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

FORM 10-Q

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

For the quarterly period ended September 30, 2015

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐

(Do not check if a 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 ☑.

As of October 30, 2015, there were 184,847,901 common units representing limited partner interests and 3,772,406 general partner units outstanding. As of October 30, 2015, there were 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units outstanding.

PART I—FINANCIAL INFORMATION

PART II—OTHER INFORMATION

SIGNATURES

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to various 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"), crude oil and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation and markets;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; including with respect to the Atlas mergers (as defined below) which were completed on February 27, 2015 between Targa Resources Corp. ("Targa," "Parent" or "TRC") and Atlas Energy, L.P., a Delaware limited partnership ("ATLS") and between Atlas Pipeline Partners, L.P., a Delaware limited partnership ("APL") and us;
- general economic, market and business conditions; and
- the risks described elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2014 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

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

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

Bbl	Barrels (equal to 42 U.S. gallons)
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
LIBOR	London Interbank Offered Rate
NYSE	New York Stock 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
NG-NYMEX	NYMEX, Natural Gas

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			September 30, 2015	December 31, 2014
			(Unaudited) (In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 92.8	$ 72.3
Trade receivables, net of allowances of $0.0 million			620.5	566.8
Inventories			151.1	168.9
Assets from risk management activities			92.3	44.4
Other current assets			8.7	3.8
Total current assets			965.4	856.2
Property, plant and equipment			11,791.6	6,514.3
Accumulated depreciation			(2,041.4)	(1,689.7)
Property, plant and equipment, net			9,750.2	4,824.6
Goodwill			551.4	-
Intangible assets, net			1,695.7	591.9
Long-term assets from risk management activities			45.4	15.8
Investments in unconsolidated affiliates			264.2	50.2
Other long-term assets			50.9	38.5
Total assets			$ 13,323.2	$ 6,377.2
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities			$ 650.5	$ 592.7
Accounts payable to Targa Resources Corp.			39.5	53.2
Liabilities from risk management activities			4.3	5.2
Accounts receivable securitization facility			135.5	182.8
Total current liabilities			829.8	833.9
Long-term debt			5,336.4	2,783.4
Long-term liabilities from risk management activities			4.0	-
Deferred income taxes, net			22.1	13.7
Other long-term liabilities			73.7	57.8
Contingencies (see Note 16)				
Owners' equity:				
Limited partners	Issued	Outstanding	4,931.5	2,384.1
September 30, 2015	185,049,203	184,847,487		
December 31, 2014	118,652,798	118,586,056		
General partner			1,747.5	78.6
September 30, 2015	3,772,397	3,772,397		
December 31, 2014	2,420,124	2,420,124		
Receivables from unit issuances			-	(1.0)
Accumulated other comprehensive income (loss)			78.6	60.3
Treasury units at cost (201,716 units as of September 30, 2015, and 66,742 as of December 31, 2014)			(10.0)	(4.8)
			6,747.6	2,517.2
Noncontrolling interests in subsidiaries			309.6	171.2
Total owners' equity			7,057.2	2,688.4
Total liabilities and owners' equity			$ 13,323.2	$ 6,377.2

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(Unaudited) (In millions, except per unit amounts)			
Revenues:				
Sales of commodities	$ 1,321.3	$ 2,009.2	$ 4,119.6	$ 5,853.3
Fees from midstream services	310.8	279.1	891.6	730.4
Total revenues	1,632.1	2,288.3	5,011.2	6,583.7
Costs and expenses:				
Product purchases	1,172.4	1,880.5	3,677.7	5,412.2
Operating expenses	133.6	112.8	381.8	323.6
Depreciation and amortization expenses	165.8	87.5	448.3	252.8
General and administrative expenses	42.9	40.4	130.1	115.3
Other operating (income) expense	0.1	(4.3)	0.6	(5.3)
Income from operations	117.3	171.4	372.7	485.1
Other income (expense):				
Interest expense, net	(64.1)	(36.0)	(177.2)	(104.1)
Equity earnings (loss)	(1.6)	4.7	(1.1)	13.8
Loss from financing activities (see Note 10)	(0.5)	-	(0.5)	-
Other	1.8	(0.6)	(9.1)	(0.6)
Income before income taxes	52.9	139.5	184.8	394.2
Income tax (expense) benefit:				
Current	(0.2)	(0.9)	(0.7)	(2.6)
Deferred	0.6	(0.4)	0.3	(1.1)
	0.4	(1.3)	(0.4)	(3.7)
Net income	53.3	138.2	184.4	390.5
Less: Net income attributable to noncontrolling interests	4.8	9.9	17.3	30.9
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ 167.1	$ 359.6
Net income attributable to general partner	$ 44.9	$ 38.6	$ 132.0	$ 108.2
Net income attributable to limited partners	3.6	89.7	35.1	251.4
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ 167.1	$ 359.6
Net income per limited partner unit - basic	$ 0.02	$ 0.78	$ 0.21	$ 2.21
Net income per limited partner unit - diluted	$ 0.02	$ 0.78	$ 0.21	$ 2.20
Weighted average limited partner units outstanding - basic	184.8	115.1	168.1	113.9
Weighted average limited partner units outstanding - diluted	185.1	115.7	168.5	114.5

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Unaudited) (In millions)			
Net income	$ 53.3	$ 138.2	$ 184.4	$ 390.5
Other comprehensive income (loss):				
Commodity hedging contracts:				
Change in fair value	42.9	14.2	59.4	(4.5)
Settlements reclassified to revenues	(16.7)	0.8	(41.1)	11.6
Interest rate swaps:				
Settlements reclassified to interest expense, net	-	-	-	2.4
Other comprehensive income (loss)	26.2	15.0	18.3	9.5
Comprehensive income (loss)	79.5	153.2	202.7	400.0
Less: Comprehensive income attributable to noncontrolling interests	4.8	9.9	17.3	30.9
Comprehensive income attributable to Targa Resources Partners LP	$ 74.7	$ 143.3	$ 185.4	$ 369.1

See notes to consolidated financial statements.

Table of Contents

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

(Unaudited)
(In millions, except units in thousands)

	Limited Partner		General Partner		Receivables From Unit Issuances	Accumulated Other Comprehensive Income (Loss)	Treasury Units		Non-controlling Interests	Total
	Common	Amount	Units	Amount			Units	Amount		
Balance December 31, 2014	118,586	$ 2,384.1	2,420	$ 78.6	$ (1.0)	$ 60.3	67	$ (4.8)	$ 171.2	$ 2,688.4
Compensation on equity grants	-	12.8	-	-	-	-	-	-	-	12.8
Distribution equivalent rights	-	(1.9)	-	-	-	-	-	-	-	(1.9)
Issuance of common units under compensation program	405	-	-	-	-	-	-	-	-	-
Units tendered for tax withholding obligations	(135)	-	-	-	-	-	135	(5.2)	-	(5.2)
Equity offerings	7,377	315.4	-	-	-	-	-	-	-	315.4
Acquisition of APL	58,614	2,583.1	-	-	-	-	-	-	113.4	2,696.5
Contributions from Targa Resources Corp.	-	-	1,352	59.1	1.0	-	-	-	-	60.1
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(8.7)	(8.7)
Contributions from noncontrolling interests	-	-	-	-	-	-	-	-	16.4	16.4
Other comprehensive income (loss)	-	-	-	-	-	18.3	-	-	-	18.3
Net income	-	35.1	-	132.0	-	-	-	-	17.3	184.4
Distributions	-	(397.1)	-	(134.6)	-	-	-	-	-	(531.7)
Targa contribution - Special General Partner Interest (see Note 2)	-	-	-	1,612.4	-	-	-	-	-	1,612.4
Balance September 30, 2015	184,847	$ 4,931.5	3,772	$ 1,747.5	$ -	$ 78.6	202	$ (10.0)	$ 309.6	$ 7,057.2
Balance December 31, 2013	111,263	$ 2,001.9	2,271	$ 62.0	$ -	$ (6.1)	-	$ -	$ 160.6	$ 2,218.4
Compensation on equity grants	-	7.0	-	-	-	-	-	-	-	7.0
Distribution equivalent rights	-	(2.0)	-	-	-	-	-	-	-	(2.0)
Issuance of common units under compensation program	214	-	-	-	-	-	-	-	-	-
Units tendered for tax withholding obligations	(67)	-	-	-	-	-	67	(4.8)	-	(4.8)
Equity offerings	4,364	257.2	-	-	-	-	-	-	-	257.2
Contributions from Targa Resources Corp.	-	-	92	5.6	(0.4)	-	-	-	-	5.2
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	(26.8)	(26.8)
Other comprehensive income (loss)	-	-	-	-	-	9.5	-	-	-	9.5
Net income	-	251.4	-	108.2	-	-	-	-	30.9	390.5
Distributions	-	(260.7)	-	(102.1)	-	-	-	-	-	(362.8)
Balance September 30, 2014	115,774	$ 2,254.8	2,363	$ 73.7	$ (0.4)	$ 3.4	67	$ (4.8)	$ 164.7	$ 2,491.4

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2015	2014
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 184.4	$ 390.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	9.3	8.8
Compensation on equity grants	12.8	7.0
Depreciation and amortization expense	448.3	252.8
Accretion of asset retirement obligations	3.9	3.3
Deferred income tax expense (benefit)	(0.3)	1.1
Equity (earnings) loss of unconsolidated affiliates	1.1	(13.8)
Distributions received from unconsolidated affiliates	10.1	13.8
Risk management activities	53.2	0.9
(Gain) loss on sale or disposition of assets	(0.2)	(5.6)
Loss from financing activities	0.5	-
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	126.7	(40.4)
Inventory	31.2	(115.5)
Accounts payable and other liabilities	(143.2)	68.9
Net cash provided by operating activities	737.8	571.8
Cash flows from investing activities		
Outlays for property, plant and equipment	(625.3)	(571.7)
Business acquisition, net of cash acquired	(828.7)	-
Investment in unconsolidated affiliates	(6.6)	-
Return of capital from unconsolidated affiliates	1.1	4.2
Other, net	(3.0)	6.3
Net cash used in investing activities	(1,462.5)	(561.2)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	1,646.0	1,295.0
Repayments of credit facility	(1,211.0)	(1,115.0)
Borrowings from accounts receivable securitization facility	275.5	88.9
Repayments of accounts receivable securitization facility	(322.8)	(131.0)
Proceeds from issuance of senior notes	1,700.0	-
Redemption of APL senior notes	(1,168.8)	-
Costs in connection with financing arrangements	(20.7)	(2.7)
Proceeds from sale of common units	318.6	259.9
Repurchase of common units under compensation plans	(5.2)	(4.8)
Contributions received from General Partner	60.1	5.2
Contributions received from noncontrolling interests	16.4	-
Distributions paid to unitholders	(531.7)	(362.8)
Payment of distribution equivalent rights	(2.5)	(1.6)
Distributions paid to noncontrolling interests	(8.7)	(26.8)
Net cash provided by financing activities	745.2	4.3
Net change in cash and cash equivalents	20.5	14.9
Cash and cash equivalents, beginning of period	72.3	57.5
Cash and cash equivalents, end of period	$ 92.8	$ 72.4

See notes to consolidated financial statements.

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

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

Note 1 — Organization and Operations

Our Organization

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

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa. As of September 30, 2015, Targa owned a 10.6% interest in us in the form of 3,772,397 general partner units and 16,309,594 common units. In addition, Targa Resources GP LLC also owns our incentive distribution rights (“IDRs”), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter, exclusive of amounts reallocated to common unit-holders under the IDR Giveback Amendment (see Note 11-Partnership Units and Related Matters).

In connection with the Atlas mergers (see Note 4-Business Acquisitions), our Partnership Agreement was amended to provide for the issuance of a special general partner interest (“the Special GP Interest”) representing a capital account credit equal to the consideration paid by Targa for and resulting tax basis in the Atlas Pipeline Partners GP, LLC, a Delaware limited liability company and the general partner of APL (“APL GP”) acquired in the ATLS merger (see Note 4 – Business Acquisitions). The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to receive distributions in liquidation.

In connection with our issuance of 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Preferred Units”) in October 2015, our Partnership Agreement was amended and restated for the purpose of defining the preferences, rights, powers and duties of holders of our Preferred Units (see Note 11-Partnership Units and Related Matters).

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 18-Segment Information for certain financial information for our business segments.

The employees supporting our operations are employed by Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa’s centralized general and administrative services.

Subsequent Event

On November 2, 2015, we and Targa entered into an Agreement and Plan of Merger, by and among Targa, Spartan Merger Sub LLC, a subsidiary of Targa (“Merger Sub”), us and our general partner pursuant to which Targa will acquire all of our outstanding common units representing limited partner interests in us not already owned by Targa or its subsidiaries. Upon the terms and conditions set forth in the Merger Agreement, Merger Sub will be merged with and into us, with us continuing as the surviving entity and as a subsidiary of Targa (see Note 19 - Buy-in Acquisition).

Note 2 — Basis of Presentation

We have prepared these unaudited consolidated financial statements in accordance with 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. 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.

The February 27, 2015 Atlas mergers involved two separate legal transactions involving different groups of equity holders. For GAAP reporting purposes, these two mergers are viewed as a single integrated transaction. As such, the financial effects of the Targa consideration related to the ATLS merger have been reflected in these financial statements. As described in Note 1, our Partnership Agreement was amended to provide for the issuance of the Special GP Interest in us equal to the tax basis of the APL GP Interests acquired in the ATLS merger totaling $1.6 billion. The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to distributions in liquidation.

The unaudited consolidated financial statements for the three and nine months ended September 30, 2015 and 2014 include all adjustments that 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. Certain amounts in prior periods may have been reclassified to conform to the current year presentation.

Our financial results for the three and nine months ended September 30, 2015 are not necessarily indicative of the results that may be expected for the full year.

Note 3 — Significant Accounting Policies

Accounting Policy Updates

The accounting policies that we follow are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report. We have updated our policies during the nine months ended September 30, 2015 to include our accounting policy for goodwill related to the Atlas mergers.

Goodwill

Goodwill results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. Goodwill is not amortized, but is assessed annually to determine whether its carrying value has been impaired.

Impairment testing for goodwill is performed at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available, and segment management regularly reviews the operating results of that component.

Goodwill is subject to a test for impairment at least annually, as well as whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. We may first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount (including assigned goodwill) as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. If a two-step process goodwill impairment test is required, the first step involves comparing the fair value of the reporting unit to which goodwill has been allocated with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as a reduction of goodwill on our Consolidated Balance Sheets and a goodwill impairment loss on our Consolidated Statements of Operations.

Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016, with early adoption permitted. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than revolving credit facilities) be presented in the consolidated balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update deals solely with financial statement display matters; recognition and measurement of debt issuance costs are unaffected. Unamortized debt issuance costs of $40.2 million and $29.9 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014. In August 2015, the FASB issued ASU 2015-15, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. The amendment clarifies ASU 2015-03 and provides that an entity may defer and present debt issuance costs for a line-of-credit or other revolving credit facility arrangement as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the arrangement. Unamortized debt issuance costs of $6.5 million and $7.6 million for revolving credit facilities were included in Other long-term assets on the Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014. We will continue to include debt issuance costs for our line-of-credit and revolving credit facility arrangements in Other long-term assets upon adoption of ASU 2015-03. We plan to adopt these standards as of December 31, 2015.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 303): Simplifying the Measurement of Inventory*. Topic 303 currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This amendment has been adopted, with no impact on our consolidated financial statements or results of operations.

In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. The amendment defers the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) by one year. As a result of the amendment, Topic 606 is effective for the annual period beginning December 15, 2017, and for annual and interim periods thereafter, with early adoption permitted. Earlier adoption is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact of Topic 606 on our revenue recognition practices.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*. Topic 805 currently requires that adjustments to provisional amounts recorded in a business combination be recognized retrospectively as if the accounting had been completed at the acquisition date. The amendments in this update require that an acquirer recognize these measurement-period adjustments in the reporting period in which the adjustment amounts are determined, with the effect on earnings of changes in depreciation, amortization or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments require disclosure of the amount recorded in current-period earnings that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for us in 2016, with early adoption permitted. We adopted the amendments on September 30, 2015 and have recognized the measurement-period adjustments for the Atlas mergers determined in the three months ended September 30, 2015 in current period earnings. See Note 4 for additional information regarding the nature and amount of the measurement-period adjustments.

Note 4 –Business Acquisitions

2015 Acquisition

Atlas Mergers

On February 27, 2015, (i) Targa completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 13, 2014 (the "ATLS Merger Agreement"), by and among Targa, Targa GP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of Targa ("GP Merger Sub"), ATLS and Atlas Energy GP, LLC, a Delaware limited liability company and the general partner of ATLS ("ATLS GP"), and (ii) Targa and the Partnership completed the transactions contemplated by the Agreement and Plan of Merger (the "APL Merger Agreement" and, together with the ATLS Merger Agreement, the "Atlas Merger Agreements") by and among Targa, the Partnership, our general partner, Trident MLP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of the Partnership ("MLP Merger Sub"), ATLS, APL and APL GP. Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged (the "ATLS merger") with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged (the "APL merger" and, together with the ATLS merger, the "Atlas mergers") with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership.

