	33.2	33.5	(0.3)	(1%)
Operating margin	$19.7	$15.0	$4.7	31%	$82.8	$48.8	$34.0	70%
Operating statistics: (1)								
Natural gas sales, BBtu/d	962.1	612.6	349.5	57%	829.1	630.1	199.0	32%
NGL sales, MBbl/d	264.5	242.9	21.6	9%	267.3	241.3	26.0	11%
Average realized prices:								
Natural gas, $/MMBtu	4.10	4.22	(0.12)	(3%)	4.15	4.50	(0.35)	(8%)
NGL realized price, $/gal	1.32	0.95	0.37	39%	1.32	1.06	0.26	25%

(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 period and the denominator is the number of calendar days during the period.

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

The $3.7 million increase in gross margin was due to higher NGL volumes ($79.0 million) and natural gas volumes ($135.6 million), higher NGL prices ($386.0 million) and higher fee-based and other revenues ($13.6 million), offset by lower natural gas prices ($10.7 million) and increased product purchases ($599.5 million). Increased NGL export sales contributed to a higher operating margin in 2011. Natural gas sales volumes increased due to higher purchases for resale.

Operating expenses decreased by $1.0 million due to lower contractor and professional services expenses ($1.3 million) offset by higher compensation benefits ($0.3 million).

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

The $33.7 million increase in gross margin was due to higher NGL volumes ($314.6 million) and natural gas volumes ($244.4 million), higher NGL prices ($789.6 million) and higher fee-based and other revenues ($25.7 million), offset by lower natural gas prices ($79.0 million) and increased product purchases ($1,269.7 million). Factors contributing to a higher operating margin in 2011 included increased NGL export sales and the positive impact of a contract settlement ($7.5 million) related to the current contract period of a multi-year propane exchange agreement. The contract, as restructured, provides for future payments during future contract periods through November 2014. Natural gas sales volumes increased due to higher purchases for resale.

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Other

	Three Months Ended September 30, 2011	2010	Change	Nine Months Ended September 30, 2011	2010	Change
			(In millions)			
Gross margin	$(10.8)	$7.1	$(17.9)	$(28.4)	$7.0	$(35.4)
Operating margin	$(10.8)	$7.1	$(17.9)	$(28.4)	$7.0	$(35.4)

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

The following table provides a breakdown of the Partnership's hedge results by product:

	Three Months Ended September 30, 2011	2010	Change	Nine Months Ended September 30, 2011	2010	Change
			(In Millions)			
Natural Gas	$6.4	$7.8	$(1.4)	$14.2	$14.8	$(0.6)
NGL	(15.8)	(0.7)	(15.1)	(38.0)	(6.8)	(31.2)
Crude	(1.4)	-	(1.4)	(4.6)	(1.0)	(3.6)
	$(10.8)	$7.1	$(17.9)	$(28.4)	$7.0	$(35.4)

Liquidity and Capital Resources

As a result of our conveyances of all of our remaining operating assets to the Partnership, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See "Item 1A. Risk Factors" in this Quarterly Report and our Annual Report for the year ended December 31, 2010. As of September 30, 2011, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs; and
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing a 13.7% limited partnership interest.

Our ownership of the general partner interest entitles us to receive:

- 2% of all cash distributed in respect for that quarter.

Our ownership of the IDR's of the Partnership entitles us to receive:

- 13% of all cash distributed in a quarter after $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

- 23% of all cash distributed in a quarter after $0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and

- 48% of all cash distributed in a quarter after $0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

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On October 11, 2011, the Partnership announced that the board of directors of its General Partner declared a quarterly distribution for the three months ended September 30, 2011 of $0.5825 per common unit, or an annual rate of $2.33 per common unit. Based on these distribution rates, we will receive quarterly distributions of $6.8 million, or $27.1 million on an annualized basis, in respect of our common units in the Partnership, and based on these distribution rates, we will receive quarterly distributions of $8.8 million and $1.2 million, or $35.3 million and $4.8 million on an annualized basis, based on our IDRs and 2% general partner interests.

