TARGA RESOURCES CORP.

FORM 8-K
(Current report filing)

Filed 11/02/17 for the Period Ending 11/02/17

Address	TARGA RESOURCES PARTNERS LP 1000 LOUISIANA STREET, SUITE 4300 HOUSTON, TX, 77002
Telephone	713-584-1000
CIK	0001389170
Symbol	TRGP
SIC Code	4922 - Natural Gas Transmission
Industry	Oil & Gas Transportation Services
Sector	Energy
Fiscal Year	12/31

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

FORM 8-K

CURRENT REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
Date of Report (Date of earliest event reported):
November 2, 2017

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware	**001-34991**	**20-3701075**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(IRS Employer Identification No.)

1000 Louisiana, Suite 4300
Houston, TX 77002
(Address of principal executive office and Zip Code)

(713) 584-1000
(Registrants' telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter). Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 2.02 Results of Operations and Financial Condition.

On November 2, 2017, Targa Resources Corp. (the "Company") issued a press release regarding its financial results for the three months ended September 30, 2017. A conference call to discuss these results is scheduled for 11:00 a.m. Eastern time (10:00 a.m. Central time) on Thursday, November 2, 2017. The conference call will be webcast live and a replay of the webcast will be available through the Investors section of the Company's web site

(http://www.targaresources.com). A copy of the earnings press release is furnished as Exhibit 99.1 to this report, which is hereby incorporated by reference into this Item 2.02.

The press release and accompanying schedules and/or the conference call discussions include the non-generally accepted accounting principles ("non-GAAP") financial measures of distributable cash flow, gross margin, operating margin and adjusted EBITDA. The press release provides reconciliations of these non-GAAP financial measures to their most directly comparable financial measure calculated and presented in accordance with generally accepted accounting principles in the United States of America ("GAAP"). Our non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net cash provided by operating activities, net income (loss) or any other GAAP measure of liquidity or financial performance.

The information furnished pursuant to this Item 2.02, including Exhibit 99.1, shall not be deemed to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and will not be incorporated by reference into any filing under the Securities Act of 1933, as amended, unless specifically identified therein as being incorporated therein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit Number	Description
Exhibit 99.1	Targa Resources Corp. Press Release dated November 2, 2017 .

SIGNATURES

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

Targa Resources Corp.

Date: November 2, 2017

By:/s/ Matthew J. Meloy
Matthew J. Meloy
Executive Vice President and Chief Financial Officer

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Targa Resources Corp. Reports
Third Quarter 2017 Financial Results

HOUSTON – November 2, 2017 - Targa Resources Corp. (NYSE: TRGP) ("TRC", the "Company" or "Targa") today reported third quarter 2017 results.

Third Quarter 2017 Financial Results

Third quarter 2017 net loss attributable to Targa Resources Corp. was ($167.6) million compared to a net loss of ($10.7) million for the third quarter of 2016. The third quarter of 2017 included a pre-tax non-cash loss of $378.0 million from the impairment of property, plant and equipment related to TRC's North Texas operations and included a pre-tax non-cash gain of $126.8 million from a reduction in fair value of contingent consideration.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $276.5 million for the third quarter of 2017 compared to $245.3 million for the third quarter of 2016 (see the section of this release entitled "Targa Resources Corp. - Non-GAAP Financial Measures" for a discussion of Adjusted EBITDA, distributable cash flow, gross margin and operating margin, and reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP")).

"We are pleased with our performance during the third quarter and remain on-track to meet or exceed our full year 2017 operational and financial expectations," said Joe Bob Perkins, Chief Executive Officer of the Company. "We continue to focus on executing our strategic priorities, and as we look forward to 2018 and beyond, are excited about the strength of Targa's long-term outlook. Increasing system volumes in our Gathering and Processing and Downstream segments, combined with our attractive growth program underway, provide line of sight into visible and significant growth in Adjusted EBITDA."

On October 18, 2017, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended September 30, 2017, or $3.64 per share on an annualized basis. Total cash dividends of approximately $196.2 million will be paid on November 15, 2017 on all outstanding shares of common stock to holders of record as of the close of business on November 1, 2017. Also on October 18, 2017, TRC declared a quarterly cash dividend of $23.75 per share of its Series A Preferred Stock. Total cash dividends of approximately $22.9 million will be paid on November 14, 2017 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on November 1, 2017.

The Company reported distributable cash flow for the third quarter of 2017 of $186.6 million compared to total common dividends to be paid of $196.2 million and total Series A Preferred Stock dividends to be paid of $22.9 million.

Third Quarter 2017 - Capitalization, Liquidity and Financing

The Company's total consolidated debt as of September 30, 2017 was $4,897.0 million including $435.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility due 2020. The consolidated debt included $4,462.0 million of Targa Resource Partners LP ("TRP" or "the Partnership") debt, net of $24.6 million of debt issuance costs, with $430.0 million outstanding under TRP's $1.6 billion senior secured revolving credit facility due 2020, $278.1 million outstanding under TRP's accounts receivable securitization facility and $3,778.5 million of outstanding TRP senior notes, net of unamortized premiums.