While the Atlas mergers were two separate legal transactions, for GAAP reporting purposes, they are viewed as a single integrated transaction. As such, the financial effects of the ATLS Merger Consideration (as defined below) paid by Targa have been reflected in these financial statements.

In connection with the Atlas mergers, APL changed its name to "Targa Pipeline Partners LP," which we refer to as TPL, and ATLS changed its name to "Targa Energy LP."

In addition, prior to the completion of the Atlas mergers, ATLS, pursuant to a separation and distribution agreement entered into by and among ATLS, ATLS GP and Atlas Energy Group, LLC, a Delaware limited liability company ("AEG"), on February 27, 2015, (i) transferred its assets and liabilities other than those related to its "Atlas Pipeline Partners" segment, to AEG and (ii) effected a pro rata distribution to the ATLS unitholders of AEG common units representing a 100% interest in AEG (collectively, the "Spin-Off" and, together with the Atlas mergers, the "Atlas Transactions").

We acquired all of the outstanding units of APL for a total purchase price of approximately \$5.3 billion (including \$1.8 billion of acquired debt and all other assumed liabilities). Of the \$1.8 billion of debt acquired and other liabilities assumed, approximately \$1.2 billion of the acquired debt was tendered and settled upon the closing of the Atlas mergers via our January 2015 cash tender offers. These tender offers were in connection with, and conditioned upon, the consummation of the merger with APL. The merger with APL, however, was not conditioned on the consummation of the tender offers. On that same date, Targa acquired ATLS for a total purchase price of approximately \$1.6 billion (including all assumed liabilities).

Pursuant to the APL Merger Agreement, our general partner entered into an amendment to our Partnership Agreement, which we refer to as the IDR Giveback Amendment, in order to reduce aggregate distributions to TRC, as the holder of the Partnership's IDRs by (a) \$9,375,000 per quarter during the first four quarters following the APL merger, (b) \$6,250,000 per quarter for the next four quarters, (c) \$2,500,000 per quarter for the next four quarters and (d) \$1,250,000 per quarter for the next four quarters, with the amount of such reductions to be distributed pro rata to the holders of our outstanding common units.

TPL is a provider of natural gas gathering, processing and treating services primarily in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in south Texas. The Atlas mergers add TPL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The results of TPL are reported in our Field Gathering and Processing segment.

The APL merger was a unit-for-unit transaction with an exchange ratio of 0.5846 of our common units (the “APL Unit Consideration”) and $1.26 in cash for each APL common unit (the “APL Cash Consideration” and, with the APL Unit Consideration, the “APL Merger Consideration”), a $128.0 million total cash payment, of which $0.6 million was expensed at the acquisition date as the cash payment representing accelerated vesting of a portion of retained employees’ APL phantom awards. We issued 58,614,157 of our common units and awarded 629,231 replacement phantom unit awards with a combined value of approximately $2.6 billion as consideration for the APL merger (based on the $43.82 closing market price of a common unit on the NYSE on February 27, 2015). The cash component of the APL merger also included $701.4 million for the mandatory repayment and extinguishment at closing of the APL Senior Secured Revolving Credit Facility that was to mature in May 2017 (the “APL Revolver”), $28.8 million of payments related to change of control and $6.4 million of cash paid in lieu of unit issuances in connection with settlement of APL equity awards for AEG employees. In March 2015, Targa contributed $52.4 million to us to maintain its 2% general partner interest.

In addition, pursuant to the APL Merger Agreement, APL exercised its right under the certificate of designations of the APL 8.25% Class E cumulative redeemable perpetual preferred units (“Class E Preferred Units”) to redeem the APL Class E Preferred Units immediately prior to the effective time of the APL merger.

The ATLS merger was a stock-for-unit transaction with an exchange ratio of 0.1809 of Targa common stock, par value $0.001 per share (the “ATLS Stock Consideration”), and $9.12 in cash for each ATLS common unit (the ATLS Cash Consideration” and, with the ATLS Stock Consideration, the “ATLS Merger Consideration”), (a $514.7 million total cash payment). Targa issued 10,126,532 of its common shares and awarded 81,740 replacement restricted stock units with a combined value of approximately $1.0 billion for the ATLS merger (based on the $99.58 closing market price of a TRC common share on the NYSE on February 27, 2015). The cash component of the ATLS merger also included approximately $149.2 million of payments related to change of control and cash settlements of equity awards, $88.0 million for repayment of a portion of ATLS outstanding indebtedness and $11.0 million for reimbursement of certain transaction expenses. Approximately $4.5 million of the one-time cash payments and cash settlements of equity awards, which represent accelerated vesting of a portion of retained employees’ ATLS phantom units, were expensed at the acquisition date.

ATLS owned, directly and indirectly, 5,754,253 APL common units immediately prior to closing. Targa’s acquisition of ATLS resulted in Targa acquiring these common units (converted to 3,363,935 of our common units) valued at approximately $147.4 million (based on the $43.82 closing market price of our common units on the NYSE on February 27, 2015) and the right to receive the units’ one-time cash payment of approximately $7.3 million, which reduced the consolidated purchase price by approximately $154.7 million.

All outstanding ATLS equity awards, whether vested or unvested, were adjusted in connection with the Spin-Off on the terms and conditions set forth in an Employee Matters Agreement entered into by ATLS, ATLS GP and AEG on February 27, 2015. Following the Spin-Off-related adjustment and at the effective time of the ATLS merger, each outstanding ATLS option and ATLS phantom unit award, whether vested or unvested, held by a person who became an employee of AEG became fully vested (to the extent not vested) and was cancelled and converted into the right to receive the ATLS Merger Consideration in respect of each ATLS common unit underlying the ATLS option or phantom unit award (in the case of options, net of the applicable exercise price). Each outstanding vested ATLS option held by an employee of APL who became an employee of Targa in connection with the Atlas Transactions (a “Midstream Employee”) was cancelled and converted into the right to receive the ATLS Merger Consideration in respect of each ATLS common unit underlying the vested ATLS option, net of the applicable exercise price. Each outstanding unvested ATLS option and each outstanding ATLS phantom unit award held by a Midstream Employee was cancelled and converted into the right to receive (1) the ATLS Cash Consideration in respect of each ATLS common unit underlying such ATLS option or phantom unit award and (2) a TRC restricted stock unit award with respect to a number of shares of TRC Common Stock equal to the product of the ATLS Stock Consideration multiplied by the number of ATLS common units underlying such ATLS option or phantom unit award (in the case of options, net of the applicable exercise price).

In connection with the APL merger, each outstanding APL phantom unit award held by an employee of AEG became fully vested and was cancelled and converted into the right to receive the APL Merger Consideration in respect of each APL common unit underlying the APL phantom unit award. Each outstanding APL phantom unit award held by a Midstream Employee was cancelled and converted into the right to receive (1) the APL Cash Consideration in respect of each APL common unit underlying such APL phantom unit award and (2) a Partnership phantom unit award with respect to a number of our common units equal to the product of the APL Unit Consideration multiplied by the number of APL common units underlying such APL phantom unit award.

The acquired business contributed revenues of $1,065.7 million and a net loss of $1.0 million to us for the period from February 27, 2015 to September 30, 2015, and is reported in our Field Gathering and Processing segment. In 2015, we incurred $14.9 million of acquisition-related costs. These expenses are included in other expense in our Consolidated Statements of Operations for the nine months ended September 30, 2015.

Pro Forma Impact of Atlas Mergers on Consolidated Statements of Operations

The following summarized unaudited pro forma consolidated statement of operations information for the nine months ended September 30, 2015 and September 30, 2014 assumes that our acquisition of APL and Targa's acquisition of ATLS had occurred as of January 1, 2014. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed these acquisitions as of January 1, 2014, or that the results that will be attained in the future.

	Pro Forma Results for the Nine Months Ended	
	September 30, 2015	September 30, 2014
Revenues	$ 5,299.9	$ 8,659.5
Net income	178.1	462.1

The pro forma consolidated results of operations amounts have been calculated after applying our accounting policies, and making adjustments to:

- Reflect the change in amortization expense resulting from the difference between the historical balances of APL's intangible assets, net, and our preliminary estimate of the fair value of intangible assets acquired.

- Reflect the change in depreciation expense resulting from the difference between the historical balances of APL's property, plant and equipment, net, and our preliminary estimate of the fair value of property, plant and equipment acquired.

- Reflect the change in interest expense resulting from our financing activities directly related to the Atlas mergers as compared with APL's historical interest expense.

- Reflect the changes in stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership Long Term Incentive Plan ("LTIP") awards which were issued in connection with the acquisition to APL phantom unitholders who continue to provide service as Targa employees following the completion of the APL merger.

- Remove the results of operations attributable to APL businesses sold during the periods: (1) the May 2014 sale of APL's 20% interest in West Texas LPG Pipeline Limited Partnership and (2) the February 2015 transfer to Atlas Resource Partners, L.P. of 100% of APL's interest in gas gathering assets located in the Appalachian Basin of Tennessee.

- Exclude $14.9 million of acquisition-related costs incurred in 2015 from pro forma net income for the nine months ended September 30, 2015. Pro forma net income for the nine months ended September 30, 2014 was adjusted to include these charges.

- Conform to our accounting policy, we also adjusted APL's revenues to report plant sales of Y-grade at contractual net values rather than grossed up for transportation and fractionation deduction factors.

The following table summarizes the consideration transferred to acquire ATLS and APL, which are viewed together as a single integrated transaction for GAAP reporting purposes:

Fair Value of Consideration Transferred by Targa for ATLS:		
Cash paid, net of cash acquired (1)	$	745.7
Common shares of TRC		1,008.5
Replacement restricted stock units awarded (3)		5.2
Less: value of APL common units owned by ATLS		(147.4)
Total	$	1,612.0

Fair Value of Consideration Transferred by Targa for APL:		
Cash paid, net of cash acquired (2)	$	828.7
Common units of TRP		2,568.5
Replacement phantom units awarded (3)		15.0
Total	$	3,412.2
Total fair value of consideration transferred	$	5,024.2

(1) Targa acquired $5.5 million of cash.
(2) We acquired $35.3 million of cash.
(3) The fair value of consideration transferred in the form of replacement restricted stock unit awards and replacement phantom unit awards represent the allocation of the fair value of the awards to the pre-combination service period. The fair value of the awards associated with the post-combination service period will be recognized over the remaining service period of the award.

As of February 27, 2015, our preliminary fair value determination related to the Atlas mergers was as follows. The excess of the purchase price over the estimated fair value of net assets acquired was approximately $551.4 million, which was recorded as goodwill. This determination is based on our preliminary valuation and is subject to revisions pending the completion of the valuation and other adjustments.

Preliminary fair value determination:		**February 27, 2015**
Trade and other current receivables, net	$	181.1
Other current assets		24.5
Assets from risk management activities		102.1
Property, plant and equipment		4,703.1
Investments in unconsolidated affiliates		219.7
Intangible assets		1,199.0
Other long-term assets		5.6
Current liabilities		(257.5)
Long-term debt		(1,573.3)
Deferred income tax liabilities, net		(8.6)
Other long-term liabilities		(9.0)
Total identifiable net assets		4,586.7
Noncontrolling interest in subsidiaries		(113.4)
Current liabilities retained by Targa		(0.5)
Goodwill		551.4
	$	5,024.2

Our valuation of the acquired assets and liabilities is ongoing and may result in future measurement-period adjustments to these preliminary fair values. The fair values of property, plant and equipment, investments in unconsolidated affiliates, intangible assets representing customer contracts and customer relationships, deferred income taxes related to APL Arkoma, Inc., a taxable subsidiary acquired, and noncontrolling interest, which is calculated as a proportionate share of the fair value of the acquired joint ventures' net assets, are preliminary pending completion of final valuations. As a result, goodwill is also preliminary, as it has been recorded as the excess of the purchase price over the estimated fair value of net assets acquired.

During the three months ended June 30, 2015, we recorded measurement period adjustments to our preliminary acquisition date fair values due to the refinement of our valuation models, assumptions and inputs. As a result, the statement of operations for the three months ended March 31, 2015 was retrospectively adjusted for the impact of measurement-period adjustments to property, plant and equipment, intangible assets, and investment in unconsolidated affiliates. These adjustments resulted in a decrease in depreciation and amortization expense of $1.0 million, and an increase in equity earnings of $0.3 million from the amounts previously reported in our Form 10-Q for the quarter ended March 31, 2015.

During the three months ended September 30, 2015, we recorded additional measurement-period adjustments to our preliminary acquisition date fair values due to the refinement of our valuation models, assumptions and inputs. In accordance with the recent ASU 2015-16, we have recognized these measurement-period adjustments in the current reporting period, with the effect on the consolidated statements of operations resulting from the change to the provisional amounts calculated as if the acquisition had been completed at February 27, 2015. During the three months ended September 30, 2015, the acquisition date fair value of property, plant and equipment increased by $9.9 million, investments in unconsolidated affiliates increased by $5.5 million, intangible assets decreased by $5.0 million, current liabilities increased by $2.4 million, other assets decreased by $1.0 million, and other current assets decreased by $0.6 million, which resulted in a decrease in goodwill of $6.4 million. These adjustments resulted in increased revenues of $0.6 million, a reduction of operating expenses of $1.9 million, depreciation and amortization expense of $0.1 million and equity losses of $0.1 million recorded in the three months ended September 30, 2015, which under the prior accounting standard would have been reflected in previous reporting periods.

The preliminary valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 14 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

The preliminary determination of goodwill of $551.4 million is attributable to the workforce of the acquired business and the expected synergies with us and Targa. The goodwill is expected to be amortizable for tax purposes. The attribution of the goodwill to reporting units for the purpose of required future impairment assessments will be completed in conjunction with our finalization of the fair value determination.

The fair value of assets acquired includes trade receivables of $178.1 million. The gross amount due under contracts is $178.1 million, all of which is expected to be collectible. The fair value of assets acquired includes receivables of $3.0 million reported in current receivables and $4.5 million reported in other long-term assets related to a contractual settlement with a counterparty.

See Note 10-Debt Obligations for additional disclosures regarding related financing activities associated with the Atlas mergers.

Contingent Consideration

A liability arising from the contingent consideration for APL’s previous acquisition of a gas gathering system and related assets has been recognized at fair value. APL agreed to pay up to an additional $6.0 million if certain volumes are achieved on the acquired gathering system within a specified time period. The fair value of the remaining contingent payment is recorded within other long term liabilities on our Consolidated Balance Sheets. The range of the undiscounted amount that we could pay related to the remaining contingent payment is between $0.0 and $6.0 million. We finalized our acquisition analysis and modeling of this contingent liability during the three months ended June 30, 2015, which resulted in an acquisition date fair value of $4.2 million. Any future change in the fair value of this liability will be included in earnings.

Replacement Phantom Units

In connection with the Atlas mergers, we awarded replacement phantom units in accordance with and as required by the Atlas Merger Agreements to those APL employees who became Targa employees after the acquisition. The vesting dates and terms remained unchanged from the existing APL awards, and will vest over the remaining terms of the awards, which are either 25% per year over the original four year term or 33% per year over the original three year term.

Each replacement phantom unit will entitle the grantee to one common unit on the vesting date and is an equity-settled award. The replacement phantom units include distribution equivalent rights ("DERs"). When we declare and pay cash distributions, the holders of replacement phantom units will be entitled within 60 days to receive cash payment of DERs in an amount equal to the cash distributions the holders would have received if they were the holders of record on the record date of the number of our common units related to the replacement phantom units.

The fair value of the replacement phantom units was based on the closing price of our units at the close of trading on February 27, 2015. The fair value was allocated between the pre-acquisition and post-acquisition periods to determine the amount to be treated as purchase consideration and compensation expense, respectively. Compensation cost will be recognized in general and administrative expense over the remaining service period of each award.