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership securities, less the expenses of being a public company, other general and administrative expenses, federal income taxes, capital contributions to the Partnership and reserves established by our board of directors.

Dividends since our initial public offering on December 10, 2010 through September 30, 2011 were as follows:

Date Paid	For the Three Months Ended	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock	
		(In millions, except per share amounts)				
August 16, 2011	June 30, 2011	$ 12.3	$ 11.9	$ 0.4	$ 0.2900	
May 13, 2011	March 31, 2011	11.5	11.2	0.3	0.2725	
February 14, 2011	December 31, 2010	2.6	2.5	0.1	0.0616	(2)

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.
(2) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

On October 11, 2011, we announced a quarterly dividend of $0.3075 per share of our common stock for the three months ended September 30, 2011, or $1.232 per share on an annualized basis. The declared dividend totals $13.0 million, including $0.4 million with respect to accrued dividends related to unvested restricted stock grants. The cash dividend of $12.6 million will be paid on November 15, 2011.

As of September 30, 2011, we had $154.1 million of cash on hand, including $68.9 million of cash belonging to the Partnership. We do not have access to the Partnership’s cash as it is restricted for the use of the Partnership. We have the ability to use $85.2 million of the cash on hand and available to us to satisfy our aggregate tax liability of approximately $80.5 million over the next fourteen years associated with our sales of assets to the Partnership and related financings, as well as to fund the reimbursement of certain capital expenditures to the Partnership associated with its acquisition of Versado. In addition, we have a contingent obligation to contribute to the Partnership limited distribution support in any quarter through 2011 if and to the extent the Partnership has insufficient available cash to fund a distribution of $0.5175 per unit, limited to $8.0 million per quarter. We have not yet and do not currently expect to make any payments pursuant to this distribution support obligation.

Our consolidated risk management position has moved from a net liability of $22.9 million as of December 31, 2010 to a net asset of $10.6 million as of September 30, 2011. The Partnership terminated its interest rate swap contracts this quarter, which eliminated a liability of $23.0 million from our balance sheet. Additionally, forward prices for crude and natural gas have decreased to levels below the fixed prices the Partnership receives on its derivative contracts. Therefore, expected future receipts on these contracts are greater than expected future payments, resulting in a net asset position. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges.

Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Our and the Partnership's cash generated from operations has been sufficient to finance 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, primarily from distributions received from the Partnership 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 and collateral requirements. Our future cash flows will consist of distributions to us from our interests in the Partnership, from which we intend to make quarterly cash dividends to our stockholders from available cash.

The impact on us of changes in the Partnership's distribution levels will vary depending on several factors, including the Partnership's total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read "Item 1A. Risk Factors" in this Quarterly Report and our Annual Report for the year ended December 31, 2010 for more information about the risks that may impact your investment in us.

A significant portion of the Partnership's capital resources may be 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 and the Partnership 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. As of September 30, 2011, we had no outstanding letter of credit postings and the Partnership had $88.3 million.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. The Partnership's working capital requirements are primarily due to changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that the Partnership buys and sells. In general, the Partnership's working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, the Partnership's 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 the Partnership's customers or paid to its suppliers can also cause fluctuations in working capital because the Partnership settles with most of its larger suppliers and customers on a monthly basis and often near the end of the month. The Partnership expects that its future working capital requirements will be impacted by these same factors. The Partnership expects that cash flows provided by operating activities and availability under its credit facility will be sufficient to meet its operating requirements for the next twelve months.

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Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities for the periods indicated. See "Statement of Cash Flows – Partnership versus Non-Partnership" for a detailed presentation of cash flow activity:

	Nine Months Ended September 30,					
	2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - NonPartnership
	(In millions)					
Net cash provided by (used in):						
Operating activities	$ 164.6	$ 191.3	$ (26.7)	$ 126.0	$ 238.9	$ (112.9)
Investing activities	(390.1)	(387.2)	(2.9)	(80.7)	(79.3)	(1.4)
Financing activities	191.2	188.5	2.7	52.3	(196.0)	248.3

Non-Partnership Cash Flow Operating Activities

The operating activities of TRC – Non-Partnership primarily relate to the payment of interest and taxes.