As of September 30, 2017, TRC had available borrowing capacity under its senior secured revolving credit facility of $235.0 million. TRP had $430.0 million of borrowings outstanding under its $1.6 billion senior secured revolving credit facility and $22.4 million in outstanding letters of credit, resulting in available senior secured revolving credit facility capacity of $1,147.6 million at the Partnership. Total consolidated liquidity of the Company as of September 30, 2017, including $114.1 million of cash, was approximately $1.5 billion.

In October 2017, the Partnership issued $750.0 million aggregate principal amount of 5% Senior Notes due January 2028. The Partnership used the net proceeds of $744.4 million after costs from this offering to redeem its 5% Senior Notes due 2018, reduce borrowings under its credit facilities, and for general partnership purposes.

2017 Forecasted Capital Expenditures Update

Targa expects 2017 net growth capital expenditures for announced projects will be approximately $1,320.0 million. Targa continues to expect that 2017 net maintenance capital expenditures will be approximately $110.0 million.

Conference Call

The Company will host a conference call for the investment community at 11:00 a.m. Eastern time (10:00 a.m. Central time) on November 2, 2017 to discuss third quarter 2017 results. The conference call can be accessed via webcast through the Events and Presentations section of Targa's website at www.targaresources.com , by going directly to http://ir.targaresources.com/trc/events.cfm or by dialing 877-881-2598. The conference ID number for the dial-in is 6883649. Please dial in ten minutes prior to the scheduled start time. A replay will be available approximately two hours following the completion of the webcast through the Investors section of the Company's website. Presentation slides will also be available in the Events and Presentations section of the Company's website, or directly at http://ir.targaresources.com/trc/events.cfm.

Targa Resources Corp. – Consolidated Financial Results of Operations

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	2017 vs. 2016		Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	2017 vs. 2016	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 1,871.5	$ 1,398.7	$ 472.8	34%	$ 5,353.1	$ 3,882.9	$ 1,470.2	38%
Fees from midstream services	260.3	253.6	6.7	3%	759.0	795.5	(36.5)	(5%)
Total revenues	2,131.8	1,652.3	479.5	29%	6,112.1	4,678.4	1,433.7	31%
Product purchases	1,663.1	1,222.7	440.4	36%	4,737.8	3,378.9	1,358.9	40%
Gross margin (1)	468.7	429.6	39.1	9%	1,374.3	1,299.5	74.8	6%
Operating expenses	155.5	143.0	12.5	9%	462.7	414.0	48.7	12%
Operating margin (1)	313.2	286.6	26.6	9%	911.6	885.5	26.1	3%
Depreciation and amortization expense	208.3	184.0	24.3	13%	602.8	563.6	39.2	7%
General and administrative expense	49.9	46.1	3.8	8%	149.5	138.3	11.2	8%
Impairment of property, plant and equipment	378.0	—	378.0	—	378.0	—	378.0	—
Impairment of goodwill	—	—	—	—	—	24.0	(24.0)	(100%)
Other operating (income) expense	0.6	4.9	(4.3)	(88%)	17.2	6.1	11.1	182%
Income from operations	(323.6)	51.6	(375.2)	NM	(235.9)	153.5	(389.4)	(254%)
Interest expense, net	(56.1)	(62.7)	6.6	11%	(181.2)	(187.0)	5.8	3%
Equity earnings (loss)	0.2	(2.2)	2.4	109%	(16.6)	(11.4)	(5.2)	46%
Gain (loss) from financing activities	—	—	—	—	(16.5)	21.4	(37.9)	(177%)
Change in contingent considerations	126.8	0.3	126.5	NM	125.6	0.3	125.3	NM
Other income (expense), net	0.2	1.1	(0.9)	(82%)	(2.7)	0.9	(3.6)	NM
Income tax (expense) benefit	97.4	8.7	88.7	NM	132.3	3.9	128.4	NM
Net income (loss)	(155.1)	(3.2)	(151.9)	NM	(195.0)	(18.4)	(176.6)	NM
Less: Net income attributable to noncontrolling interests	12.5	7.5	5.0	67%	34.3	18.2	16.1	88%
Net income (loss) attributable to Targa Resources Corp.	(167.6)	(10.7)	(156.9)	NM	(229.3)	(36.6)	(192.7)	NM
Dividends on Series A Preferred Stock	22.9	22.9	—	—	68.8	49.7	19.1	38%
Deemed dividends on Series A Preferred Stock	6.5	5.8	0.7	12%	19.0	12.3	6.7	54%
Net income (loss) attributable to common shareholders	$ (197.0)	$ (39.4)	$ (157.6)	NM	$ (317.1)	$ (98.6)	$ (218.5)	222%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	$ 276.5	$ 245.3	$ 31.2	13%	$ 811.1	$ 767.1	$ 44.0	6%
Distributable cash flow (1)	186.6	168.3	18.3	11%	576.7	516.0	60.7	12%
Capital expenditures	378.7	134.6	244.1	181%	987.7	426.5	561.2	132%
Business acquisition (2)	—	—	—	—	987.1	—	987.1	—
Operating statistics: (3)								
Crude oil gathered, Badlands, MBbl/d	108.7	103.9	4.8	5%	111.6	105.7	5.9	6%
Crude oil gathered, Permian, MBbl/d (4)	35.7	—	35.7	—	24.6	—	24.6	—
Plant natural gas inlet, MMcf/d (5) (6)	3,621.4	3,356.6	264.8	8%	3,418.5	3,422.3	(3.8)	—
Gross NGL production, MBbl/d	346.2	310.4	35.8	12%	318.9	305.4	13.5	4%
Export volumes, MBbl/d (7)	154.5	156.7	(2.2)	(1%)	175.5	173.0	2.5	1%
Natural gas sales, BBtu/d (6) (8)	2,054.1	1,993.0	61.1	3%	1,942.5	1,975.4	(32.9)	(2%)
NGL sales, MBbl/d (8)	497.6	497.3	0.3	—	501.6	520.6	(19.0)	(4%)
Condensate sales, MBbl/d	11.4	10.0	1.4	14%	11.5	10.3	1.2	12%