Note 5 — Inventories

	September 30, 2015	December 31, 2014
Commodities	$ 138.4	$ 157.4
Materials and supplies	12.7	11.5
	$ 151.1	$ 168.9

Note 6 — Property, Plant and Equipment and Intangible Assets

	September 30, 2015	December 31, 2014	Estimated useful life (In Years)
Gathering systems	$ 6,187.7	$ 2,588.6	5 to 20
Processing and fractionation facilities	2,989.8	1,884.1	5 to 25
Terminaling and storage facilities	1,098.2	1,038.9	5 to 25
Transportation assets	439.5	359.0	10 to 25
Other property, plant and equipment	213.5	149.1	3 to 25
Land	108.5	95.6	-
Construction in progress	754.4	399.0	-
Property, plant and equipment	11,791.6	6,514.3	
Accumulated depreciation	(2,041.4)	(1,689.7)	
Property, plant and equipment, net	$ 9,750.2	$ 4,824.6	
Intangible assets	$ 1,880.6	$ 681.8	20
Accumulated amortization	(184.9)	(89.9)	
Intangible assets, net	$ 1,695.7	$ 591.9	

Intangible assets consist of customer contracts and customer relationships acquired in the Atlas mergers and our Badlands business acquisition. The fair values of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Key valuation assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate.

The fair values of intangible assets acquired in the Atlas mergers have been recorded at a preliminary value of $1,199.0 million pending completion of final valuations. For the purpose of our preparing the accompanying consolidated financial statements (which includes seven months of amortization of these intangible assets) we have amortized these intangible assets over a 20 year life using a straight-line method.

Amortization expense attributable to our intangible assets related to the Badlands acquisition is recorded using a method that closely reflects the cash flow pattern underlying their intangible asset valuation. The estimated annual amortization expense for intangible assets, including the preliminary Atlas valuation and straight-line treatment, is approximately $129.9 million, $148.1 million, $141.3 million, $127.6 million and $116.6 million for each of the years 2015 through 2019.

Note 7 — Asset Retirement Obligations

Our asset retirement obligations ("ARO") primarily relate to certain gas gathering pipelines and processing facilities, and are included in our Consolidated Balance Sheets as a component of other long-term liabilities. The changes in our ARO are as follows:

	Nine Months Ended September 30, 2015
Beginning of period	$ 56.8
Preliminary fair value of ARO acquired with the APL merger	4.0
Change in cash flow estimate	3.8
Accretion expense	3.9
End of period	$ 68.5

Note 8 — Investments in Unconsolidated Affiliates

Our unconsolidated investments consist of a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF") and three non-operated joint ventures in South Texas acquired in the Atlas merger; 75% interest in T2 LaSalle; 50% interest in T2 Eagle Ford; and 50% interest in T2 EF Co-Gen (together the "T2 Joint Ventures"). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting.

The following table shows the activity related to our investments in unconsolidated affiliates:

	Nine Months Ended September 30, 2015		
	GCF	T2 Joint Ventures	Total
Beginning of period	$ 50.2	$ -	$ 50.2
Preliminary fair value of T2 Joint Ventures acquired	-	219.7	219.7
Equity earnings (loss)	10.1	(11.2)	(1.1)
Cash distributions (1)	(10.7)	(0.5)	(11.2)
Cash calls for expansion projects	-	6.6	6.6
End of period	$ 49.6	$ 214.6	$ 264.2

(1) Includes $1.1 million in distributions received from GCF and T2 Joint Ventures in excess of our share of cumulative earnings for the nine months ended September 30, 2015. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

The recorded value of the T2 Joint Ventures is based on preliminary fair values at the date of acquisition which results in an excess fair value of $45.1 million over the book value of our partner capital accounts. This basis difference is attributable to depreciable tangible assets and is being amortized over the preliminary estimated useful lives of the underlying assets of 20 years on a straight-line basis and is included as a component of equity earnings. See Note 4 - Business Acquisitions for further information regarding the preliminary fair value determinations related to the Atlas mergers.

Note 9 — Accounts Payable and Accrued Liabilities

	September 30, 2015 (1)	December 31, 2014 (1)
Commodities	$ 416.5	$ 416.7
Other goods and services	100.5	108.9
Interest	68.0	37.3
Compensation and benefits	1.0	1.3
Income and other taxes	42.6	13.6
Other	21.9	14.9
	$ 650.5	$ 592.7

(1) We extinguish liabilities when the creditor receives our payment and we are relieved of our obligation (which for a check generally occurs when our bank honors that check). Liabilities to creditors to whom we have issued checks that remain outstanding totaled $27.8 million and $13.3 million at September 30, 2015 and December 31, 2014 and are included above in accounts payable and accrued liabilities.

Note 10 — Debt Obligations

	September 30, 2015	December 31, 2014
Current:		
Accounts receivable securitization facility, due December 2015	$ 135.5	$ 182.8
Long-term:		
Senior secured revolving credit facility, variable rate, due October 2017 (1)	435.0	-
Senior unsecured notes, 5% fixed rate, due January 2018	1,100.0	-
Senior unsecured notes, 4⅛% fixed rate, due November 2019	800.0	800.0
Senior unsecured notes, 6⅝% fixed rate, due October 2020 (2)	342.1	-
Unamortized premium	5.2	-
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(23.0)	(25.2)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	625.0
Senior unsecured notes, 6¾% fixed rate, due March 2024	600.0	-
Senior unsecured APL notes, 6⅝% fixed rate, due October 2020 (2)(3)	13.1	-
Unamortized premium	0.2	-
Senior unsecured APL notes, 4¾% fixed rate, due November 2021 (3)	6.5	-
Senior unsecured APL notes, 5⅞% fixed rate, due August 2023 (3)	48.1	-
Unamortized premium	0.6	-
Total long-term debt	5,336.4	2,783.4
Total debt	$ 5,471.9	$ 2,966.2
Irrevocable standby letters of credit outstanding	$ 11.2	$ 44.1

(1) As of September 30, 2015, availability under our $1.6 billion senior secured revolving credit facility was $1,153.8 million.
(2) In May 2015, we exchanged the TRP 6⅝% Senior Notes with the same economic terms to the holders of the 2020 APL Notes (as defined below) who validly tendered such notes for exchange to us.
(3) Senior unsecured notes issued by APL entities and acquired in the Atlas mergers. While we consolidate the debt acquired in the Atlas mergers, we do not guarantee the acquired debt of APL.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the nine months ended September 30, 2015:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.3%	2.2%
Accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

As of September 30, 2015, we were in compliance with the covenants contained in our various debt agreements.

Financing Activities

Revolving Credit Agreement

In February 2015, we entered into the First Amendment, Waiver and Incremental Commitment Agreement (the “First Amendment”) that amended our Second Amended and Restated Credit Agreement (the “Original Agreement”). The First Amendment increased available commitments to $1.6 billion from $1.2 billion while retaining our ability to request up to an additional $300.0 million in commitment increases. In addition, the First Amendment amends certain provisions of the Original Agreement and designates each of APL and its subsidiaries as an “Unrestricted Subsidiary.” We used proceeds from borrowings under the credit facility to fund some of the cash components of the APL merger, including $701.4 million for the repayments of the APL Revolver and $28.8 million related to change of control payments.

Senior Unsecured Notes

In January 2015, we and Targa Resources Partners Finance Corporation (collectively, the “Partnership Issuers”) issued $1.1 billion in aggregate principal amount of 5% Senior Notes due 2018 (the “5% Notes”). The 5% Notes resulted in approximately $1,089.8 million of net proceeds after costs, which were used with borrowings under our senior secured credit facility to fund the APL Notes Tender Offers and the Change of Control Offer (each as defined below). The 5% Notes are unsecured senior obligations that have substantially the same terms and covenants as our other senior notes.

In September 2015, the Partnership Issuers issued $600 million in aggregate principal amount of 6¾% Senior Notes due 2024 (the “6¾% Notes”). The 6¾% Notes resulted in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under our senior secured credit facility and for general partnership purposes. The 6¾% Notes are unsecured senior obligations that have substantially the same terms and covenants as our other senior notes.

April 2015 Shelf

In April 2015, we filed with the SEC a universal shelf registration statement that allows us to issue up to an aggregate of $1.0 billion of debt or equity securities (the "April 2015 Shelf"). The April 2015 Shelf expires in April 2018.

Accounts Receivable Securitization Facility

In August 2015, we reduced the maximum borrowing capacity of our accounts receivable securitization facility (the “Securitization Facility”) by $100.0 million to $200.0 million because we did not expect to fully utilize the former borrowing capacity in a lower commodity price environment. This reduction results in lower commitment fees on the unused portion of the Securitization Facility.

APL Merger Financing Activities

APL Senior Notes Tender Offers

In January 2015, we commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger, referred to as the APL Notes Tender Offers, which totaled $1.55 billion.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
			($ amounts in millions)				
6⅝% due 2020	$ 500.0	$ 140.1	$ 2.1	$ 3.7	$ 145.9	28.02%	$ 359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38%	6.5
5⅞% due 2023	650.0	601.9	8.7	2.6	613.2	92.60%	48.1
Total	$ 1,550.0	$ 1,135.5	$ 16.7	$ 11.6	$ 1,163.8		$ 414.5

In connection with the APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 4¾% Senior Notes due 2021 (the “2021 APL Notes”) and the 5⅞% Senior Notes due 2023 (the “2023 APL Notes”) of TPL and Targa Pipeline Finance Corporation (formerly known as Atlas Pipeline Finance Corporation) (together, the “APL Issuers”), became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 6⅝% Senior Notes due 2020 of the APL Issuers (the “2020 APL Notes”), we made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL Notes in advance of, and conditioned upon, the consummation of the APL merger. In March 2015, holders representing $4.8 million of the outstanding 2020 APL Notes tendered their notes requiring a payment of $5.0 million, which included the change of control premium and accrued interest.

Payments made under the APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities in the Consolidated Statements of Cash Flows.

Exchange Offer and Consent Solicitation

On April 13, 2015, the “Partnership Issuers commenced an offer to exchange (the “Exchange Offer”) any and all of the outstanding 2020 APL Notes, for an equal amount of new unsecured 6⅝% Senior Notes due 2020 issued by the Partnership Issuers (the “6⅝% Notes” or the “TRP 6⅝% Notes”). On April 27, 2015, we had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

In May 2015, upon the closing of the Exchange Offer, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes which were validly tendered for exchange. The related $5.6 million premium, resulting from acquisition date fair value accounting, will be amortized as an adjustment to interest expense over the remaining term of the TRP 6⅝% Notes. We recognized $0.5 million of costs associated with the Exchange Offer, reflected as a Loss from financing activities on our Consolidated Statements of Operations.

Note 11 — Partnership Units and Related Matters

Issuances of Common Units

As part of the Atlas merger, we issued 58,614,157 common units to former APL unitholders as consideration for the APL merger, of which 3,363,935 common units represented ATLS's common unit ownership in APL and were issued to Targa. Targa contributed $52.4 million to us to maintain its 2% general partner interest.

As of January 1, 2015 we had approximately $158.4 million of capacity available under our May 2014 Equity Distribution Agreement (the "May 2014 EDA"). In May 2015, we entered into an additional Equity Distribution Agreement under the April 2015 Shelf (the "May 2015 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. During the nine months ended September 30, 2015, we issued 7,377,380 common units under our EDAs, receiving proceeds of $316.1 million (net of commissions). As of September 30, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remain under the May 2014 and May 2015 EDAs. During the nine months ended September 30, 2015 Targa contributed $6.5 million to us to maintain its 2% general partner interest.

Subsequent Event-Preferred Units

In October 2015, under our automatic shelf registration statement filed in April 2013 and amended by a post-effective amendment filed in October 2015 (the "April 2013 Shelf"), we completed an offering of 4,400,000 Preferred Units at a price of $25.00 per unit. Pursuant to the exercise of the underwriters' overallotment option, we sold an additional 600,000 Preferred Units at a price of $25.00 per unit. We received net proceeds after costs of approximately $121.1 million. We used the net proceeds from this offering to reduce borrowings under our senior secured credit facility and for general partnership purposes. The Preferred Units are listed on the NYSE under the symbol "NGLS PRA."

Distributions on the Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on the Preferred Units will be payable out of amounts legally available therefor from and including the date of original issue to, but not including, November 1, 2020, at a rate equal to 9.0% per annum of the stated liquidation preference. On and after November 1, 2020, distributions on the Series A Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

The Preferred Units will, with respect to anticipated monthly distributions, rank:

- senior to our common units and to each other class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is not expressly made senior to or pari passu with the Preferred Units as to the payment of distributions;

- pari passu with any class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is not expressly made senior or subordinated to the Preferred Units as to the payment of distributions;

- junior to all of our existing and future indebtedness (including (i) indebtedness outstanding under our senior secured credit facility, (ii) our 5% Notes, our 4⅛% Senior Notes due 2019, our 6⅝% Notes, our 6⅞% Senior Notes due 2021, our 6⅜% Senior Notes due 2022, our 5¼% Senior Notes due 2023, our 4¼% Senior Notes due 2023 and our 6¾% Notes and (iii) indebtedness outstanding under our Securitization Facility and other liabilities with respect to assets available to satisfy claims against us; and

- junior to each other class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is expressly made senior to the Preferred Units as to the payment of distributions.

At any time on or after November 1, 2020, we may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we (or a third party with our prior written consent) may redeem the Preferred Units following certain changes of control, as described in our Partnership Agreement. If we do not (or a third party with our prior written consent does not) exercise this option, then the holders of the Preferred Units have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in our partnership agreement. If we exercise (or a third party with our prior written consent exercises) our redemption rights relating to any Preferred Units, the holders of those Preferred Units will not have the conversion right described above with respect to the Preferred Units called for redemption. Holders of Preferred Units have no voting rights except for certain exceptions set forth in our Partnership Agreement.

On October 20, 2015, we announced that the board of directors of our general partner declared a prorated monthly cash distribution of $0.10 per Preferred Unit. This cash distribution is the initial distribution payable on the Preferred Units for the period from October 15, 2015 through October 31, 2015, and will be paid November 16, 2015 on all outstanding Preferred Units to holders of record as of the close of business on October 30, 2015.

Distributions

We must distribute all of our available cash, after the preferred distribution, as defined in the Partnership Agreement, and as determined by the general partner, to common unitholders of record within 45 days after the end of each quarter. The following table details the distributions declared and/or paid by us for the nine months ended September 30, 2015:

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid or to be Paid	Common	Incentive Distribution Rights	2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
September 30, 2015	November 13, 2015	$ 152.5	$ 43.9(1)	$ 4.0	$ 200.4	$ 0.8250
June 30, 2015	August 14, 2015	152.5	43.9(1)	4.0	200.4	0.8250
March 31, 2015	May 15, 2015	148.3	41.7(1)	3.9	193.9	0.8200
December 31, 2014	February 13, 2015	96.3	38.4	2.7	137.4	0.8100

(1) Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDR's of $9.375 million were allocated to common unitholders in the first, second and third quarters of 2015. The IDR Giveback Amendment covers sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders in the following amounts: $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

Note 12 — Earnings per Limited Partner Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income	$ 53.3	$ 138.2	$ 184.4	$ 390.5
Less: Net income attributable to noncontrolling interests	4.8	9.9	17.3	30.9
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ 167.1	$ 359.6
Net income attributable to general partner	$ 44.9	$ 38.6	$ 132.0	$ 108.2
Net income attributable to limited partners	3.6	89.7	35.1	251.4
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ 167.1	$ 359.6
Weighted average units outstanding - basic	184.8	115.1	168.1	113.9
Net income available per limited partner unit - basic	$ 0.02	$ 0.78	$ 0.21	$ 2.21
Weighted average units outstanding	184.8	115.1	168.1	113.9
Dilutive effect of unvested stock awards	0.3	0.6	0.4	0.6
Weighted average units outstanding - diluted (1)	185.1	115.7	168.5	114.5
Net income available per limited partner unit - diluted	$ 0.02	$ 0.78	$ 0.21	$ 2.20

(1) For the three and nine months ended September 30, 2015, approximately 205,505 units and 187,303 units were excluded from the computation of diluted earnings per unit because the inclusion of such units would have been anti-dilutive.

Note 13 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity prices associated with a portion of our expected (i) natural gas equity volumes in our Field Gathering and Processing segment and (ii) NGL and condensate equity volumes predominately in our Field Gathering and Processing segment and the LOU business unit in our Coastal Gathering and Processing segment that result from percent-of-proceeds processing arrangements. These hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices. We have designated these derivative contracts as cash flow hedges for accounting purposes.

The hedges generally match the NGL product composition and the NGL delivery points of our physical equity volumes. Our natural gas hedges are a mixture of specific gas delivery points and Henry Hub. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations.

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

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $20.7 million and $52.2 million related to these novated contracts were received during the three and nine months ended September 30, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with no effect on results of operations.

The "off-market" nature of these acquired derivatives can introduce a degree of ineffectiveness for accounting purposes due to an embedded financing element representing the amount that would be paid or received as of the acquisition date to settle the derivative contract. The resulting ineffectiveness can either potentially disqualify the derivative contract in its entirety for hedge accounting or alternatively affect the amount of unrealized gains or losses on qualifying derivatives that can be deferred from inclusion in periodic net income. Certain novated APL crude options with a fair value of $7.7 million as of the acquisition date did not fall within the “highly effective” correlation range required to qualify as a hedging instrument for accounting purposes. These non-qualifying hedges resulted in $1.3 million and $1.0 million of mark-to-market gains for the three and nine months ended September 30, 2015. These crude oil options expired during 2015. Additionally, for the three and nine months ended September 30, 2015, we recorded $0.4 million and $1.3 million of ineffectiveness gains related to otherwise qualifying APL derivatives, primarily natural gas swaps.