Partnership Cash Flow Operating Activities

The Partnership's 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 the Partnership's 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 the Partnership's operating cash flows using the direct method as a supplement to the presentation in the Partnership's financial statements.

	For the Nine Months Ended September 30,		
	2011	2010	Variance
Cash flows from operating activities:			
Cash received from customers	$5,005.9	$3,993.2	$1,012.7
Cash received (paid) on derivative transactions (1)	(47.7)	28.5	(76.2)
Cash paid for:			
Product purchases	(4,379.5)	(3,478.5)	(901.0)
Operating expenses	(211.3)	(192.5)	(18.8)
General and administrative expenses (2)	(95.2)	(52.4)	(42.8)
Cash distributions from equity investment	3.7	3.7	-
Interest paid - net	(81.6)	(60.7)	(20.9)
Income taxes paid	(2.3)	(2.3)	-
Other cash receipts (payments)	(0.7)	(0.1)	(0.6)
Net cash provided by operating activities	$191.3	$238.9	$(47.6)

(1) The change in cash paid to derivative counterparties reflects the change in our net position from in-the-money for the period ending September 30, 2010 to out-of-the-money for the period ending September 30, 2011, and a payment for interest rate swap termination in the amount of $23.0 million, excluding $1.2 million accrued interest, in September 2011.
(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.

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Non-Partnership Cash Flow Investing Activities

Net cash provided by investing activities consisted of $2.9 million in outlays for property, plant and equipment for the nine months ended 2011 compared to $1.4 million in 2010.

Partnership Cash Flow Investing Activities

Net cash used in investing activities increased by $307.9 million for the nine months ended September 30, 2011 compared to 2010. The increase was primarily due to the Partnership's petroleum logistics acquisitions of $164.2 million and a $103.5 million increase in expansion capital projects in gathering and processing assets and in fractionation assets. The Partnership also invested $11.9 million in equity contributions associated with the expansion at Gulf Coast Fractionators.

Non-Partnership Cash Flow Financing Activities

Net cash provided by financing activities decreased by $245.6 million. During 2010, we received from the Partnership $740.2 million in repayments of affiliated indebtedness, and received $224.7 million from the sale of Partnership interests. These proceeds were primarily used to pay $419.9 million in dividends to common and common equivalent shareholders and preferred shareholders, and $454.5 million in outstanding balances on our loan facilities during 2010. Distributions to us from the Partnership increased $9.4 million in 2011 compared to 2010 primarily from a $11.5 million increase in distributions related to our incentive distribution rights, offset by a $3.0 million decrease in limited partner distributions due to our sale of Partnership interests during 2010.

Partnership Cash Flow Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2011 was $188.5 million compared to a net cash used in financing activities of $196.0 million for the nine months ended September 30, 2010. The increase was due to two primary factors: changes in the Partnership's equity offerings and financing activities and distributions.

Net proceeds from public offerings, issuance of senior notes and borrowings under the Partnership's credit facility less repayments on the Partnership's credit facility increased $269.6 million from $101.7 million for the nine months ended September 30, 2010 to $371.3 million for the nine months ended September 30, 2011. The Partnership's primary financing activities that occurred during the nine months ended September 30, 2011 were:

- On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units in them 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 the Partnership issued an additional 1,200,000 common units, providing net proceeds of approximately $38.8 million. In addition, we, as the general partner, contributed $6.3 million for 187,755 general partner units to maintain our 2% general partner interest in the Partnership.

- On February 2, 2011, the Partnership closed a private placement of $325.0 million in aggregate principal amount of the Partnership's 6 % Notes resulting in net proceeds of $318.8 million.

- On February 4, 2011, the Partnership exchanged an additional $158.6 million principal amount of the Partnership's 6 % Notes for $158.6 million aggregate principal amount of its 11¼% Notes. In conjunction with the exchange the Partnership paid a cash premium of $28.6 million including $0.9 million of accrued interest.