(1) Gross margin, operating margin, adjusted EBITDA, and distributable cash flow are non-GAAP financial measures and are discussed under "Targa Resources Corp. – Non-GAAP Financial Measures."
(2) Includes the acquisition date fair value of the potential earn-out payments of $416.3 million due in 2018 and 2019.

(3) 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.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. For the volume statistics presented, the numerator is the total volume sold during the period of the Company's ownership while the denominator is the number of calendar days during the quarter.
(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) Export volumes represent the quantity of NGL products delivered to third-party customers at the Company's Galena Park Marine Terminal that are destined for international markets.
(8) Includes the impact of intersegment eliminations.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The increase in commodity sales was primarily due to higher commodity prices ($443.3 million) and increased volumes ($40.0 million), partially offset by the impact of hedge settlements ($10.5 million). Fee-based and other revenues increased primarily due to higher gas processing fees.

The increase in product purchases was primarily due to the impact of higher commodity prices and increased volumes.

In the third quarter of 2017, the Company experienced limited impacts to its operations as a result of Hurricane Harvey. The Company incurred: (i) flooding at its Mont Belvieu facilities that resulted in temporary constraints on the receipt of NGLs and the temporary removal of fractionators from service at CBF, resulting in increased levels of mixed NGLs in storage and (ii) the shut-in of the Company's Galena Park Marine Terminal for approximately one week due to the closure of the Houston Ship Channel. The Company's operating margin for the three months ended September 30, 2017, was reduced by approximately $10 million as a result of Hurricane Harvey, comprised of the impact on the Mont Belvieu and Galena Park Marine Terminal facilities along with lost operating margin associated with temporary production disruptions for a limited number of the Company's producer and downstream customers. The Company expects to recover approximately $7 million of the reduced operating margin during the fourth quarter of 2017 when the additional stored volumes of mixed NGLs are fractionated and sold. No property insurance claims are expected as a result of the storm as damage to the Company's facilities was minimal. Business interruption insurance claims related to the storm are expected to be minimal.

The higher operating margin and gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating expenses increased compared to 2016 due to the impact of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement of operations of the Raptor Plant at SouthTX in the Gathering and Processing segment, and higher labor, repairs and maintenance expense in the Logistics and Marketing segment. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased primarily due to the impact of the Permian Acquisition and other growth investments.

General and administrative expense increased primarily due to higher compensation and benefits, partially offset by lower professional services.

The impairment of property, plant and equipment in 2017 reflects an impairment as of September 30, 2017 of gas processing facilities and gathering systems associated with the Company's North Texas operations in the Gathering and Processing segment. The impairment is a result of the Company's current assessment that forecasted undiscounted future net cash flows from operations, while positive, will not be sufficient to recover the existing total net book value of the underlying assets. Given the current price environment, the Company is projecting a continuing decline in natural gas production across the Barnett Shale in North Texas due in part to producers pursuing more attractive opportunities in other basins.

Other operating expense in 2016 included the loss on decommissioning of two storage wells at the Company's Hattiesburg facility and an acid gas injection well at the Company's Versado facility.

Net interest expense decreased primarily due to the impact of lower average outstanding borrowings and higher capitalized interest during 2017, partially offset by higher non-cash interest expense related to the mandatorily redeemable preferred interests that is revalued quarterly at the estimated redemption value as of the reporting date.

During 2017, the Company recorded other income of $126.8 million resulting from the change in the fair value of contingent considerations, substantially all of which was due to the reduction in fair value as of September 30, 2017 of the Permian Acquisition contingent consideration liability, which is based on a multiple of gross margin realized during the first two annual periods after the acquisition date. The decrease in fair value was primarily related to reductions in actual and forecasted volumes and gross margin as a result of changes in producers' drilling activity in the region since the acquisition date. Such changes in estimated fair value of the contingent consideration are attributable to events and circumstances that occurred after the acquisition date, and as such are recognized in earnings. The fair value of the contingent consideration represents the Company's current view of the future payment amounts, and may decrease or increase until the settlement dates, resulting in the recognition of additional other income (expense).

The income tax benefit increased in 2017 primarily due to an increased loss before income taxes.

Net income attributable to noncontrolling interests was higher in 2017 due to increased earnings at the Company's joint ventures as compared with 2016.