At September 30, 2015, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2015	2016	2017	2018
Natural Gas	Swaps	MMBtu/d	163,456	79,399	23,082	-
Natural Gas	Basis Swaps	MMBtu/d	88,099	48,962	18,082	-
Natural Gas	Collars	MMBtu/d	15,400	22,900	22,900	9,486
NGL	Swaps	Bbl/d	4,268	2,674	1,078	208
NGL	Options/Collars	Bbl/d	920	920	920	32
Condensate	Swaps	Bbl/d	1,663	1,082	500	-
Condensate	Options/Collars	Bbl/d	1,605	790	790	101

We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and we record changes in fair value and cash settlements to revenues.

Our derivative contracts are subject to netting arrangements that permit our contracting subsidiaries to net cash settle offsetting asset and liability positions with the same counterparty. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements. The following schedules reflect the fair values of our derivative instruments and their location in our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

	Balance Sheet Location	Fair Value as of September 30, 2015 Derivative Assets	Fair Value as of September 30, 2015 Derivative Liabilities	Fair Value as of December 31, 2014 Derivative Assets	Fair Value as of December 31, 2014 Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 89.0	$ 2.1	$ 44.4	$ -
	Long-term	45.4	4.0	15.8	-
Total derivatives designated as hedging instruments		$ 134.4	$ 6.1	$ 60.2	$ -
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 3.3	$ 2.2	$ -	$ 5.2
Total derivatives not designated as hedging instruments		$ 3.3	$ 2.2	$ -	$ 5.2
Total current position		$ 92.3	$ 4.3	$ 44.4	$ 5.2
Total long-term position		45.4	4.0	15.8	-
Total derivatives		$ 137.7	$ 8.3	$ 60.2	$ 5.2

The pro forma impact of reporting derivatives in the Consolidated Balance Sheets on a net basis is as follows:

September 30, 2015	Gross Presentation Asset Position	Gross Presentation Liability Position	Pro Forma Net Presentation Asset Position	Pro Forma Net Presentation Liability Position
Current position				
Counterparties with offsetting position	$ 87.3	$ 4.3	$ 83.0	$ -
Counterparties without offsetting position - assets	5.0	-	5.0	-
Counterparties without offsetting position - liabilities	-	-	-	-
	92.3	4.3	88.0	-
Long-term position				
Counterparties with offsetting position	44.3	4.0	40.3	-
Counterparties without offsetting position - assets	1.1	-	1.1	-
Counterparties without offsetting position - liabilities	-	-	-	-
	45.4	4.0	41.4	-
Total derivatives				
Counterparties with offsetting position	131.6	8.3	123.3	-
Counterparties without offsetting position - assets	6.1	-	6.1	-
Counterparties without offsetting position - liabilities	-	-	-	-
	$ 137.7	$ 8.3	$ 129.4	$ -
December 31, 2014				
Current position				
Counterparties with offsetting position	$ 35.5	$ 4.4	$ 31.1	$ -
Counterparties without offsetting position - assets	8.9	-	8.9	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	44.4	5.2	40.0	0.8
Long-term position				
Counterparties with offsetting position	-	-	-	-
Counterparties without offsetting position - assets	15.8	-	15.8	-
Counterparties without offsetting position - liabilities	-	-	-	-
	15.8	-	15.8	-
Total derivatives				
Counterparties with offsetting position	35.5	4.4	31.1	-
Counterparties without offsetting position - assets	24.7	-	24.7	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	$ 60.2	$ 5.2	$ 55.8	$ 0.8

Our payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net asset of $129.4 million as of September 30, 2015. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented.

The following tables reflect amounts recorded in Other Comprehensive Income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

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,	
	2015	2014	2015	2014
Commodity contracts	$ 42.9	$ 14.2	$ 59.4	$ (4.5)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Interest expense, net	$ -	$ -	$ -	$ (2.4)
Revenues	16.7	(0.8)	41.1	(11.6)
	$ 16.7	$ (0.8)	$ 41.1	$ (14.0)

Our consolidated earnings are also affected by our use of the mark-to-market method of accounting for derivative 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 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 commodity price indices.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2015	2014	2015	2014
Commodity contracts	Revenue	$ (4.0)	$ (1.5)	$ (0.9)	$ (1.4)

The following table shows the deferred gains (losses) included in accumulated OCI, which will be reclassified into earnings through the end of 2018 as of the balance sheet date:

	September 30, 2015	December 31, 2014
Commodity hedges (1)	$ 78.5	$ 60.3

(1) Includes deferred net gains of $45.1 million as of September 30, 2015 related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 14 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

Note 14 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value in our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost in our Consolidated Balance Sheets. The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps and option contracts and fixed-price commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This financial position of these derivatives at September 30, 2015, a net asset position of $129.4 million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net asset of $105.3 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $152.0 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- The senior secured revolving credit facility (the "TRP Revolver") and the Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and

- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements 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 we can directly or indirectly observe 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 we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included in our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	September 30, 2015				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 137.7	$ 137.7	$ -	$ 133.1	4.6
Liabilities from commodity derivative contracts (1)	8.3	8.3	-	7.0	1.3
TPL contingent consideration (2)	4.2	4.2	-	-	4.2
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	92.8	92.8	-	-	-
Senior secured revolving credit facility	435.0	435.0	-	435.0	-
Senior unsecured notes	4,901.4	4,567.5	-	4,567.5	-
Accounts receivable securitization facility	135.5	135.5	-	135.5	-

(1) The fair value of our derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 13 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.
(2) See Note 4 – Business Acquisitions.

Additional Information Regarding Level 3 Fair Value Measurements Included in Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these natural gas swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

As of September 30, 2015, we had 23 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts (Asset)/Liability	Contingent Liability
Balance, December 31, 2014	$ (1.7)	$ -
TPL contingent consideration (see Note 4-Business Acquisitions)	-	4.2
New Level 3 instruments	(3.3)	-
Transfers out of Level 3	1.7	-
Balance, September 30, 2015	$ (3.3)	$ 4.2

For the nine months ended September 30, 2015, the Partnership transferred $1.7 million in derivative liabilities out of Level 3 and into Level 2. These transfers relate to long-term over-the-counter swaps for natural gas and NGL products with deliveries for which observable market prices were available.

Note 15 — Related Party Transactions - Targa

We do not have any employees. Targa provides operational, general and administrative and other services to us associated with our existing assets and assets acquired from third parties. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

Our Partnership Agreement governs the reimbursement of costs incurred by Targa on behalf of us. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than (1) costs attributable to Targa's status as a separate reporting company and (2) costs of Targa providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa monthly for cost allocations to the extent that Targa has made a cash outlay.

The following table summarizes transactions with Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Targa billings of payroll and related costs included in operating expense	$ 41.4	$ 33.1	$ 118.3	$ 94.6
Targa allocation of general and administrative expense	39.4	26.4	118.3	72.4
Cash distributions to Targa based on unit ownership	61.4	46.3	172.0	131.8
Cash contributions from Targa to maintain its 2% general partner ownership	1.4	1.8	60.1	5.2

Note 16 - Contingencies

Legal Proceedings

Atlas Unitholder Litigation

Between October and December 2014, five public unitholders of APL (the "APL Plaintiffs") filed putative class action lawsuits against APL, ATLS, APL GP, its managers, Targa, the Partnership, the general partner and MLP Merger Sub (the "APL Lawsuit Defendants"). These lawsuits are styled (a) *Michael Evnin v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania; (b) *William B. Federman Family Wealth Preservation Trust v. Atlas Pipeline Partners, L.P., et al.,* in the District Court of Tulsa County, Oklahoma (the "Tulsa Lawsuit"); (c) *Greenthal Living Trust U/A 01/26/88 v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania; (d) *Mike Welborn v. Atlas Pipeline Partners, L.P., et al.,* in the Court of Common Pleas for Allegheny County, Pennsylvania; and (e) *Irving Feldbaum v. Atlas Pipeline Partners, L.P., et al.,* in the Court of Common Pleas for Allegheny County, Pennsylvania, though the Tulsa Lawsuit has since been voluntarily dismissed. The *Evnin, Greenthal, Welborn and Feldbaum* lawsuits have been consolidated as *In re Atlas Pipeline Partners, L.P. Unitholder Litigation*, Case No. GD-14-019245, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated APL Lawsuit"). In October and November 2014, two public unitholders of ATLS (the "ATLS Plaintiffs" and, together with the APL Plaintiffs, the "Atlas Lawsuit Plaintiffs") filed putative class action lawsuits against ATLS, ATLS GP, its managers, Targa and GP Merger Sub (the "ATLS Lawsuit Defendants" and, together with the APL Lawsuit Defendants, the "Atlas Lawsuit Defendants"). These lawsuits are styled (a) *Rick Kane v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania and (b) *Jeffrey Ayers v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "ATLS Lawsuits"). The ATLS Lawsuits have been consolidated as *In re Atlas Energy, L.P. Unitholder Litigation*, Case No. GD-14-019658, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated ATLS Lawsuit" and, together with the Consolidated APL Lawsuit, the "Consolidated Atlas Lawsuits"), though the *Kane* lawsuit has since been voluntarily dismissed.

The Atlas Lawsuit Plaintiffs alleged a variety of causes of action challenging the Atlas mergers. Generally, the APL Plaintiffs alleged that (a) APL GP's managers have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, the Partnership, the general partner, MLP Merger Sub, APL, ATLS and APL GP have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The APL Plaintiffs further alleged that (a) the premium offered to APL's unitholders was inadequate, (b) APL agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire APL, and (c) APL GP's managers favored their self-interests over the interests of APL's unitholders. The APL Plaintiffs in the Consolidated APL Lawsuit also alleged that the registration statement filed on November 19, 2014 failed, among other things, to disclose allegedly material details concerning (i) Stifel, Nicolaus & Company, Incorporated's analysis of the Atlas mergers; (ii) APL and the Partnership's financial projections; and (iii) the background of the Atlas mergers. Generally, the ATLS Plaintiffs alleged that (a) ATLS GP's directors have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, GP Merger Sub, and ATLS have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The ATLS Plaintiffs further alleged that (a) the premium offered to the ATLS unitholders was inadequate, (b) ATLS agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire ATLS, (c) ATLS GP's directors favored their self-interests over the interests of the ATLS unitholders and (d) the registration statement failed to disclose allegedly material details concerning, among other things, (i) Wells Fargo Securities, LLC, Stifel, Nicolaus & Company, Incorporated, and Deutsche Bank Securities Inc.'s analyses of the Atlas mergers; (ii) the Partnership, Targa, APL, and ATLS' financial projections; and (iii) the background of the Atlas mergers.

Based on these allegations, the Atlas Lawsuit Plaintiffs sought to enjoin the Atlas Lawsuit Defendants from proceeding with or consummating the Atlas mergers unless and until APL and ATLS adopted and implemented processes to obtain the best possible terms for their respective unitholders. The Atlas Lawsuit Plaintiffs also sought rescission, damages, and attorneys' fees.

The parties to the Consolidated Atlas Lawsuits agreed to settle the Consolidated Atlas Lawsuits on February 9, 2015. In general, the settlements provide that in consideration for the dismissal of the Consolidated Atlas Lawsuits, ATLS and APL would provide supplemental disclosures regarding the Atlas mergers in a filing with the SEC on Form 8-K, which ATLS and APL did on February 11, 2015. The Atlas Lawsuit Defendants agreed to make such supplemental disclosures solely to avoid the uncertainty, risk, burden, and expense inherent in litigation and deny that any supplemental disclosure was or is required under any applicable rule, statute, regulation or law. The parties to the Consolidated Atlas Lawsuits have executed the settlement agreements and the settlement notices to the putative class members have been submitted to the Court for approval.

Environmental Proceeding

On August 22, 2014 and September 9, 2014, the Texas Commission on Environmental Quality ("TCEQ") issued Notices of Enforcement ("NOEs") to Targa Midstream Services LLC for alleged violations of air emissions regulations at the Mont Belvieu Fractionator relating to the operations of two regenerative thermal oxidizers during 2013 and 2014 and an unrelated discrete emissions event that occurred on May 29, 2014. On May 26, 2015, we signed an Agreed Order that will resolve all alleged violations stated in the NOEs. The Executive Director of the TCEQ signed the Agreed Order on September 11, 2015, and we anticipate the TCEQ Commissioners will approve the Agreed Order during their November 4, 2015 meeting. Under the Agreed Order, we are required to (1) pay an administrative penalty in the amount of $115,644; (2) pay $115,643 to fund certain supplemental environmental projects, and (3) comply with certain ordering provisions, including a requirement to install a flare gas recovery unit at the Mont Belvieu Fractionator within one year of the effective date of the Agreed Order.

We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business.

Note 17 — Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2015	2014
Cash:		
Interest paid, net of capitalized interest (1)	$ 147.6	$ 88.2
Income taxes paid, net of refunds	4.1	2.2
Non-cash Investing and Financing balance sheet movements:		
Debt additions and retirements related to exchange of TRP 6⅝% Notes for APL 6⅝% Notes	342.1	-
Deadstock commodity inventories transferred to property, plant and equipment	1.2	15.2
Reductions in Owner's Equity related to accrued distributions on unvested equity awards under share compensation arrangements	1.1	2.0
Receivables from equity issuances	-	0.4
Impact of capital expenditure accruals on property, plant and equipment	(57.2)	(40.6)
Transfers from materials and supplies inventory to property, plant and equipment	2.9	2.7
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	3.8	2.1
Non-cash balance sheet movements related to business acquisition: (see Note 4):		
Non-cash merger consideration - common units and replacement equity awards	$ 2,583.5	$ -
Special GP Interest	1,612.4	-
Current liabilities retained by Targa	(0.4)	-
Net non-cash balance sheet movements excluded from consolidated statements of cash flows	4,195.5	-
Net cash merger consideration included in investing activities	828.7	-
Total fair value of consideration transferred	$ 5,024.2	$ -

(1) Interest capitalized on major projects was $9.1 million and $14.3 million for the nine months ended September 30, 2015 and 2014.

Note 18 — Segment Information

We report our operations in two divisions: (i) 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 operating margin results of our commodity derivative activities are reported in Other.

Our 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 and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico

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

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for the LPG export market; and storing and terminaling refined petroleum products. These assets are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas and Lake Charles, Louisiana.

Our 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 our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG 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; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash-flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

We are reviewing our segment disclosures as a result of the merger and integration efforts related to the Atlas mergers.

Our reportable segment information is shown in the following tables:

	Three Months Ended September 30, 2015						
	Field Gathering and Processing	**Coastal Gathering and Processing**	**Logistics Assets**	**Marketing and Distribution**	**Other**	**Corporate and Eliminations**	**Total**
Revenues							
Sales of commodities	$ 419.5	$ 50.8	$ 31.3	$ 797.9	$ 21.8	$ -	$ 1,321.3
Fees from midstream services	108.4	8.9	82.4	111.1	-	-	310.8
	527.9	59.7	113.7	909.0	21.8	-	1,632.1
Intersegment revenues							
Sales of commodities	195.8	57.6	3.2	67.3	-	(323.9)	-
Fees from midstream services	2.4	-	64.6	5.4	-	(72.4)	-
	198.2	57.6	67.8	72.7	-	(396.3)	-
Revenues	$ 726.1	$ 117.3	$ 181.5	$ 981.7	$ 21.8	$ (396.3)	$ 1,632.1
Operating margin	$ 132.6	$ 7.9	$ 103.6	$ 60.2	$ 21.8	$ -	$ 326.1
Other financial information:							
Total assets (1)	$ 10,088.7	$ 346.2	$ 1,854.0	$ 543.8	$ 137.6	$ 352.9	$ 13,323.2
Goodwill (2)	$ 551.4	$ -	$ -	$ -	$ -	$ -	$ 551.4
Capital expenditures	$ 109.6	$ 5.5	$ 67.5	$ 0.9	$ -	$ 2.7	$ 186.2
Business acquisition	$ 5,024.2	$ -	$ -	$ -	$ -	$ -	$ 5,024.2

(1) Corporate assets at the Segment level primarily include investments in unconsolidated subsidiaries and debt issuance costs associated with our debt obligations.
(2) Total assets include goodwill. Goodwill has been preliminarily attributed to our Field Gathering and Processing segment.