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

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Partnership Cash Distributions

The following table shows the historical distributions of the Partnership to us for 2011 and 2010 with respect of our 2% general partner interest, the associated IDRs and actual common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods. The amount of these Partnership distributions available for distribution to us and the Partnership's shareholders will be after reserves are established for the Partnership's capital contributions, debt service requirements, general, administrative and other expenses, future distributions and other miscellaneous uses of cash:

			Cash Distributions (1)					
Date Paid	For the Three Months Ended	Cash Distribution Per Limited Partner Unit	Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (2)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
		(In millions, except per unit amounts)						
August 12, 2011	June 30, 2011	$ 0.5700	$ 6.6	$ 1.2	$ 7.8	$ 15.6	$ 0.2900	$ 12.3
May 13, 2011	March 31, 2011	0.5575	6.5	1.1	6.8	14.4	0.2725	11.5
February 14, 2011	December 31, 2010	0.5475	6.4	1.1	6.0	13.5	0.0616 (3)	2.6
November 12, 2010	September 30, 2010	0.5375	6.3	0.9	4.6	11.8	N/A	N/A
August 13, 2010	June 30, 2010	0.5275	6.1	0.8	3.5	10.4	N/A	N/A
May 14, 2010	March 31, 2010	0.5175	6.0	0.8	2.8	9.6	N/A	N/A
February 12, 2010	December 31, 2009	0.5175	10.4	0.8	2.8	14.0	N/A	N/A

(1) On October 11, 2011, the Partnership announced a cash distribution of $0.5825 per common unit on its outstanding common units for the three months ended September 30, 2011, to be paid on November 14, 2011. The distribution to be paid is $42.6 million to the Partnership's third-party limited partners, and $6.8 million, $8.8 million and $1.2 million to us for our ownership of common units, incentive distribution rights and our 2% general partner interest in the Partnership. We expect to distribute to our shareholders $12.6 million on November 15, 2011.

(2) Distributions to us are comprised of amounts attributable to our (i) limited partner units, (ii) general partner units, and (iii) IDRs.

(3) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

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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:

	Nine Months Ended September 30,					
	2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Gross additions to property, plant and equipment	$ 243.9	$ 242.1	$ 1.8	$ 83.8	$ 82.1	$ 1.7
Change in accruals	(0.6)	(1.7)	1.1	0.4	0.4	-
Cash expenditures	$ 243.3	$ 240.4	$ 2.9	$ 84.2	$ 82.5	$ 1.7

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 the Partnership's gathering system is generally paid for by the natural gas producer. However, the Partnership expects to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure and the expansion of its logistics assets.

We and the Partnership categorize 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, and fund acquisitions of businesses or assets.

	Nine Months Ended September 30,					
	2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Capital expenditures:						
Business acquisitions	$ 164.2	$ 164.2	$ -	$ -	$ -	$ -
Expansion	156.4	155.9	0.5	52.7	52.4	0.3
Maintenance	58.5	57.2	1.3	31.1	29.7	1.4
	$ 379.1	$ 377.3	$ 1.8	$ 83.8	$ 82.1	$ 1.7

Including business acquisitions, the Partnership estimates that their total capital expenditures for 2011 will be approximately $520 million gross and $480 million net of non-controlling interest share and reimbursements. The Partnership also estimates that of the $480 million net capital expenditures, approximately 15% will be for maintenance. Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, the Partnership anticipates that over time they will invest significant amounts of capital to grow and acquire assets. Major capital projects include:

- $360 million expansion project at CBF to add a fourth fractionation train and related infrastructure enhancements at Mont Belvieu;
- $250 million expansion of the Partnership's Mont Belvieu complex and the Partnership's existing import/export marine terminal at Galena Park to export international grade propane;
- $150 million for a new cryogenic processing plant and associated projects for the Partnership's North Texas System;
- $60 million expansion of the Partnership's petroleum logistics assets;
- $40 million capital expansion project to expand the gathering and processing capability of the Partnership's North Texas System;
- $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;
- $30 million capital expansion project to expand the gathering and processing capability of our SAOU System;
- $13 million expansion of the Partnership's dock facilities and related infrastructure enhancements at Galena Park; and
- the Partnership's 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.