Preferred dividends represent both cash dividends related to the offering of Series A Preferred Stock in March 2016 (the "March 2016 Series A Preferred Stock Offering") and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The increase in commodity sales was primarily due to higher commodity prices ($1,600.9 million) and increased petroleum products and condensate volumes ($44.0 million), partially offset by decreased NGL and natural gas sales volumes ($126.0 million) and the impact of hedge settlements ($48.7 million). Fee-based and other revenues decreased primarily due to lower export fees, partially offset by increases in gas processing and crude gathering fees.

The increase in product purchases was primarily due to the impact of higher commodity prices, partially offset by decreased volumes.

In the third quarter of 2017, the Company experienced limited impacts to their operations as a result of Hurricane Harvey. The Company's operating margin for the nine months ended September 30, 2017, was reduced by approximately $10 million as a result of Hurricane Harvey, comprised of the impact on the Mont Belvieu and Galena Park Marine Terminal facilities along with lost operating margin associated with temporary production disruptions for a limited number of the Company's producer and chemical customers. The Company expects to recover approximately $7 million of the reduced operating margin during the fourth quarter of 2017 when the additional stored volumes of mixed NGLs are fractionated and sold.

The higher operating margin and gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating expenses increased compared to 2016 due to the impact of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement of operations of the Raptor Plant at SouthTX in the Gathering and Processing segment, and higher fuel and power that is largely passed through in the Logistics and Marketing segment. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased primarily due to the impact of the March 2017 Permian Acquisition and the impact of other growth investments, including CBF Train 5 that went into service in the second quarter of 2016 and the Raptor Plant at SouthTX that went into service in the second quarter of 2017.

General and administrative expense increased primarily due to higher compensation and benefits, partially offset by lower professional services.

The impairment of property, plant and equipment in 2017 reflects an impairment of gas processing facilities and gathering systems associated with the Company's North Texas operations in the Gathering and Processing segment (described above).

In the first quarter of 2016, the Company recognized a $24.0 million adjustment to a provisional impairment of goodwill recorded in the fourth quarter of 2015 related to goodwill acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively the "Atlas mergers").

Other operating expense in 2017 is primarily due to the reduction in the carrying value of the Company's ownership interest in the Venice Gathering System in connection with the April 2017 sale. Other operating expense in 2016 is primarily due to the loss on decommissioning two storage wells at the Company's Hattiesburg facility and an acid gas injection well at the Company's Versado facility.

Net interest expense in 2017 decreased as compared with 2016 primarily due to lower average outstanding borrowings during 2017, partially offset by higher non-cash interest expense related to the mandatorily redeemable preferred interests that is revalued quarterly at the estimated redemption value as of the reporting date.

Higher equity losses in 2017 reflects a $12.0 million loss provision due to the impairment of the Company's investment in the T2 EF Cogen joint venture, partially offset by increased equity earnings at Gulf Coast Fractionators.

During 2017, the Company recorded a loss from financing activities of $16.5 million on the redemption of the outstanding 6⅜% Senior Notes and the repayment of the outstanding balance on the Company's senior secured term loan, whereas in 2016 the Company recorded a gain of $21.4 million on open market debt repurchases.

During 2017, the Company recorded other income of $125.6 million resulting from the change in the fair value of contingent considerations, substantially all of which was due to the reduction in fair value as of September 30, 2017 of the Permian Acquisition contingent consideration liability.

The Company has historically calculated the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to ordinary income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period. When calculating the annual estimated effective income tax rate for the nine months ended September 30, 2017, the Company was subject to a loss limitation rule because the year-to-date ordinary loss is expected to exceed the full-year expected ordinary loss. The tax benefit for that year-to-date ordinary loss was limited to the amount that would be recognized if the year-to-date ordinary loss were the anticipated ordinary loss for the full year. This requires the Company to use its statutory rate of 37.3% rather than the annual estimated effective tax rate to calculate the benefit for the period.

Net income attributable to noncontrolling interests was higher in 2017 due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for a portion of the first quarter of 2016, and the Company's October 2016 acquisition of the 37% interest of Versado that the Company did not already own. Further, earnings at the Company's joint ventures increased as compared with 2016.

Preferred dividends represent both cash dividends related to the March 2016 Series A Preferred Stock Offering and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. Preferred dividends increased as the Series A Preferred Stock was outstanding for three full quarters in 2017, as compared to a portion of 2016.

Review of Segment Performance

The following discussion of segment performance includes inter-segment activities. The Company views segment operating margin as an important performance measure of the core profitability of its operations. This measure is a key component of internal financial reporting and is reviewed for consistency and trend analysis. For a discussion of operating margin, see "Targa Resources Corp. - Non-GAAP Financial Measures - Operating Margin." Segment operating financial results and operating statistics include the effects of intersegment transactions. These intersegment transactions have been eliminated from the consolidated presentation.

The Company operates in two primary segments: (i) Gathering and Processing; and (ii) Logistics and Marketing.