Table of Contents

	Three Months Ended September 30, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 49.4	$ 83.4	$ 23.1	$ 1,855.6	$ (2.3)	$ -	$ 2,009.2
Fees from midstream services	49.4	8.0	75.5	146.2	-	-	279.1
	98.8	91.4	98.6	2,001.8	(2.3)	-	2,288.3
Intersegment revenues							
Sales of commodities	386.0	143.6	1.3	116.1	-	(647.0)	-
Fees from midstream services	1.7	-	85.9	10.1	-	(97.7)	-
	387.7	143.6	87.2	126.2	-	(744.7)	-
Revenues	$ 486.5	$ 235.0	$ 185.8	$ 2,128.0	$ (2.3)	$ (744.7)	$ 2,288.3
Operating margin	$ 98.0	$ 19.1	$ 118.6	$ 61.6	$ (2.3)	$ -	$ 295.0
Other financial information:							
Total assets	$ 3,359.0	$ 368.6	$ 1,650.2	$ 917.2	$ 6.7	$ 115.5	$ 6,417.2
Capital expenditures	$ 74.0	$ 2.3	$ 59.8	$ 4.6	$ -	$ 2.2	$ 142.9

	Nine Months Ended September 30, 2015						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 1,021.4	$ 156.1	$ 89.4	$ 2,792.0	$ 60.7	$ -	$ 4,119.6
Fees from midstream services	277.8	25.1	259.9	328.8	-	-	891.6
	1,299.2	181.2	349.3	3,120.8	60.7	-	5,011.2
Intersegment revenues							
Sales of commodities	624.1	178.0	6.4	214.4	-	(1,022.9)	-
Fees from midstream services	6.3	-	200.0	15.2	-	(221.5)	-
	630.4	178.0	206.4	229.6	-	(1,244.4)	-
Revenues	$ 1,929.6	$ 359.2	$ 555.7	$ 3,350.4	$ 60.7	$ (1,244.4)	$ 5,011.2
Operating margin	$ 349.9	$ 22.1	$ 341.7	$ 177.3	$ 60.7	$ -	$ 951.7
Other financial information:							
Total assets (1)	$ 10,088.7	$ 346.2	$ 1,854.0	$ 543.8	$ 137.6	$ 352.9	$ 13,323.2
Goodwill (2)	$ 551.4	$ -	$ -	$ -	$ -	$ -	$ 551.4
Capital expenditures	$ 345.2	$ 11.4	$ 199.6	$ 9.8	$ -	$ 5.0	$ 571.0
Business acquisition	$ 5,024.2	$ -	$ -	$ -	$ -	$ -	$ 5,024.2

(1) Corporate assets at the Segment level primarily include investments in unconsolidated subsidiaries and debt issuance costs associated with our debt obligations.

(2) Total assets include goodwill. Goodwill has been preliminarily attributed to our Field Gathering and Processing segment.

	Nine Months Ended September 30, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 158.0	$ 273.7	$ 73.0	$ 5,361.0	$ (12.4)	$ -	$ 5,853.3
Fees from midstream services	133.5	26.1	216.3	354.5	-	-	730.4
	291.5	299.8	289.3	5,715.5	(12.4)	-	6,583.7
Intersegment revenues							
Sales of commodities	1,168.2	484.0	2.7	383.6	-	(2,038.5)	-
Fees from midstream services	3.9	0.1	224.5	25.5	-	(254.0)	-
	1,172.1	484.1	227.2	409.1	-	(2,292.5)	-
Revenues	$ 1,463.6	$ 783.9	$ 516.5	$ 6,124.6	$ (12.4)	$ (2,292.5)	$ 6,583.7
Operating margin	$ 289.8	$ 67.0	$ 324.0	$ 179.5	$ (12.4)	$ -	$ 847.9
Other financial information:							
Total assets	$ 3,359.0	$ 368.6	$ 1,650.2	$ 917.2	$ 6.7	$ 115.5	$ 6,417.2
Capital expenditures	$ 301.4	$ 9.7	$ 195.9	$ 23.2	$ -	$ 3.6	$ 533.8

The following table shows our consolidated revenues by product and service for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Sales of commodities				
Natural gas	$ 456.1	$ 335.4	$ 1,201.6	$ 1,085.8
NGL	772.2	1,614.8	2,656.9	4,601.2
Condensate	40.4	38.6	113.1	108.7
Petroleum products	30.8	22.4	87.3	70.7
Derivative activities	21.8	(2.0)	60.7	(13.1)
	1,321.3	2,009.2	4,119.6	5,853.3
Fees from midstream services				
Fractionating and treating	55.7	55.3	160.1	153.5
Storage, terminaling, transportation and export	126.8	158.8	384.6	385.8
Gathering and processing	106.6	51.9	280.7	142.6
Other	21.7	13.1	66.2	48.5
	310.8	279.1	891.6	730.4
Total revenues	$ 1,632.1	$ 2,288.3	$ 5,011.2	$ 6,583.7

The following table shows a reconciliation of operating margin to net income for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Reconciliation of operating margin to net income:				
Operating margin	$ 326.1	$ 295.0	$ 951.7	$ 847.9
Depreciation and amortization expense	(165.8)	(87.5)	(448.3)	(252.8)
General and administrative expense	(42.9)	(40.4)	(130.1)	(115.3)
Interest expense, net	(64.1)	(36.0)	(177.2)	(104.1)
Other, net	(0.4)	8.4	(11.3)	18.5
Income tax (expense)/benefit	0.4	(1.3)	(0.4)	(3.7)
Net income	$ 53.3	$ 138.2	$ 184.4	$ 390.5

Note 19 — Buy-in Acquisition

On November 3, 2015 we and Targa announced that Targa will acquire all of our outstanding common units not already owned by Targa in an all stock-for-unit transaction at a ratio of 0.62 of Targa common shares per common unit of Targa Resources Partners. Following completion of the transaction, all of our outstanding common units will be owned by Targa and will no longer be publicly traded. The incentive distribution rights owned by Targa will be eliminated. All of our outstanding debt and our Series A preferred units will remain outstanding. No additional financing is required for the transaction.

The Board of Directors of Targa, the Conflicts Committee of the Board of Directors of our general partner and our Board have approved the merger agreement. Subject to customary approvals and conditions, including the expiration or termination of all waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act, the transaction is expected to close in the first quarter of 2016. The transaction is subject to the approval of our common unitholders and shareholders of Targa.

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, 2014 ("Annual Report"), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

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

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

Our Operations

We are a leading provider of midstream natural gas and NGL services in the United States, with a growing presence in crude oil gathering and petroleum terminaling. In connection with these business activities, we buy and sell natural gas, NGLs and NGL products, crude oil, condensate and refined products.

We are engaged in the business of:

- gathering, compressing, treating, processing and selling natural gas;
- storing, fractionating, treating, transporting and selling NGLs and NGL products, including services to LPG exporters;
- gathering, storing and terminaling crude oil; and
- storing, terminaling and selling refined petroleum products.

We report our operations in two divisions: (i) 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 operating margin results of our commodity derivative activities are reported in Other.

Our 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 and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for exporting LPGs; and storing and terminaling of refined petroleum products. These assets are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, in Lake Charles, Louisiana and in Tacoma, Washington.

Our 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 our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG 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; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results (including any hedge ineffectiveness) of the Partnership's commodity derivative activities included in operating margin and the mark-to-market gains/losses related to derivative contracts that were not designated as cash-flow hedges.

We are reviewing our segment disclosures as a result of the merger and integration efforts related to the Atlas mergers.

2015 Developments

Atlas Mergers

On February 27, 2015, (i) Targa completed the previously announced transactions contemplated by the ATLS Merger Agreement and (ii) Targa and the Partnership completed the previously announced transactions contemplated by the APL Merger Agreement. Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa, which we refer to as the ATLS merger. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership, which we refer to as the APL merger and, together with the ATLS merger, the Atlas mergers.

In connection with the Atlas mergers, APL changed its name to "Targa Pipeline Partners LP," which we refer to as TPL, and ATLS changed its name to "Targa Energy LP."

TPL is a provider of natural gas gathering, processing and treating services primarily in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in south Texas. The Atlas mergers add TPL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The results of TPL are reported in our Field Gathering and Processing segment.

Pursuant to the IDR Giveback Amendment entered into in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders in the first, second and third quarters of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders at the following amounts - $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

Logistics and Marketing Segment Expansion

Condensate Splitter or Alternate Project

On March 31, 2014, we announced the approval to construct a condensate splitter at our Channelview Terminal on the Houston Ship Channel. The condensate splitter was supported by a long-term fee-based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd. The initial project would have the capability to split approximately 35 MBbl/d of condensate into its various components, including naphtha, kerosene, gas oil, jet fuel and liquefied petroleum gas, and will provide segregated storage for the condensate and components.

Effective December 31, 2014, we and Noble agreed to modify the existing arrangements to build (i) a new terminal with significant storage capacity at Patriot; or (ii) a condensate splitter at Channelview with modified timing; or (iii) potentially both projects. We and Noble are evaluating these alternatives including final capabilities, capacities and capital costs. The modifications to the previous arrangements resulted in the receipt of a payment that was recognized monthly from January through August 15, 2015, and are expected to result in an enhanced economic benefit over the term of the arrangements. The project or projects are now expected to be completed in 2018 or later, depending on final scope and/or permitting.

Cedar Bayou Fractionator Train 5

In July 2014, we approved construction of a 100 MBbl/d fractionator at our 88%-owned Cedar Bayou Fractionator (“CBF”) in Mont Belvieu, Texas. The 100 MBbl/d expansion will be fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park on the Houston Ship Channel. All environmental and internal approvals required to commence construction of the expansion are in place, construction is underway and we expect completion of construction in mid-2016. Construction of the expansion will proceed without disruption to existing operations, and we estimate that total capital expenditures for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $385 million.

Field Gathering and Processing Segment Expansion

Eagle Ford Shale Natural Gas Processing Joint Venture

On October 5, 2015, we entered into joint venture agreements with Sanchez Energy Corporation (“Sanchez”) to construct a new 200 MMcf/d cryogenic natural gas processing plant in La Salle County, Texas (“La Salle County Plant”). We expect to invest approximately $125 million of growth capex related to the joint ventures, and assuming full contribution from Sanchez Energy, will have a 50% ownership interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We will hold all the transportation capacity on the pipeline and will pay the gathering joint venture fees for transportation.

The La Salle County Plant is expected to accommodate the growing production from Sanchez’s premier Eagle Ford Shale acreage position in Dimmit, La Salle and Webb Counties, Texas and from other third party producers. The plant and high pressure gathering lines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We will manage construction and operations of the plant and high pressure gathering lines, and the plant is expected to begin operations in early 2017. Prior to the plant being placed in service, we expect to benefit from Sanchez’s natural gas volumes that will be processed at our Silver Oak facilities in Bee County, Texas.

Badlands Little Missouri 3

In the first quarter of 2015, we completed the 40 MMcf/d Little Missouri 3 plant expansion in McKenzie County, North Dakota, that increased capacity to 90 MMcf/d.

Growth Investments in the Permian Basin

In April 2014, TPL announced plans to build a new plant and expand the gathering footprint of its WestTX system. This project includes the laying of a new high pressure gathering line into Martin and Andrews counties of Texas, as well as incremental compression and a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant, which is now expected to be completed during the first half of 2016.

Additionally, we have other growth capital expenditures in 2015 related to the continued build out of our gathering and processing systems and logistics capabilities.

In the current market environment, we are actively monitoring producer responses to changes in the commodity price environment and will continue to adjust our growth capital expenditure programs to meet expected producer requirements.

Financing Activities

In January 2015, the Partnership Issuers issued $1.1 billion in aggregate principal amount of 5% Notes. The $1,089.8 million of net proceeds after costs were used together with borrowings from the TRP Revolver to fund the APL Notes Tender Offers and the Change of Control Offer.

In April 2015, we filed with the SEC a universal shelf registration statement, the April 2015 Shelf, which allows us to issue up to an aggregate of $1.0 billion of debt or equity securities.

As of January 1, 2015 we had approximately $158.4 million of capacity available under our May 2014 EDA. In May 2015, we entered the May 2015 EDA, pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. During the nine months ended September 30, 2015, we issued 7,377,380 common units under our EDAs, receiving proceeds of $316.1 million (net of commissions). As of September 30, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remain under the May 2014 and May 2015 EDAs. During the nine months ended September 30, 2015 Targa contributed $6.5 million to us to maintain its 2% general partner interest.

In May 2015, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes, which were validly tendered for exchange. In connection therewith, the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

In August 2015, we reduced the maximum borrowing capacity of our Securitization Facility by $100.0 million to $200.0 million because we did not expect to fully utilize the former borrowing capacity in a lower commodity price environment. This reduction results in lower commitment fees on the unused portion of the Securitization Facility.

In September 2015, the Partnership Issuers issued $600.0 million in aggregate principal amount of 6¾% Notes resulting in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In October 2015, under our April 2013 Shelf, we completed an offering of 4,400,000 Preferred Units at a price of $25.00 per unit. Pursuant to the exercise of the underwriters' overallotment option, we sold an additional 600,000 Preferred Units at a price of $25.00 per unit. We received net proceeds after costs of approximately $121.1 million. We used the net proceeds from this offering to reduce borrowings under the TRP Revolver and for general partnership purposes. At the same time, we amended and restated our Partnership Agreement. See Note 11 - Partnership Units and Related Matters.

Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016, with early adoption permitted. We are currently evaluating the effect of the amendments for each of our less-than-wholly owned subsidiaries.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than revolving credit facilities) be presented in the consolidated balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update deals solely with financial statement display matters; recognition and measurement of debt issuance costs are unaffected. Unamortized debt issuance costs of $40.2 million and $29.9 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014. In August 2015, the FASB issued ASU 2015-15, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. The amendment clarifies ASU 2015-03 and provides that an entity may defer and present debt issuance costs for a line-of-credit or other revolving credit facility arrangement as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the arrangement. Unamortized debt issuance costs of $6.5 million and $7.6 million for revolving credit facilities were included in Other long-term assets on the Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014. We will continue to include debt issuance costs for our line-of-credit and revolving credit facility arrangements in Other long-term assets upon adoption of ASU 2015-03. We plan to adopt these standards as of December 31, 2015.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 303): Simplifying the Measurement of Inventory. Topic 303* currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This amendment has been adopted, with no impact on our consolidated financial statements or results of operations.

In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. The amendment defers the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) by one year. As a result of the amendment, Topic 606 is effective for the annual period beginning December 15, 2017, and for annual and interim periods thereafter, with early adoption permitted. Earlier adoption is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact of Topic 606 on our revenue recognition practices.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*. Topic 805 currently requires that adjustments to provisional amounts recorded in a business combination be recognized retrospectively as if the accounting had been completed at the acquisition date. The amendments in this update require that an acquirer recognize these measurement-period adjustments in the reporting period in which the adjustment amounts are determined, with the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments require disclosure of the amount recorded in current-period earnings that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for us in 2016, with early adoption permitted. We adopted the amendments on September 30, 2015 and have recognized the measurement-period adjustments for the Atlas mergers determined in the three months ended September 30, 2015 in current period earnings. See Note 4 for additional information regarding the nature and amount of the measurement-period adjustments.

How We Evaluate Our Operations

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

Our profitability is also impacted by fee-based revenues. Our growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, has increased the percentage of our revenues that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities.

Management uses a variety of financial measures and operational measurements to analyze our performance. These include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses, (3) capital expenditures and (4) the following non-GAAP measures: gross margin, operating margin, adjusted EBITDA and distributable cash flow.

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval. We have seen a substantial increase in our total capital spent since 2010 and currently have significant internal growth projects.

Gross Margin

We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program. We define Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate, crude oil and NGLs and (2) natural gas and crude oil gathering and service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas and crude oil purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

We define operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of our operations.

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

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

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

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

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 definitions of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

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

Adjusted EBITDA

We define Adjusted EBITDA as net income attributable to Targa Resources Partners LP before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments, including the cash impact of hedges acquired in the APL merger; non-cash compensation on TRP equity grants; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions and the noncontrolling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income attributable to Targa Resources Partners LP. Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities or GAAP net income. Adjusted EBITDA 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, thereby diminishing its utility.

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

Distributable Cash Flow

We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments, including the cash impact of hedges acquired in the APL merger; debt repurchases, redemptions, amendments, exchanges and early debt extinguishments; non-cash compensation on TRP equity grants; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions and asset disposals and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests.