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The Partnership expects to fund future capital expenditures with funds generated from their operations, borrowings under their 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.

The Partnership's principal market risks are its exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, changes in interest rates, as well as nonperformance by its customers. Neither we nor the Partnership use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority of the Partnership's revenues are derived from percent-of-proceeds contracts under which it receives 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 the Partnership's control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its 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.

The Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. The Partnership believes this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. The NGL hedges' fair values are based on published index prices for delivery at Mont Belvieu through 2013. The natural gas hedges' fair values are based on published index prices for delivery at various locations which closely approximate the actual NGL and natural gas delivery points. A portion of the Partnership's 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. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. The Partnership's 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 currently secured by a first priority lien in the collateral securing its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders. Absent 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, the Partnership expects to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if a counterparty's exposure to the Partnership's credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in the Partnership's creditworthiness. A purchased put (or floor) transaction does not create credit exposure to the Partnership for the Partnership's counterparties.

For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the three and nine months ended September 30, 2011, our consolidated operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $(10.8) million and $(28.4) million. During the three and nine months ended September 30, 2010, our consolidated operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $7.1 million and $7.0 million. The net hedge adjustments that impact our consolidated revenues include amortization of other comprehensive income (“OCI”) related to the Partnership’s acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

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As of September 30, 2011, the Partnership 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 October 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			$ 5.7
Swap	IF-WAHA	6.61		14,850		13.5
Swap	IF-WAHA	5.28			7,230	1.6
Total Swaps			23,750	14,850	7,230	
Swap	IF-PB	4.58	6,565			0.6
Swap	IF-PB	4.98		10,200		3.4
Swap	IF-PB	5.23			7,084	1.6
Total Swaps			6,565	10,200	7,084	
Swap	IF-NGPL MC	5.66	8,155			1.5
Swap	IF-NGPL MC	6.03		6,740		4.7
Swap	IF-NGPL MC	4.89			2,775	0.3
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					0.3
						$ 33.2

NGL						
Instrument Type	Index	Price $/Gal	Barrels per day 2011	2012	2013	Fair Value (In millions)
Swap	OPIS-MB	0.92	10,118			$ (14.0)
Swap	OPIS-MB	0.95		9,361		(20.3)
Swap	OPIS-MB	0.98			4,150	(3.9)
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	-	
			10,371	9,655	4,150	

Total Sales							$ (37.6)

Condensate Instrument Type	Index	Price $/Bbl	Barrels per day 2011	2012	2013	2014	Fair Value (In millions)
Swap	NY-WTI	87.87	1,730				$ 1.3
Swap	NY-WTI	91.37		1,660			6.2
Swap	NY-WTI	91.34			1,795		6.2
Swap	NY-WTI	90.03				700	1.3
Total Sales			1,730	1,660	1,795	700	$ 15.0

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These contracts may expose the Partnership to the risk of financial loss in certain circumstances. Its hedging arrangements provide 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 they have been hedged, the Partnership will receive less revenue on the hedged volumes than it would receive in the absence of hedges.

The Partnership accounts for the fair value of its 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. The value of the NGL derivative contracts is determined 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 the Partnership is 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 10 to the Consolidated Financial Statements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We and the Partnership are exposed to the risk of changes in interest rates. We are exposed to interest rate changes due to our variable rate Holdco loan facility. The Partnership is exposed to interest rate changes as a result of variable rate borrowings under the senior secured revolving credit facility of the Partnership. To the extent that interest rates increase, interest expense for our Holdco loan facility and the Partnership's revolving debt will also increase. As of September 30, 2011, the Partnership had variable rate borrowings of $535.0 million, and we had variable rate borrowings of $89.3 million. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by $5.4 million and would impact the TRC Non-Partnership annual interest expense by $0.9 million.