Gathering and Processing Segment

The Gathering and Processing segment 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 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; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

The following table provides summary data regarding results of operations of this segment for the periods indicated:

Exhibit 99.1

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	2017 vs. 2016		Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	2017 vs. 2016	
Gross margin	$ 289.7	$ 231.7	$ 58.0	25%	$ 817.1	$ 648.0	$ 169.1	26%
Operating expenses	91.4	82.3	9.1	11%	267.8	243.9	23.9	10%
Operating margin	$ 198.3	$ 149.4	$ 48.9	33%	$ 549.3	$ 404.1	$ 145.2	36%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2), (3)								
SAOU (4)	324.6	262.5	62.1	24%	304.1	255.1	49.0	19%
WestTX	607.5	506.0	101.5	20%	560.8	480.8	80.0	17%
Total Permian Midland	932.1	768.5	163.6		864.9	735.9	129.0	
Sand Hills (4)	193.0	140.9	52.1	37%	171.6	142.6	29.0	20%
Versado	210.9	180.6	30.3	17%	202.0	176.5	25.5	14%
Total Permian Delaware	403.9	321.5	82.4		373.6	319.1	54.5	
Total Permian	1,336.0	1,090.0	246.0		1,238.5	1,055.0	183.5	
SouthTX	330.1	218.0	112.1	51%	242.1	219.7	22.4	10%
North Texas	261.8	315.2	(53.4)	(17%)	273.7	323.4	(49.7)	(15%)
SouthOK	515.2	469.8	45.4	10%	478.5	466.1	12.4	3%
WestOK	367.1	434.4	(67.3)	(15%)	382.5	455.6	(73.1)	(16%)
Total Central	1,474.2	1,437.4	36.8		1,376.8	1,464.8	(88.0)	
Badlands (5)	60.9	53.8	7.1	13%	53.1	52.9	0.2	—
Total Field	2,871.1	2,581.2	289.9		2,668.4	2,572.7	95.7	
Coastal	750.5	775.5	(25.0)	(3%)	750.1	849.7	(99.6)	(12%)
Total	3,621.6	3,356.7	264.9	8%	3,418.5	3,422.4	(3.9)	—
Gross NGL production, MBbl/d (3)								
SAOU (4)	38.7	32.8	5.9	18%	36.6	31.4	5.2	17%
WestTX	84.1	67.6	16.5	24%	75.2	60.7	14.5	24%
Total Permian Midland	122.8	100.4	22.4		111.8	92.1	19.7	
Sand Hills (4)	21.0	15.2	5.8	38%	18.6	15.0	3.6	24%
Versado	25.3	21.8	3.5	16%	23.8	21.3	2.5	12%
Total Permian Delaware	46.3	37.0	9.3		42.4	36.3	6.1	
Total Permian	169.1	137.4	31.7		154.2	128.4	25.8	
SouthTX	35.4	20.9	14.5	69%	25.2	25.1	0.1	—
North Texas	29.3	36.2	(6.9)	(19%)	30.8	36.3	(5.5)	(15%)
SouthOK	42.7	42.4	0.3	1%	40.7	39.3	1.4	4%
WestOK	20.7	27.2	(6.5)	(24%)	22.3	27.9	(5.6)	(20%)
Total Central	128.1	126.7	1.4		119.0	128.6	(9.6)	
Badlands	9.0	7.8	1.2	15%	7.4	7.5	(0.1)	(1%)
Total Field	306.2	271.9	34.3		280.6	264.5	16.1	
Coastal	40.0	38.6	1.4	4%	38.2	41.0	(2.8)	(7%)
Total	346.2	310.5	35.7	11%	318.8	305.5	13.3	4%
Crude oil gathered, Badlands, MBbl/d	108.7	103.9	4.8	5%	111.6	105.7	5.9	6%
Crude oil gathered, Permian, MBbl/d (4)	35.7	—	35.7	—	24.6	—	24.6	—
Natural gas sales, BBtu/d (3)	1,738.5	1,617.6	120.9	7%	1,647.8	1,636.8	11.0	1%
NGL sales, MBbl/d	244.4	248.4	(4.0)	(2%)	240.4	241.3	(0.9)	—
Condensate sales, MBbl/d	11.4	9.7	1.7	18%	11.4	10.0	1.4	14%
Average realized prices (6):								
Natural gas, $/MMBtu	2.58	2.49	0.09	4%	2.71	1.96	0.75	38%
NGL, $/gal	0.56	0.36	0.20	56%	0.51	0.33	0.18	55%
Condensate, $/Bbl	42.69	38.29	4.40	11%	43.42	34.18	9.24	27%

(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.

(2) Plant natural gas inlet represents the Company's undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.

(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.

(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills. For the volume statistics presented, the numerator is the total volume sold during the period of the Company's ownership while the denominator is the number of calendar days during the quarter.
(5) Badlands natural gas inlet represents the total wellhead gathered volume.
(6) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition. Field Gathering and Processing inlet volume increases included all areas in the Permian region, as well as SouthTX, Badlands and SouthOK, partially offset by decreases at WestOK and North Texas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower unit margins, partially offset the Field Gathering and Processing inlet volume increase. NGL production and natural gas sales increased primarily due to increased Field Gathering and Processing inlet volumes. The decrease in NGL sales was primarily due to the deferral to the fourth quarter of 2017 of NGL sales impacted by the temporary operational issues related to Hurricane Harvey. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total Badlands crude oil gathered volumes and natural gas volumes increased primarily due to system expansions.