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

Distributable cash flow is a non-GAAP financial measure. 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. It 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 comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the periods indicated:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$ 459.7	$ 407.8	$ 1,333.5	$ 1,171.5
Operating expenses	(133.6)	(112.8)	(381.8)	(323.6)
Operating margin	326.1	295.0	951.7	847.9
Depreciation and amortization expenses	(165.8)	(87.5)	(448.3)	(252.8)
General and administrative expenses	(42.9)	(40.4)	(130.1)	(115.3)
Interest expense, net	(64.1)	(36.0)	(177.2)	(104.1)
Income tax (expense) benefit	0.4	(1.3)	(0.4)	(3.7)
Gain on sale or disposition of assets	-	4.4	0.2	5.6
(Loss) from financing activities	(0.5)	-	(0.5)	-
Other, net	0.1	4.0	(11.0)	12.9
Net income	$ 53.3	$ 138.2	$ 184.4	$ 390.5

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(In millions)			
Reconciliation of Net Income to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ 167.1	$ 359.6
Interest expense, net	64.1	36.0	177.2	104.1
Income tax expense (benefit)	(0.4)	1.3	0.4	3.7
Depreciation and amortization expenses	165.8	87.5	448.3	252.8
Gain on sale or disposition of assets	-	(4.4)	(0.2)	(5.6)
Loss from financing activities	0.5	-	0.5	-
(Earnings) loss from unconsolidated affiliates (1)	1.6	(4.7)	1.1	(13.8)
Distributions from unconsolidated affiliates (1)	4.2	4.7	11.2	13.8
Compensation on TRP equity grants (1)	3.9	2.1	12.8	7.0
Transaction costs related to business acquisitions (1)	0.6	-	14.9	-
Risk management activities	21.8	1.5	46.0	0.9
Other	-	-	0.6	-
Noncontrolling interests adjustment (2)	(4.8)	(3.5)	(13.4)	(10.4)
Targa Resources Partners LP Adjusted EBITDA	$ 305.8	$ 248.8	$ 866.5	$ 712.1

(1) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.

(2) Noncontrolling interest portion of depreciation and amortization expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 215.5	$ 114.9	$ 737.8	$ 571.8
Net income attributable to noncontrolling interests	(4.8)	(9.9)	(17.3)	(30.9)
Interest expense	64.1	36.0	177.2	104.1
Non-cash interest expense, net (1)	(3.3)	(2.2)	(9.3)	(8.8)
(Earnings) loss from unconsolidated affiliates (2)	1.6	(4.7)	1.1	(13.8)
Distributions from unconsolidated affiliates (2)	4.2	4.7	11.2	13.8
Transaction costs related to business acquisitions (2)	0.6	-	14.9	-
Current income tax expense	0.2	0.9	0.7	2.6
Other (3)	(10.8)	(4.6)	(35.1)	(13.7)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	46.7	114.8	(157.9)	155.9
Accounts payable and other liabilities	(8.2)	(1.1)	143.2	(68.9)
Targa Resources Partners LP Adjusted EBITDA	$ 305.8	$ 248.8	$ 866.5	$ 712.1

(1) Includes amortization of debt issuance costs, discount and premium.
(2) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.
(3) Includes accretion expense associated with asset retirement obligations, noncontrolling interest portion of depreciation and amortization expenses and loss on financing activities.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)		(In millions)	
Reconciliation of net income to Distributable Cash flow:				
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ 167.1	$ 359.6
Depreciation and amortization expenses	165.8	87.5	448.3	252.8
Deferred income tax expense (benefit)	(0.6)	0.4	(0.3)	1.1
Non-cash interest expense, net (1)	3.3	2.2	9.3	8.8
Loss from financing activities	0.5	-	0.5	-
(Earnings) loss from unconsolidated affiliates (2)	1.6	(4.7)	1.1	(13.8)
Distributions from unconsolidated affiliates (2)	4.2	4.7	11.2	13.8
Compensation on TRP equity grants (2)	3.9	2.1	12.8	7.0
Gain on sale or disposition of assets	-	(4.4)	(0.2)	(5.6)
Risk management activities	21.8	1.5	46.0	0.9
Maintenance capital expenditures	(26.7)	(21.9)	(73.0)	(55.6)
Transactions costs related to business acquisitions (2)	0.6	-	14.9	-
Other (3)	(2.2)	(1.1)	(6.9)	(5.0)
Targa Resources Partners LP distributable cash flow	$ 220.7	$ 194.6	$ 630.8	$ 564.0

(1) Includes amortization of debt issuance costs, discount and premium.
(2) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.
(3) Includes the noncontrolling interests portion of maintenance capital expenditures, depreciation and amortization expenses.

Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	2015 vs. 2014		Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014	
	($ in millions, except operating statistics and price amounts)							
Revenues:								
Sales of commodities	$ 1,321.3	$ 2,009.2	$ (687.9)	34%	$ 4,119.6	$ 5,853.3	$ (1,733.7)	30%
Fees from midstream services	310.8	279.1	31.7	11%	891.6	730.4	161.2	22%
Total revenues	1,632.1	2,288.3	(656.2)	29%	5,011.2	6,583.7	(1,572.5)	24%
Product purchases	1,172.4	1,880.5	(708.1)	38%	3,677.7	5,412.2	(1,734.5)	32%
Gross margin (1)	459.7	407.8	51.9	13%	1,333.5	1,171.5	162.0	14%
Operating expenses	133.6	112.8	20.8	18%	381.8	323.6	58.2	18%
Operating margin (2)	326.1	295.0	31.1	11%	951.7	847.9	103.8	12%
Depreciation and amortization expenses	165.8	87.5	78.3	89%	448.3	252.8	195.5	77%
General and administrative expenses	42.9	40.4	2.5	6%	130.1	115.3	14.8	13%
Other operating (income) expenses	0.1	(4.3)	4.4	102%	0.6	(5.3)	5.9	111%
Income from operations	117.3	171.4	(54.1)	32%	372.7	485.1	(112.4)	23%
Interest expense, net	(64.1)	(36.0)	(28.1)	78%	(177.2)	(104.1)	(73.1)	70%
Equity earnings	(1.6)	4.7	(6.3)	134%	(1.1)	13.8	(14.9)	108%
Loss from financing activities	(0.5)	-	(0.5)	NM	(0.5)	-	(0.5)	NM
Other income (expense)	1.8	(0.6)	2.4	NM	(9.1)	(0.6)	(8.5)	NM
Income tax (expense) benefit	0.4	(1.3)	1.7	131%	(0.4)	(3.7)	3.3	89%
Net income	53.3	138.2	(84.9)	61%	184.4	390.5	(206.1)	53%
Less: Net income attributable to noncontrolling interests	4.8	9.9	(5.1)	52%	17.3	30.9	(13.6)	44%
Net income attributable to Targa Resources Partners LP	$ 48.5	$ 128.3	$ (79.8)	62%	$ 167.1	$ 359.6	$ (192.5)	54%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 305.8	$ 248.8	$ 57.0	23%	$ 866.5	$ 712.1	$ 154.4	22%
Distributable cash flow (4)	220.7	194.6	26.1	13%	630.8	564.0	66.8	12%
Capital expenditures	186.2	142.9	43.3	30%	571.0	533.8	37.2	7%
Operating statistics:								
Crude oil gathered, MBbl/d	108.9	99.2	9.7	10%	105.4	86.0	19.4	23%
Plant natural gas inlet, MMcf/d (5)(6)(7)	3,452.5	2,170.3	1,282.2	59%	3,163.2	2,111.2	1,052.0	50%
Gross NGL production, MBbl/d (7)	283.4	157.6	125.8	80%	255.7	152.2	103.5	68%
Export volumes, MBbl/d (8)	184.1	205.9	(21.8)	11%	180.0	160.5	19.5	12%
Natural gas sales, BBtu/d (6)(7)	1,932.3	923.7	1,008.6	109%	1,721.4	890.5	830.9	93%
NGL sales, MBbl/d (7)	499.2	441.6	57.6	13%	501.2	401.6	99.6	25%
Condensate sales, MBbl/d (7)	10.8	4.8	6.0	125%	9.5	4.4	5.1	116%

(1) Gross margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(2) Operating margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(3) Adjusted EBITDA is net income attributable to Targa Resources Partners LP before: interest, income taxes, depreciation and amortization, gains or losses on financing activities and asset disposals, risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL Merger, non-cash compensation on Partnership equity grants, transactions costs related to acquisitions, earnings/losses from unconsolidated affiliates net of distributions and the noncontrolling interest portion of depreciation and amortization expenses. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(4) Distributable cash flow is 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 risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger, financing activities, non-cash compensation on Partnership equity grants, transaction costs related to acquisitions, earnings/losses from unconsolidated affiliates net of distributions and asset disposals and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(7) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.
(8) Export volumes represent the quantity of NGL products delivered to third party customers at our Galena Park Marine terminal that are destined for international markets.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Revenues from commodity sales declined as the effect of significantly lower commodity prices ($1,749.6 million) exceeded the favorable impacts of inclusion of a full quarter of operations of TPL ($388.2 million), other volume increases ($648.3 million), and favorable hedge settlements ($21.8 million). Fee-based and other revenues increased due to the inclusion of TPL's fee revenue ($55.0 million), which were partially offset by lower export fees.

Offsetting lower commodity revenues was a commensurate reduction in product purchases due to significantly lower commodity costs ($1,050.9 million), which were partially offset by the inclusion of product purchases related to TPL's operations ($342.8 million).

The higher gross margin in 2015 was attributable to inclusion of TPL operations, increased throughput related to other system expansions in our Field Gathering and Processing segment, recognition of a renegotiated commercial contract and increased terminaling and storage fees, partially offset by lower fractionation and export margin in our Logistics and Marketing segments. Higher operating expenses are due to the inclusion of TPL's operations ($29.4 million), which more than offset the cost savings generated throughout our other operating areas. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

The increase in depreciation and amortization expenses reflects the impact of TPL, the planned increased amortization of the Badlands intangible assets and growth investments placed in service after June 2014, including the international export expansion project, continuing development at Badlands and other system expansions.

Higher general and administrative expenses is due to the inclusion of TPL general and administrative costs ($8.4 million), which was partially offset by general and administrative savings ($5.9 million), primarily from lower compensation and related costs.

The increase in interest expense primarily reflects higher borrowings attributable to the APL merger and lower capitalized interest associated with major capital projects compared to 2014.

Net income attributable to noncontrolling interests decreased due to lower earnings in 2015 that impacted our Cedar Bayou Fractionators, VESCO and Versado joint ventures, and the inclusion of losses from TPL's joint ventures.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Revenues declined as the effect of significantly lower commodity prices ($5,049.4 million) exceeded the favorable impacts of the inclusion of seven months of operations of TPL ($928.8 million), other volume increases ($2,321.9 million), and favorable hedge settlements ($60.7 million). Fee-based and other revenues increased due to the inclusion of TPL's operating results ($115.6 million), which were partially offset by lower export fees.

Offsetting lower commodity revenues was a commensurate reduction in product purchases due to significantly lower commodity costs ($2,550.1 million), which were partially offset by the inclusion of product purchases related to TPL's operations ($815.6 million).

The higher gross margin in 2015 was primarily attributable to increased Field Gathering and Processing throughput volumes primarily associated with the inclusion of TPL's operations and the recognition of a renegotiated commercial contract, partially offset by lower export margins and treating and reservation fees in our Logistics and Marketing segments. Higher operating expenses are due to the inclusion of TPL's operations ($69.4 million), which more than offset the cost savings generated throughout our other operating areas. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

Higher general and administrative expenses were primarily due to the inclusion of TPL general and administrative costs ($21.4 million), which partially offset other general and administrative savings ($6.6 million), primarily from lower compensation and related costs.

The nine months results were impacted by the same factors for depreciation and amortization expenses, interest expense, net and net income attributable to noncontrolling interests, as discussed above for the three month comparison of 2015 to 2014.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
			(In millions)			
Three Months Ended:						
September 30, 2015	$ 132.6	$ 7.9	$ 103.6	$ 60.2	$ 21.8	$ 326.1
September 30, 2014	98.0	19.1	118.6	61.6	(2.3)	295.0
Nine Months Ended:						
September 30, 2015	$ 349.9	$ 22.1	$ 341.7	$ 177.3	$ 60.7	$ 951.7
September 30, 2014	289.8	67.0	324.0	179.5	(12.4)	847.9

Table of Contents

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	2015 vs. 2014		Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$ 206.3	$ 145.6	$ 60.7	42%	$ 556.4	$ 428.7	$ 127.7	30%
Operating expenses	73.7	47.6	26.1	55%	206.5	138.9	67.6	49%
Operating margin	$ 132.6	$ 98.0	$ 34.6	35%	$ 349.9	$ 289.8	$ 60.1	21%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	240.2	207.0	33.2	16%	231.6	183.4	48.2	26%
WestTX (5)	460.2	-	460.2	NM	344.4	-	344.4	NM
Sand Hills	168.1	166.7	1.4	1%	166.1	164.4	1.7	1%
Versado	187.8	172.2	15.6	9%	182.3	165.9	16.4	10%
SouthTX (5)	139.1	-	139.1	NM	112.9	-	112.9	NM
North Texas (6)	339.1	361.8	(22.7)	6%	351.7	350.3	1.4	0%
SouthOK (5)	473.8	-	473.8	NM	378.2	-	378.2	NM
WestOK (5)	563.4	-	563.4	NM	458.6	-	458.6	NM
Badlands (7)	50.7	44.9	5.8	13%	46.6	39.2	7.4	19%
	2,622.4	952.6	1,669.8	175%	2,272.4	903.2	1,369.2	152%
Gross NGL production, MBbl/d (3)								
SAOU	28.6	25.9	2.7	10%	27.2	25.1	2.1	8%
WestTX (5)	53.6	-	53.6	NM	40.1	-	40.1	NM
Sand Hills	17.5	17.6	(0.1)	1%	17.6	18.1	(0.5)	3%
Versado	24.0	22.0	2.0	9%	23.5	20.8	2.7	13%
SouthTX (5)	13.7	-	13.7	NM	13.2	-	13.2	NM
North Texas	39.0	39.7	(0.7)	2%	40.2	36.9	3.3	9%
SouthOK (5)	30.3	-	30.3	NM	23.4	-	23.4	NM
WestOK (5)	27.9	-	27.9	NM	22.9	-	22.9	NM
Badlands	7.4	4.0	3.4	85%	6.3	3.5	2.8	80%
	242.0	109.2	132.8	122%	214.4	104.4	110.0	105%
Crude oil gathered, MBbl/d	108.9	99.2	9.7	10%	105.4	86.0	19.4	23%
Natural gas sales, BBtu/d (3)	1,518.6	478.7	1,039.9	217%	1,308.7	453.4	855.3	189%
NGL sales, MBbl/d	191.1	82.4	108.7	132%	167.2	79.5	87.7	110%
Condensate sales, MBbl/d	9.8	3.9	5.9	152%	8.5	3.6	4.9	136%
Average realized prices (8):								
Natural gas, $/MMBtu	2.48	3.80	(1.32)	35%	2.43	4.21	(1.78)	42%
NGL, $/gal	0.31	0.75	(0.44)	58%	0.35	0.79	(0.44)	55%
Condensate, $/Bbl	39.96	85.08	(45.12)	53%	43.31	88.17	(44.86)	51%

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter, including the volumes related to plants acquired in the APL merger.
(2) Plant natural gas inlet represents our undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.

(7) Badlands natural gas inlet represents the total wellhead gathered volume.
(8) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

The increase in gross margin was primarily due to the inclusion of the TPL volumes along with other volume increases partially offset by significantly lower commodity sales prices. The increases in plant inlet volumes were driven by system expansions and by increased producer activity which increased available supply across most of our areas of operation partially offset by reduced producer activity in North Texas. Higher natural gas and NGL sales reflect similar factors. Badlands crude oil and natural gas volumes increased significantly due to increased producer activity. The Little Missouri 3 plant which started commercial operations in January 2015 was a benefit to the gas volumes in the third quarter of 2015.

Despite cost reductions in most areas, higher operating expenses were primarily driven by the inclusion of TPL operating expenses and the commencement in operations of the Little Missouri 3 plant.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

The increase in gross margin was primarily due to the inclusion of the TPL volumes along with other volume increases partially offset by significantly lower commodity sales prices. The other increases in plant inlet volumes were driven by system expansions and by increased producer activity which increased available supply across our areas of operation partially offset by reduced producer activity and volumes in North Texas. The start-up of commercial operations in May 2014 at the Longhorn plant in North Texas, in June 2014 at the High Plains plant in SAOU and in January 2015 at the Little Missouri 3 plant in Badlands was a benefit to the nine-month period of 2015. Badlands crude oil and natural gas volumes increased significantly due to producer activities and plant and system expansion.

Despite cost reductions in most areas, higher operating expenses were primarily driven by the inclusion of TPL operating expenses and increased expenses associated with the commencement in operations of the Longhorn, High Plains and Little Missouri 3 plants.