Counterparty Risk – Credit and Concentration

Credit Risk. The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its 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, the Partnership's 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, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of September 30, 2011, affiliates of Barclays PLC ("Barclays") and Natixis accounted for 35% and 15% of the Partnership's counterparty credit exposure related to commodity derivative instruments. Barclays and Natixis 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. The Partnership extends credit to customers and other parties in the normal course of business. The Partnership has established various procedures to manage its credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. The Partnership also uses prepayments and guarantees to limit credit risk to ensure that its 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 September 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 has been 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 September 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 13 – 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 and the Partnership's 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 the Partnership as well as natural gas exploration and production operators to incur increased capital expenditures and operating costs as well as cause the Partnership to experience reduced demand for its 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 the Partnership's 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 the Partnership's customer's as well as the Partnership's operations including the installation of new equipment. Compliance with such rules could result in significant costs as well as delays in well completions by the Partnership's customers, including increased capital expenditures and operating costs, which may adversely impact the Partnership's business. Moreover, the incurrence of such expenditures and costs by the Partnership's exploration and production customers' could result in reduced production by those customers and thus translate into reduced demand for the Partnership's gathering, processing or fractionation services.

Pipeline safety legislation and regulations expanding integrity management programs or requiring the use of certain safety technologies could require the Partnership to use more comprehensive and stringent safety controls and subject the Partnership to increased capital and operating costs.

Congress is currently considering adopting legislation that would establish more stringent pipeline safety requirements. The proposed legislation, if adopted, could impose strengthened pipeline integrity management system requirements, including expanding those requirements to pipelines outside high consequence areas, as well as more stringent non-integrity pipeline measures such as the use of automatic or remote-controlled shut-off valves on pipeline facilities. In addition, on May 5, 2011, the federal Pipeline and Hazardous Materials Safety Administration, or "PHMSA" published a final rule expanding pipeline safety requirements including added reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. Also, on August 25, 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines, gathering lines and related facilities including, among other things, whether PHMSA should: (i) re-define the term "gathering line," (ii) require the submission of annual, incident and safety-related conditions reports by operators of all gathering lines, (iii) establish a new, risk-based regime of safety requirements for large-diameter, high pressure gas gathering lines in rural locations, (iv) enhance the requirements for internal corrosion control of gathering lines, and (v) apply its gas integrity management requirements to onshore gas gathering lines. The adoption of legislation or regulations that apply more comprehensive or stringent safety standards to gathering lines could require the Partnership to install new or modified safety controls, pursue added capital projects, or conduct maintenance programs on an accelerated basis, all of which could require the Partnership to incur increased operational costs that could be significant and have a material adverse effect on the Partnership's financial position or results of operations.

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.

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Item 6. Exhibits.

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	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)).
3.4	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)).
3.5	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)).
3.6	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)).
3.7	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)).
3.8	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.9	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 25, 2011 (File No. 001-33303)).
3.10	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	Supplemental Indenture dated October 28, 2011 to Indenture dated June 18, 2008, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries 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 4.1 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 4, 2011 (File No. 001-33303)).
10.2	Supplemental Indenture dated October 28, 2011 to Indenture dated August 13, 2010, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries 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 4.2 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 4, 2011 (File No. 001-33303)).
10.3	Supplemental Indenture dated October 28, 2011 to Indenture dated February 2, 2011, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries 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 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 4, 2011 (File No. 001-33303)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
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*	Filed herewith
**	Furnished herewith

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Signatures

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

Targa Resources Corp.
(Registrant)

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

Date: November 4, 2011

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Exhibit Index

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	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)).
3.4	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)).
3.5	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)).
3.6	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)).
3.7	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)).
3.8	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.9	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 25, 2011 (File No. 001-33303)).
3.10	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	Supplemental Indenture dated October 28, 2011 to Indenture dated June 18, 2008, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries of Targa

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