The increase in operating expenses was primarily driven by the inclusion of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes including those associated with the Permian Acquisition. Field Gathering and Processing inlet volume increases included all areas in the Permian region, as well as SouthTX and SouthOK, partially offset by decreases at WestOK and North Texas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower unit margins, more than offset the Field Gathering and Processing inlet volume increase. Despite overall lower inlet volumes, NGL production increased primarily due to increased plant recoveries including additional ethane recovery. Third quarter NGL sales were reduced due to the deferral to the fourth quarter of 2017 of NGL sales impacted by the temporary operational issues related to Hurricane Harvey. Natural gas sales increased primarily due to increased Field Gathering and Processing inlet volumes. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total Badlands crude oil gathered increased due to system expansions. Badlands natural gas volumes were relatively flat primarily due to the impact of the severe winter weather in the first quarter of 2017.

The increase in operating expenses was primarily driven by the inclusion of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

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 portion of the Gathering and Processing segment:

Exhibit 99.1

	Three Months Ended September 30, 2017			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	324.6	100%	324.6	324.6
WestTX (5) (6)	834.5	73%	607.5	607.5
Total Permian Midland	1,159.1		932.1	932.1
Sand Hills (4)	193.0	100%	193.0	193.0
Versado (7)	210.9	100%	210.9	210.9
Total Permian Delaware	403.9		403.9	403.9
Total Permian	1,563.0		1,336.0	1,336.0
SouthTX	330.1	Varies (8) (9)	260.0	330.1
North Texas	261.8	100%	261.8	261.8
SouthOK	515.2	Varies (10)	412.1	515.2
WestOK	367.1	100%	367.1	367.1
Total Central	1,474.2		1,301.0	1,474.2
Badlands (11)	60.9	100%	60.9	60.9
Total Field	3,098.1		2,697.9	2,871.1
Gross NGL production, MBbl/d (2)				
SAOU (4)	38.7	100%	38.7	38.7
WestTX (5) (6)	115.5	73%	84.1	84.1
Total Permian Midland	154.2		122.8	122.8
Sand Hills (4)	21.0	100%	21.0	21.0
Versado (7)	25.3	100%	25.3	25.3
Total Permian Delaware	46.3		46.3	46.3
Total Permian	200.5		169.1	169.1
SouthTX	35.4	Varies (8) (9)	28.6	35.4
North Texas	29.3	100%	29.3	29.3
SouthOK	42.7	Varies (10)	34.6	42.7
WestOK	20.7	100%	20.7	20.7
Total Central	128.1		113.2	128.1
Badlands	9.0	100%	9.0	9.0
Total Field	337.6		291.3	306.2

(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.
(3) For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills.
(5) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.
(6) Includes the Buffalo Plant that commenced commercial operations in April 2016.
(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials. The Company held a 63% interest in Versado until October 31, 2016, when the Company acquired the remaining 37% interest.
(8) SouthTX includes the Silver Oak II Plant, of which the Company owned a 90% interest from October 2015 through May 2017, and after which the Company owns a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(9) SouthTX also includes the Raptor Plant, which began operations in the second quarter of 2017, of which the Company owns a 50% interest through the Carnero Processing Joint Venture. The Carnero Processing Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(10) SouthOK includes the Centrahoma Joint Venture, of which the Company owns 60%, and other plants which are owned 100% by the Company. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(11) Badlands natural gas inlet represents the total wellhead gathered volume.

	Three Months Ended September 30, 2016			
Operating statistics: **Plant natural gas inlet, MMcf/d (1),(2)**	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU	262.5	100%	262.5	262.5
WestTX (4)	695.0	73%	506.0	506.0
Total Permian Midland	957.5		768.5	768.5
Sand Hills	140.9	100%	140.9	140.9
Versado (5)	180.6	63%	113.8	180.6
Total Permian Delaware	321.5		254.7	321.5
Total Permian	1,279.0		1,023.2	1,090.0
SouthTX	218.0	Varies (6)	205.6	218.0
North Texas	315.2	100%	315.2	315.2
SouthOK	469.8	Varies (7)	392.8	469.8
WestOK	434.4	100%	434.4	434.4
Total Central	1,437.4		1,348.0	1,437.4
Badlands (8)	53.8	100%	53.8	53.8
Total Field	2,770.2		2,425.0	2,581.2
Gross NGL production, MBbl/d (2)				
SAOU	32.8	100%	32.8	32.8
WestTX (4)	92.9	73%	67.6	67.6
Total Permian Midland	125.7		100.4	100.4
Sand Hills	15.2	100%	15.2	15.2
Versado (5)	21.8	63%	13.7	21.8
Total Permian Delaware	37.0		28.9	37.0
Total Permian	162.7		129.3	137.4
SouthTX	20.9	Varies (6)	19.7	20.9
North Texas	36.2	100%	36.2	36.2
SouthOK	42.4	Varies (7)	39.1	42.4
WestOK	27.2	100%	27.2	27.2
Total Central	126.7		122.2	126.7
Badlands	7.8	100%	7.8	7.8
Total Field	297.2		259.3	271.9

(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.
(3) For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(4) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.
(5) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials. The Company held a 63% interest in Versado until October 31, 2016, when the Company acquired the remaining 37% interest.
(6) SouthTX includes the Silver Oak II Plant, of which the Company owned a 90% interest from October 2015 through May 2017, and after which the Company owns a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(7) SouthOK includes the Centrahoma Joint Venture, of which the Company owns 60%, and other plants which are owned 100% by the Company. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(8) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

The Logistics and Marketing segment 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 the Company's other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of the Company's other operations, as well as transporting natural gas and NGLs. The Logistics and Marketing segment also includes the Grand Prix project.