Gross Operating Statistics Compared to Actual Reported

The table below provides a reconciliation between gross operating statistics and the actual reported operating statistics for the Field Gathering and Processing segment:

	Three Months Ended September 30, 2015			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU	240.2	100.0%	240.2	240.2
WestTX (4)(5)	632.1	72.8%	460.2	460.2
Sand Hills	168.1	100.0%	168.1	168.1
Versado (6)	187.8	63.0%	118.3	187.8
SouthTX (4)	139.1	100.0%	139.1	139.1
North Texas	339.1	100.0%	339.1	339.1
SouthOK (4)	473.8	Varies (7)	397.1	473.8
WestOK (4)	563.4	100.0%	563.4	563.4
Badlands (8)	50.7	100.0%	50.7	50.7
Total	2,794.3		2,476.2	2,622.4
Gross NGL production, MBbl/d (2)				
SAOU	28.6	100.0%	28.6	28.6
WestTX (4)(5)	73.6	72.8%	53.6	53.6
Sand Hills	17.5	100.0%	17.5	17.5
Versado	24.0	63.0%	15.1	24.0
SouthTX (4)	13.7	100.0%	13.7	13.7
North Texas	39.0	100.0%	39.0	39.0
SouthOK (4)	30.3	Varies (7)	27.0	30.3
WestOK (4)	27.9	100.0%	27.9	27.9
Badlands	7.4	100.0%	7.4	7.4
Total	262.0		229.8	242.0

(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 and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Operations acquired as part of the APL merger effective February 27, 2015.
(5) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(6) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(7) SouthOK includes the Centrahoma joint venture, of which TPL owns 60% and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(8) Badlands natural gas inlet represents the total wellhead gathered volume.

Coastal Gathering and Processing

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$ 17.7	$ 32.3	$ (14.6)	45%	$ 52.6	$ 102.2	$ (49.6)	49%
Operating expenses	9.8	13.2	(3.4)	26%	30.5	35.2	(4.7)	13%
Operating margin	$ 7.9	$ 19.1	$ (11.2)	59%	$ 22.1	$ 67.0	$ (44.9)	67%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU	177.0	293.1	(116.1)	40%	173.8	308.4	(134.6)	44%
VESCO	459.3	533.9	(74.6)	14%	438.9	514.9	(76.0)	15%
Other Coastal Straddles	193.8	390.9	(197.1)	50%	278.2	384.7	(106.5)	28%
	830.1	1,217.9	(387.8)	32%	890.9	1,208.0	(317.1)	26%
Gross NGL production, MBbl/d (3)								
LOU	7.1	9.2	(2.1)	23%	6.7	9.6	(2.9)	30%
VESCO	27.8	27.3	0.5	2%	25.7	26.3	(0.6)	2%
Other Coastal Straddles	6.5	11.9	(5.4)	45%	8.7	11.9	(3.2)	27%
	41.4	48.4	(7.0)	14%	41.1	47.8	(6.7)	14%
Natural gas sales, BBtu/d (3)	227.6	252.7	(25.1)	10%	231.4	266.5	(35.1)	13%
NGL sales, MBbl/d	31.4	40.8	(9.4)	23%	31.0	41.5	(10.5)	25%
Condensate sales, MBbl/d	0.8	0.7	0.1	14%	0.8	0.7	0.1	14%
Average realized prices:								
Natural gas, $/MMBtu	2.82	4.04	(1.22)	30%	2.85	4.58	(1.73)	38%
NGL, $/gal	0.38	0.80	(0.42)	53%	0.40	0.86	(0.46)	53%
Condensate, $/Bbl	49.13	102.88	(53.75)	52%	51.72	100.04	(48.32)	48%

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL sales prices, a less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to current market conditions and the decline of leaner off-system supply volumes.

Operating expenses decreased primarily due to reduced volumes and lower plant run-time due to current market conditions and reduced system and maintenance expenses at VESCO.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL sales prices, less favorable frac spread and lower throughput volumes, partially offset by new volumes at VESCO with higher GPM. The overall decrease in plant inlet volumes was largely attributable to current market conditions and the decline of leaner off-system supply volumes.

Operating expenses decreased primarily due to reduced volumes and lower plant run-time due to current market conditions.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended September 30,		2015 vs. 2014		Nine Months Ended September 30,		2015 vs. 2014	
	2015	2014			2015	2014		
	($ in millions, except operating statistics)							
Gross margin (1)	$ 153.1	$ 164.4	$ (11.3)	7%	$ 474.6	$ 449.1	$ 25.5	6%
Operating expenses (1)	49.5	45.8	3.7	8%	132.9	125.1	7.8	6%
Operating margin	$ 103.6	$ 118.6	$ (15.0)	13%	$ 341.7	$ 324.0	$ 17.7	5%
Operating statistics MBbl/d(2):								
Fractionation volumes (3)	344.6	368.6	(24.0)	7%	347.7	342.7	5.0	1%
LSNG treating volumes	23.8	24.8	(1.0)	4%	22.8	24.2	(1.4)	6%
Benzene treating volumes	23.8	24.8	(1.0)	4%	22.8	24.2	(1.4)	6%

(1) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the logistics segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(2) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Logistics Assets gross margin decreased primarily due to lower LPG export and fractionation margin, partially offset by a recognition of a portion of the renegotiated commercial arrangements related to our condensate splitter project and increased terminaling and storage activities. The lower export margin was partially due to LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, which averaged 184.1 MBbl/d in the third quarter of 2015 compared to 205.9 MBbl/d for the same period last year. Fractionation gross margin was impacted by a decrease in supply volume and by the variable effects of fuel and power, which are largely reflected in lower operating expenses (see footnote (1) above). Terminaling and storage volumes increased due to higher customer throughput.

Higher operating expenses were due to less favorable system product gains and higher maintenance, partially offset by lower fuel and power expense and lower export-related costs.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Logistics Assets gross margin increased primarily due to the recognition of the renegotiated commercial arrangements related to our condensate splitter project and increased terminaling and storage activities, partially offset by lower fractionation and LPG export gross margin. Terminaling and storage volumes increased due to higher customer throughput. Fractionation gross margin was impacted by the variable effects of fuel and power, which are largely reflected in lower operating expenses (see footnote (1) above) partially offset by an increase in supply volume. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 180.0 MBbl/d in 2015 compared to 160.5 MBbl/d for 2014.

Higher operating expenses were due to less favorable system product gains and higher maintenance, partially offset by lower fuel and power expense and lower export-related costs.

Marketing and Distribution

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	2015 vs. 2014		Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014	
	($ in millions)							
Gross margin	$ 70.2	$ 73.8	$ (3.6)	5%	$ 209.4	$ 217.2	$ (7.8)	4%
Operating expenses	10.0	12.2	(2.2)	18%	32.1	37.7	(5.6)	15%
Operating margin	$ 60.2	$ 61.6	$ (1.4)	2%	$ 177.3	$ 179.5	$ (2.2)	1%
Operating statistics (1):								
NGL sales, MBbl/d	401.1	444.3	(43.2)	10%	426.1	405.5	20.6	5%
Average realized prices:								
NGL realized price, $/gal	0.41	0.95	(0.54)	57%	0.47	1.00	(0.53)	53%

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

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Marketing and Distribution gross margin decreased primarily due to the lower LPG export volumes (which benefit both Logistics Assets and Marketing and Distribution segments), lower barge revenue and lower refinery LPG supply partially offset by higher marketing gains.

Operating expenses decreased primarily due to lower barge expense and truck expense.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Marketing and Distribution gross margin decreased primarily due to a lower price environment and the expiration and recognition of a contract settlement in 2014, lower barge revenue and lower refinery LPG supply. LPG export volumes (which benefit both Logistics Assets and Marketing and Distribution segments) were higher.

Operating expenses decreased primarily due to lower barge maintenance and lower railcar expense and truck expense.

Other

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	2015 vs. 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014
	($ in millions)					
Gross margin	$ 21.8	$ (2.3)	$ 24.1	$ 60.7	$ (12.4)	$ 73.1
Operating margin	$ 21.8	$ (2.3)	$ 24.1	$ 60.7	$ (12.4)	$ 73.1

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash-flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column. The primary purpose of our commodity risk management activities is to mitigate a portion of the impact of commodity prices on our operating cash flow. We have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because we are essentially forward-selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

The following table provides a breakdown of the change in Other operating margin:

	Three Months Ended September 30, 2015			Three Months Ended September 30, 2014			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	2015 vs. 2014
Natural Gas (BBtu)	16.2	$ 0.48	$ 7.7	6.1	$ (0.02)	$ (0.1)	$ 7.8
NGL (MMBbl)	0.6	14.72	8.5	7.3	0.07	0.5	8.0
Crude Oil (MMBbl)	0.2	33.50	6.7	0.2	(5.36)	(1.1)	7.8
Non-Hedge Accounting (3)			(1.7)			(1.6)	(0.1)
Ineffectiveness (4)			0.6			-	0.6
			$ 21.8			$ (2.3)	$ 24.1

	Nine Months Ended September 30, 2015			Nine Months Ended September 30, 2014			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	2015 vs. 2014
Natural Gas (BBtu)	35.0	$ 0.65	$ 22.6	15.9	$ (0.44)	$ (6.9)	$ 29.5
NGL (MMBbl)	62.4	0.29	18.1	15.9	0.04	0.7	17.4
Crude Oil (MMBbl)	0.7	19.71	13.8	0.7	(7.74)	(5.3)	19.1
Non-Hedge Accounting (3)			4.9			(1.0)	5.9
Ineffectiveness (4)			1.3			0.1	1.2
			$ 60.7			$ (12.4)	$ 73.1

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Price spread on Natural Gas volumes is $/MMBtu, NGL volumes is $/Bbl and Crude Oil volumes is $/Bbl.
(3) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(4) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $20.7 million and $52.2 million related to these novated contracts were received during the three and nine months ended September 30, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with no effect on results of operations.

Liquidity and Capital Resources

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

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under the TRP Revolver, borrowings under the Securitization Facility, the issuance of additional Preferred Units or common units and access to debt markets. The capital markets continue to experience volatility. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

Our liquidity as of September 30, 2015 was:

		September 30, 2015
		(In millions)
Cash on hand	$	92.8
Total commitments under the TRP Revolver		1,600.0
Total commitments under the Securitization Facility		135.5
		1,828.3
Less: Outstanding borrowings under the TRP Revolver		(435.0)
Outstanding borrowings under the Securitization Facility		(135.5)
Outstanding letters of credit under the TRP Revolver		(11.2)
Total liquidity	$	1,246.6

Other potential capital resources include:

- Our right to request an additional $300 million in commitment increases under the TRP Revolver, subject to the terms therein. The amended TRP Revolver matures on October 3, 2017.

- Our ability to issue debt or equity securities pursuant to shelf registration statements, including availability under the May 2015 EDA, which has approximately $835.6 million in remaining capacity as of October 15, 2015 and unlimited amounts under the shelf registration statement filed in April 2013.

A portion of our capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. While our credit ratings have improved over time, these letters of credit reflect our non-investment grade status, as assigned to us by Moody's and S&P. They also reflect certain counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

Debt Issuances

In January 2015, the Partnership Issuers issued $1.1 billion in aggregate principal amount of 5% Notes due 2018 resulting in approximately $1,089.8 million of net proceeds after costs, which were used together with borrowings from the TRP Revolver, to fund the APL Notes Tender Offers and the Change of Control Offer.

In September 2015, the Partnership Issuers issued $600.0 million in aggregate principal amount of 6¾% Notes due 2024 resulting in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

Amendment to Second Amended and Restated Credit Agreement

In February 2015, we amended our TRP Revolver to increase available commitments to $1.6 billion from $1.2 billion while retaining the right to request up to an additional $300.0 million in commitment increases (see Note 10 – Debt Obligations).

APL Senior Notes Tender Offers

In January 2015, we commenced cash tender offers referred to as the APL Notes Tender Offers, for any and all of the outstanding APL Senior Notes which totaled $1,550.0 million.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
			($ amounts in millions)				
6⅝% due 2020	$ 500.0	$ 140.1	$ 2.1	$ 3.7	$ 145.9	28.02%	$ 359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38%	6.5
5⅞% due 2023	650.0	601.9	8.7	2.6	613.2	92.60%	48.1
Total	$ 1,550.0	$ 1,135.5	$ 16.7	$ 11.6	$ 1,163.8		$ 414.5

In connection with the APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 2021 and 2023 APL Notes became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 2020 APL Notes, we made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL Notes in advance of, and conditioned upon, the consummation of the APL merger. In March 2015, holders representing $4.8 million of the outstanding 2020 APL Notes tendered their notes requiring a payment of $5.0 million, which included the change of control premium and accrued interest.

Payments made under the APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities in the Consolidated Statements of Cash Flows.

Exchange Offer and Consent Solicitation

In April 2015, we completed an offer to exchange, which we refer to as the Exchange Offer, for any and all of the outstanding 2020 APL Notes, which had an aggregate principal amount outstanding of $355.1 million and a $5.6 million premium established in our business combination accounting, for an equal amount of new unsecured TRP 6⅝% Notes. On April 27, 2015, we had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 APL Notes.

In May 2015, upon the closing of the Exchange Offer, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes, which were validly tendered for exchange.

Accounts Receivable Securitization Facility

In August 2015, we reduced the maximum borrowing capacity of the Securitization Facility by $100.0 million to $200.0 million because we did not expect to fully utilize the former borrowing capacity in a lower commodity price environment. This reduction results in lower commitment fees on the unused portion of the Securitization Facility.

Preferred Units Offering

In October 2015, under our April 2013 Shelf, we completed an offering of 5,000,000 Preferred Units at a price of $25.00 per unit. We received net proceeds of approximately $121.1 million after costs. We used the net proceeds from this offering to reduce borrowings under our senior secured credit facility and for general partnership purposes. At the same time, we amended and restated our Partnership Agreement. See Note 11-Partnership Units and Related Matters.

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes, NGL equity volumes and condensate equity volumes through 2018. See “Part II-Other Information, Item 3. Quantitative and Qualitative Disclosures about Market Risk.” The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Our risk management position has moved from a net asset position of $55.0 million at December 31, 2014 to a net asset position of $129.4 million at September 30, 2015. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. We account 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.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (1) our cash position; (2) liquids inventory levels and valuation, which we closely manage; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Our working capital increased $66.1 million excluding the decrease in current debt obligations. The major items contributing to this non-debt change were an increase in our net risk management working capital asset position due to changes in the forward prices of commodities and increased cash balances. Other factors included increased billing accruals related to the Badlands development projects, decreased payables to Parent due to the timing of annual compensation payments, and the inclusion of the working capital balance for TPL, offset by decreased commodity inventories due to falling prices and an increase in ad valorem tax accruals.

Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, borrowings available under the TRP Revolver and the Securitization Facility and proceeds from equity offerings and debt offerings should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and minimum quarterly cash distributions for at least the next twelve months.

Cash Flow

Cash Flow from Operating Activities

Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014
	(In millions)	
$ 737.8	$ 571.8	$ 166.0

Our Consolidated Statements of Cash Flows included in our historical consolidated financial statements employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting our net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented.

The following table displays our operating cash flows using the direct method as a supplement to the presentation in our financial statements:

	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014
	(In millions)		
Cash flows from operating activities:			
Cash received from customers	$ 5,039.0	$ 6,575.8	$ (1,536.8)
Cash received from (paid to) derivative counterparties	101.3	(12.2)	113.5
Cash outlays for:			
Product purchases	3,849.8	5,539.1	(1,689.3)
Operating expenses	265.8	265.0	0.8
General and administrative expenses	138.1	111.0	27.1
Cash distributions from equity investment (1)	(10.1)	(13.8)	3.7
Interest paid, net of amounts capitalized (2)	147.6	88.2	59.4
Income taxes paid, net of refunds	4.1	2.2	1.9
Other cash (receipts) payments	7.2	0.1	7.1
Net cash provided by operating activities	$ 737.8	$ 571.8	$ 166.0

(1) Excludes $1.1 million and $4.2 million included in investing activities for the nine months ended September 30, 2015 and 2014 related to distributions from GCF and T2 Joint Ventures that exceeded cumulative equity earnings.
(2) Net of capitalized interest paid of $9.1 million and $14.3 million included in investing activities for the nine months ended September 30, 2015 and 2014.

Lower commodity prices were the primary contributor to decreased cash collections and payments for product purchases in 2015 compared to 2014. Derivatives were a net inflow in 2015 versus a net outflow in 2014 reflecting lower commodity prices paid to counterparties compared to the fixed price we received on those derivative contracts. Higher cash outlay for general and administrative expenses in 2015 versus 2014 was mainly due to the addition of general and administrative costs for TPL. Higher cash interest paid was primarily due to higher debt borrowings. Other cash payments during 2015 reflect transaction costs related to the Atlas mergers.