Logistics and Marketing operations are generally connected to and supplied in part by the Company's Gathering and Processing segments and are predominantly located in Mont Belvieu, Galena Park and Channelview, Texas, Lake Charles, Louisiana and Tacoma, Washington.

The following table provides summary data regarding results of operations of this segment for the periods indicated:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	2017 vs. 2016		Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	2017 vs. 2016	
				(In millions)				
Gross margin	$ 180.0	$ 186.7	$ (6.7)	(4%)	$ 553.3	$ 594.6	$ (41.3)	(7%)
Operating expenses	64.1	60.7	3.4	6%	194.8	170.1	24.7	15%
Operating margin	$ 115.9	$ 126.0	$ (10.1)	(8%)	$ 358.5	$ 424.5	$ (66.0)	(16%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	329.3	313.2	16.1	5%	324.3	312.8	11.5	4%
LSNG treating volumes (2)	27.2	25.6	1.6	6%	31.6	23.3	8.3	36%
Benzene treating volumes (2)	16.1	20.2	(4.1)	(20%)	20.5	21.4	(0.9)	(4%)
Export volumes, MBbl/d (4)	154.5	156.7	(2.2)	(1%)	175.5	173.0	2.5	1%
NGL sales, MBbl/d	463.4	452.4	11.0	2%	468.1	466.3	1.8	—
Average realized prices:								
NGL realized price, $/gal	$ 0.67	$ 0.46	$ 0.21	46%	$ 0.64	$ 0.45	$ 0.19	42%

(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 period and the denominator is the number of calendar days during the period.
(2) 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 and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.
(4) Export volumes represent the quantity of NGL products delivered to third-party customers at the Company's Galena Park Marine Terminal that are destined for international markets.

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

Logistics and Marketing gross margin decreased due to lower LPG export margin partially offset by higher fractionation margin, higher marketing gains, and higher terminaling and storage throughput. LPG export margin decreased primarily due to lower fees. LPG export volumes decreased due to the deferral to the fourth quarter of 2017 of 12.5 MBbl/d of export volumes due to the temporary closure of the Houston Ship Channel resulting from Hurricane Harvey. Fractionation margin increased due to higher system product gains, higher supply volume despite the deferral to the fourth quarter of 2017 of 29.3 MBbl/d of supply volumes due to the temporary operational issues related to Hurricane Harvey, and higher fees. Fractionation gross margin was partially impacted by the variable effects of lower fuel and power that are largely reflected in operating expenses (see footnote (2) above).

Operating expenses increased primarily due to higher labor, higher repairs and maintenance, partially offset by lower fuel and power that is largely passed through.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The gross margin results for the nine months ended September 30, 2017 were impacted by the same factors as discussed above for the three months ended September 30, 2017, with the exception of fuel and power, which were higher. Additional factors were lower commercial transportation margin and lower domestic marketing margin. Commercial transportation margin decreased primarily due to lower barge activity. Domestic marketing margin decreased primarily due to lower terminal margins.

Operating expenses increased primarily due to higher fuel and power which is largely passed through, higher labor associated with Train 5, and higher maintenance associated with unusual one-time events in the first quarter of 2017.

Other

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	2017 vs. 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	2017 vs. 2016
			(In millions)			
Gross margin	$ (1.0)	$ 11.2	$ (12.2)	$ 3.9	$ 56.9	$ (53.0)
Operating margin	$ (1.0)	$ 11.2	$ (12.2)	$ 3.9	$ 56.9	$ (53.0)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash flow hedges. The primary purpose of the Company's commodity risk management activities is to mitigate a portion of the impact of commodity prices on the Company's operating cash flow. The Company has entered into derivative instruments to hedge the commodity price associated with a portion of the Company's expected natural gas, NGL and condensate equity volumes in the Company's Gathering and Processing Operations that result from percent of proceeds/liquids processing arrangements. Because the Company is essentially forward-selling a portion of its future 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, 2017			Three Months Ended September 30, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	17.3	$ 0.23	$ 4.0	13.8	$ 0.37	$ 5.1	$ (1.1)
NGL (MMgal)	74.8	(0.09)	(6.7)	(7.2)	(0.25)	1.8	(8.5)
Crude oil (MBbl)	0.4	6.29	2.3	0.3	14.40	4.7	(2.4)
Non-hedge accounting (2)			(0.6)			(0.1)	(0.5)
Ineffectiveness (3)			-			(0.3)	0.3
			$ (1.0)			$ 11.2	$ (12.2)