Cash Flow from Investing Activities

Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014
(In millions)		
$ (1,462.5)	$ (561.2)	$ (901.3)

The increase in net cash used in investing activities for 2015 compared to 2014 was primarily due to the $828.7 million cash outlays for the Atlas mergers, along with a $53.6 million increase in capital expenditures.

Cash Flow from Financing Activities

Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 vs. 2014
(In millions)		
$ 745.2	$ 4.3	$ 740.9

The increase in net cash provided by financing activities for 2015 compared to 2014 was primarily due to the Atlas mergers, including the issuance of senior notes ($1.1 billion), net borrowings under our debt facilities ($819.4 million) and payments to settle the tender for APL's senior notes ($1,168.8 million). During the third quarter of 2015, we had additional note issuances of $600.0 million and net repayments under our debt facilities of $431.7 million. Distributions to unitholders increased in 2015 ($169.8 million).

Distributions to our Unitholders

We intend to make monthly cash distributions to the holders of our Preferred Units. Distributions on the Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on the Preferred Units will be payable out of amounts legally available therefor from and including the date of original issue to, but not including, November 1, 2020, at a rate equal to 9.0% per annum of the stated liquidation preference. On and after November 1, 2020, distributions on the Preferred Units will accumulate at an annual floating rate equal to the one month LIBOR plus a spread of 7.71%.

On October 20, 2015, we announced that the board of directors of our general partner declared a prorated monthly cash distribution of $0.10 per Preferred Unit. This cash distribution is the initial distribution payable on the Preferred Units for the period from October 15, 2015 through October 31, 2015, and will be paid November 16, 2015 on all outstanding Preferred Units to holders of record as of the close of business on October 30, 2015.

We distribute all available cash, after the preferred distribution, from our operating surplus. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Notes 10 and 11 of the "Consolidated Financial Statements" included in this Quarterly Report.

We intend to make cash distributions to our limited partners and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of September 30, 2015, such annual minimum amount would have been approximately $254.6 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate. The quarterly distribution per limited partner unit to be paid in November 2015 for the third quarter of 2015 is $0.8250 per limited partner unit.

The following table details the distributions declared and/or paid during the nine months ended September 30, 2015:

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid or to be Paid	Common	Incentive Distribution Rights	2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
September 30, 2015	November 13, 2015	$ 152.5	$ 43.9 (1)	$ 4.0	$ 200.4	$ 0.8250
June 30, 2015	August 14, 2015	152.5	43.9 (1)	4.0	200.4	0.8250
March 31, 2015	May 15, 2015	148.3	41.7 (1)	3.9	193.9	0.8200
December 31, 2014	February 13, 2015	96.3	38.4	2.7	137.4	0.8100

(1) Pursuant to the IDR Giveback Amendment entered into in conjunction with the Atlas mergers, IDR's of $9.375 million were allocated to common unitholders in the first, second and third quarters of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and will result in reallocation of IDR payments to common unitholders at the following amounts - $9.375 million per quarter for 2015, $6.25 million per quarter for 2016, $2.5 million per quarter for 2017 and $1.25 million per quarter for 2018.

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as expansion expenditures, which include business acquisitions, or maintenance expenditures. Expansion capital 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. Maintenance capital 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 are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

	Nine Months Ended September 30,	
	2015	2014
Capital expenditures :	(In millions)	
Consideration for business acquisitions	$ 5,024.2	$ -
Non-cash consideration APL merger	(2,583.1)	-
Non-cash Targa contribution, Special General Partner interest (1)	(1,612.4)	-
Cash consideration for business acquisitions, net of cash acquired	828.7	-
Expansion	497.9	478.2
Maintenance	73.1	55.6
Gross capital expenditures	571.0	533.8
Transfers from materials and supplies inventory to property, plant and equipment	(2.9)	(2.7)
Decrease (increase) in capital project payables and accruals	57.2	40.6
Cash outlays for capital projects	625.3	571.7
Targa cash consideration, ATLS merger	745.6	-
	$ 2,199.6	$ 571.7

(1) Includes the Special GP Interest and non-cash value of consideration (see Note 4 – Business Acquisitions of the "Consolidated Financial Statements").

We estimate that our total growth capital expenditures, on a gross basis, will be approximately $700.0 million to $800.0 million for 2015 and approximately $600 million for 2016, and maintenance capital expenditures net to our interest will be approximately $100 million to $110 million for 2015 and 2016. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. We expect to fund future capital expenditures with funds generated from our operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt securities.

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. We have updated our accounting policies during the nine months ended September 30, 2015 in Note 3 of the "Consolidated Financial Statements" in this Quarterly Report to include our accounting policy for goodwill.

Based on our analysis of the acquired assets and liabilities and the preliminary data provided by our valuation consultants, we have recorded goodwill in connection with the Atlas mergers on February 27, 2015. The preliminary value may be adjusted pending completion of the final valuation and we are evaluating the allocation of goodwill to the reporting unit level. Goodwill is subject to testing for impairment at the reporting unit level at least annually, as well as whenever events or changes in circumstances indicate it is more likely than not the fair value of an affected reporting unit is less than its carrying amount.

Recoverability of Long-lived Assets

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We routinely meet with our commercial management to assess commodity pricing, the outlook for volumes and the expected impact on each of our facilities. When an impairment trigger event is identified we test the long lived asset (asset group) for recoverability. We consider all relevant scenarios for the facilities including alternate utilization, relocation, and salvage value. Further, we periodically reassess the facilities' remaining depreciable lives and shorten them when appropriate in order to remain in line with their expected remaining economic lives.

Off-Balance Sheet Arrangements

As of September 30, 2015, there were $25.4 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety, and (iii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Contractual Obligations

As of September 30, 2015, there have been no significant changes in the contractual obligations as presented in our 2014 Form 10-K, except for those acquired in the Atlas mergers, which were previously disclosed in our Form 10-Q for the quarter ended March 31, 2015.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers.

Commodity Price Risk

A significant portion of our revenues is derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce volatility in our operating cash flows due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of September 30, 2015, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations, as well as in the LOU portion of the Coastal Gathering and Processing Operations, that result from percent-of-proceeds processing arrangements by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, in which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

When entering into new hedges, we intend to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. The natural gas and NGL hedges’ fair values are based on published index prices for delivery at various locations, which closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

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

For all periods presented, we have entered into hedging arrangements for a portion of our forecasted equity volumes. During the three months ended September 30, 2015 and 2014 our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $21.8 million and $(2.3) million. During the nine months ended September 30, 2015 and 2014, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $60.7 million and $(12.4) million.

Our risk management position has moved from a net asset position of $55.0 million at December 31, 2014 to a net asset position of $129.4 million at September 30, 2015. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. We account 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.

As of September 30, 2015, we had the following derivative instruments designated as hedging instruments that will settle during the years ending below:

Natural Gas

Instrument Type	Index	Price $/MMBtu		MMBtu/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	4.05		36,236	-	-	-	$ 4.1
Swap	IF-WAHA	3.94		-	19,436	-	-	7.9
Swap	IF-WAHA	3.69		-	-	5,000	-	1.4
Total Swaps				36,236	19,436	5,000	-	
Swap	IF-PB	4.01		14,576	-	-	-	2.0
Swap	IF-PB	3.99		-	7,608	-	-	3.7
Total Swaps				14,576	7,608	-	-	
Swap	IF-NGPL MC	3.84		4,739	-	-	-	0.6
Swap	IF-NGPL MC	3.93		-	3,456	-	-	1.6
Total Swaps				4,739	3,456	-	-	-
						-	-	
Swap	NG-NYMEX	4.14		71,318	-	-		10.1
Swap	NG-NYMEX	4.15		-	37,705	-		18.5
Swap	NG-NYMEX	4.11		-	-	18,082	-	7.0
Total Swaps				71,318	37,705	18,082	-	
Total Natural Gas Swaps				126,869	68,205	23,082	-	
								56.9
		Put Price	Call Price					
Collar	IF-WAHA	2.85	3.47	-	7,500	-	-	0.8
Collar	IF-WAHA	3.00	3.67	-	-	7,500	-	0.7
Collar	IF-WAHA	3.25	4.20	-	-	-	1,849	0.2
Total Collars				-	7,500	7,500	1,849	
Collar	IF-PB	2.55	3.10	15,400	-	-	-	0.2
Collar	IF-PB	2.65	3.31	-	15,400	-	-	1.1
Collar	IF-PB	2.80	3.50			15,400		1.0
Collar	IF-PB	3.00	3.65	-	-	-	7,637	0.6
Total Collars				15,400	15,400	15,400	7,637	
Total Natural Gas Collars				15,400	22,900	22,900	9,486	
								$ 61.5

NGL

Instrument Type	Index	Price $/Gal		Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	C2 OPIS-MB	0.20		420	-	-	-	$ -
Swap	C2 OPIS-MB	0.21		-	420	-	-	0.1
Swap	C2 OPIS-MB	0.23		-	-	420	-	0.1
Swap	C2 OPIS-MB	0.26		-	-	-	208	0.1
Total Swaps				420	420	420	208	
Swap	C3 OPIS-MB	1.03		3,522	-	-	-	$ 7.6
Swap	C3 OPIS-MB	1.03		-	2,254	-	-	19.2
Swap	C3 OPIS-MB	1.04		-	-	658	-	5.5
Total Swaps				3,522	2,254	658	-	
Swap	C5 OPIS-MB	2.00		326	-	-	-	1.3
Total NGL Swaps				4,268	2,674	1,078	208	
		Put Price	Call Price					
Collar	C2 OPIS-MB	0.170	0.190	410	-	-	-	-
Collar	C2 OPIS-MB	0.200	0.235	-	410	-	-	0.1
Collar	C2 OPIS-MB	0.240	0.290	-	-	410	-	0.2
				410	410	410	-	
		Put Price	Call Price					
Collar	C3 OPIS-MB	0.550	0.668	380	-	-	-	0.1
Collar	C3 OPIS-MB	0.560	0.680	-	380	-	-	0.7
Collar	C3 OPIS-MB	0.570	0.686	-	-	380	-	0.7
				380	380	380	-	
		Put Price	Call Price					
Collar	C5 OPIS-MB	1.200	1.410	130	-	-	-	0.1
Collar	C5 OPIS-MB	1.200	1.390	-	130	-	-	0.5
Collar	C5 OPIS-MB	1.210	1.415	-	-	130	-	0.5
Collar	C5 OPIS-MB	1.230	1.385	-	-	-	32	0.1
				130	130	130	32	
Total Collars				920	920	920	32	
Total				5,188	3,594	1,998	240	
								$ 36.9

Condensate

Instrument Type	Index	Price $/Bbl		Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	NY-WTI	81.56		1,663	-	-	-	$ 5.5
Swap	NY-WTI	81.13		-	1,082	-	-	12.6
Swap	NY-WTI	79.70		-	-	500	-	4.8
Total Swaps				1,663	1,082	500	-	
		Put Price	Call Price					
Collar	NY-WTI	53.19	66.03	790	-	-	-	0.6
Collar	NY-WTI	57.08	67.97	-	790	-	-	2.8
Collar	NY-WTI	58.56	69.95	-	-	790	-	2.5
Collar	NY-WTI	60.00	71.60				101	0.4
Total Collars				790	790	790	101	
Total				2,453	1,872	1,290	101	
								$ 29.2

As of September 30, 2015 we had the following derivative instruments that are not designated as hedges and are marked-to-market

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2015	2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	2.94	29,174	11,194	-	-	$ -
Basis Swap	various	(0.19)	88,099	48,962	18,082	-	(1.3)
Transport (1)	various	0.33	7,413	-	-	-	(0.1)
							$ (1.4)

Condensate

Instrument Type	Index	Price $/Bbl	Bbl/d 2015	2016	2017	2018	Fair Value (In millions)
Put Option (1)	NY-WTI	88.15	815	-	-	-	$ 3.2

(1) Represents short-term hedges that expire in the fourth quarter of 2015.

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls). For derivative instruments not designated as cash-flow hedges these contracts are marked-to-market and recorded in revenues.

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option-pricing model for options based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 14 of the "Consolidated Financial Statements" in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of September 30, 2015, we do not have any interest rate hedges. However, we may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRP Revolver and the Securitization Facility will also increase. As of September 30, 2015, we had $570.5 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable debt would impact our annual interest expense by $5.7 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with all of our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $8.3 million as of September 30, 2015. The range of losses attributable to our individual counterparties would be between less than $0.1 million and $48.6 million, depending on the counterparty in default.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have an established policy and various procedures to manage our credit exposure risk, including initial and subsequent credit risk analyses, credit limits and terms and credit enhancements when necessary. We use credit enhancements including (but not limited to) letters of credit, prepayments, parental guarantees and rights of offset to limit credit risk to ensure that our established credit criteria are followed and financial loss is mitigated or minimized.

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $6.2 million in the year of the assessment.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

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, 2015, 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

On February 27, 2015, we completed our acquisition of APL and ATLS. Except for these acquisitions, which we have excluded from our assessment of the effectiveness of our internal controls over financial reporting for 2015, 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, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 16 – 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 "Part I—Item 1A. Risk Factors" in our 2014 Annual Report, except for the additional risk factor discussed below. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement and modify or revoke existing rulings, including ours.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Our Partnership Agreement provides that if a law is enacted, or existing law is modified or interpreted in a manner, that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

Recent Sales of Unregistered Securities

None.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers

Period	Total number of units withheld (1)	Average price per share	Total number of units purchased as part of publicly announced plans	Maximum number of units that may yet be purchased under the plan
July 1, 2015 - July 31, 2015	80,562	38.89	-	-
August 1, 2015 - August 31, 2015	4,367	34.50	-	-
September 1, 2015 - September 30, 2015	285	31.32	-	-

(1) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers, directors and key employees that arose upon the lapse of restrictions on the equity-settled performance units.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information

Partnership Tax Matters

On May 19, 2014, Targa Resources GP LLC received a Notice of Beginning of Administrative Proceeding (“NBAP”) relating to the Internal Revenue Service’s (“IRS”) audit of TRP’s 2011 Form 1065 federal tax return. Under IRS regulations, Targa was required to communicate the NBAP to all limited partners who hold less than 1% of our outstanding units (“Non-Notice Partners”) within 75 days of receipt of the NBAP. To provide the NBAP to its Non-Notice Partners, Targa Resources GP LLC has posted the NBAP on its website under Tax Matters.

On April 9, 2015, Targa received a No Adjustments Letter relating to the IRS audit of TRP’s 2011 Form 1065 federal tax return. There were no adjustments proposed by the IRS for TRP’s 2011 Form 1065 federal tax return.

Item 6. Exhibits

Number	Description
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Second 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 October 15, 2015 (File No. 001-33303)).
3.4	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Indenture, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 15, 2015 (File No. 001-33303)).
4.2	Registration Rights Agreement, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed September 15, 2015 (File No. 001-33303)).
4.3	Specimen Unit Certificate for the Series A Preferred Units (attached as Exhibit B to the Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP and incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
10.1	Purchase Agreement dated as of September 9, 2015 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on 8-K filed September 15, 2015 (File No. 001-33303)).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
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
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith

\+ Management contract or compensatory plan or arrangement

SIGNATURES

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: November 3, 2015

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

Exhibit 12.1

Targa Resources Partners LP
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,					Nine Months Ended September 30,	
	2014	2013	2012	2011	2010	2015	2014
	(In millions)						
Pre-tax income from continuing operations	$ 509.9	$ 261.5	$ 207.4	$ 249.8	$ 138.0	$ 184.8	$ 394.2
Fixed charges:							
Interest expense and amortization of debt issuance costs	143.8	131.0	116.8	107.7	110.9	177.2	104.1
Capitalized interest	16.1	28.0	13.6	3.4	1.3	9.1	14.3
Operating lease payments	8.2	7.8	5.4	4.7	4.6	9.9	6.4
Total fixed charges	168.1	166.8	135.8	115.8	116.8	196.2	124.8
Amortization of capitalized interest	2.8	1.7	0.7	0.2	0.1	0.8	0.9
Equity earnings in unconsolidated affiliates	(18.0)	(14.8)	(1.9)	(8.8)	(5.4)	1.1	(13.8)
Distributions from unconsolidated affiliates	23.7	12.0	2.3	8.3	8.7	11.2	18.0
Capitalized interest	(16.1)	(28.0)	(13.6)	(3.4)	(1.3)	(9.1)	(14.3)
Income as adjusted	$ 670.4	$ 399.2	$ 330.7	$ 361.9	$ 256.9	$ 385.0	$ 509.8
Ratio of earnings to fixed charges	4.0	2.4	2.4	3.1	2.2	2.0	4.1

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Joe Bob Perkins, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "registrant");

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 3, 2015

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Matthew J. Meloy, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “registrant”);

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 3, 2015

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

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “Partnership”) for the three months ended September 30, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: November 3, 2015

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

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “Partnership”) for the three months ended September 30, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

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

Date: November 3, 2015

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