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	43.3	$ 0.15	$ 6.6	34.0	$ 0.94	$ 31.9	$ (25.3)
NGL (MMgal)	177.5	(0.04)	(7.7)	20.2	0.34	6.9	(14.6)
Crude oil (MBbl)	0.9	6.29	5.8	0.8	20.02	16.2	(10.4)
Non-hedge accounting (2)			(0.9)			2.5	(3.4)
Ineffectiveness (3)			0.1			(0.6)	0.7
			$ 3.9			$ 56.9	$ (53.0)

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(3) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of Targa Pipeline Partners, L.P. ("TPL") that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of February 27, 2015 (the "acquisition date"), were novated to the Company and included in the acquisition date fair value of assets acquired. The Company received derivative settlements of $1.4 million and $6.3 million for the three and nine months ended September 30, 2017 and $5.8 million and $20.9 million for the three and nine months ended September 30, 2016, related to these novated contracts. From the acquisition date through September 30, 2017, the Company has received total derivative settlements of $100.9 million. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

About Targa Resources Corp.

Targa Resources Corp. is a leading provider of midstream services and is one of the largest independent midstream energy companies in North America. The Company owns, operates, acquires, and develops a diversified portfolio of complementary midstream energy assets. The Company is primarily 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.

For more information, please visit our website at www.targaresources.com .

Targa Resources Corp. - Non-GAAP Financial Measures

This press release includes the Company's non-GAAP financial measures Adjusted EBITDA, distributable cash flow, gross margin and operating margin. The tables below provide reconciliations of these non-GAAP financial measures to their most directly comparable GAAP measures. The Company's non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income, operating income, net cash flows provided by operating activities or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA

The Company defines Adjusted EBITDA as net income (loss) available to TRC before: interest; income taxes; depreciation and amortization; impairments of goodwill and property, plant and equipment; 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 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015; non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by the Company and by external users of the Company's financial statements such as investors, commercial banks and others. The economic substance behind the Company's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and pay dividends to its investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to TRC. Adjusted EBITDA should not be considered as an alternative to 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 the Company's results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in the Company's industry, the Company's 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

The Company defines distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, the Splitter Agreement adjustment, cash interest expense on debt obligations, cash tax (expense) benefit and maintenance capital expenditures (net of any reimbursements of project costs). This measure includes the impact of noncontrolling interests on the prior adjustment items.

Distributable cash flow is a significant performance metric used by the Company and by external users of the Company's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by it (prior to the establishment of any retained cash reserves by the Company's board of directors) to the cash dividends the Company expects to pay its shareholders. Using this metric, management and external users of its financial statements can quickly compute the coverage ratio of estimated cash flows to cash dividends. Distributable cash flow is also an important financial measure for the Company's shareholders since it serves as an indicator of the Company's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Company is generating cash flow at a level that can sustain or support an increase in its quarterly dividend rates.

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income (loss) attributable to TRC. Distributable cash flow should not be considered as an alternative to GAAP net income (loss) available to common and preferred shareholders. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of the Company's results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in the Company's industry, the Company's 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 the Company's decision-making processes.

The following table presents a reconciliation of net income of the Company to Adjusted EBITDA and Distributable Cash Flow for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ (167.6)	$ (10.7)	$ (229.3)	$ (36.6)
Impact of TRC/TRP Merger on NCI	—	—	—	(3.8)
Income attributable to TRP preferred limited partners	2.8	2.8	8.4	8.4
Interest expense, net	56.1	62.7	181.2	187.0
Income tax expense (benefit)	(97.4)	(8.7)	(132.3)	(3.9)
Depreciation and amortization expense	208.3	184.0	602.8	563.6
Impairment of property, plant and equipment	378.0	—	378.0	—
Impairment of goodwill	—	—	—	24.0
(Gain) loss on sale or disposition of assets	0.3	4.7	16.6	5.7
(Gain) loss from financing activities	—	—	16.5	(21.4)
(Earnings) loss from unconsolidated affiliates	(0.2)	2.2	16.6	11.4
Distributions from unconsolidated affiliates and preferred partner interests, net	4.6	3.8	15.0	12.6
Change in contingent consideration included in Other expense	(126.8)	(0.3)	(125.6)	(0.3)
Compensation on equity grants	10.2	7.0	31.7	22.2
Transaction costs related to business acquisitions	0.4	—	5.6	—
Splitter Agreement (1)	10.8	—	32.3	—
Risk management activities	2.0	6.2	7.2	18.7
Noncontrolling interests adjustments (2)	(5.0)	(8.4)	(13.6)	(20.5)
TRC Adjusted EBITDA	**$ 276.5**	**$ 245.3**	**$ 811.1**	**$ 767.1**
Distributions to TRP preferred limited partners	(2.8)	(2.8)	(8.4)	(8.4)
Splitter Agreement (1)	(10.8)	—	(32.3)	—
Interest expense on debt obligations (3)	(52.8)	(65.5)	(168.5)	(201.1)
Cash tax (expense) benefit (4)	—	11.1	46.7	11.1
Maintenance capital expenditures	(24.0)	(21.1)	(73.0)	(56.3)
Noncontrolling interests adjustments of maintenance capex	0.5	1.3	1.1	3.6
Distributable Cash Flow	**$ 186.6**	**$ 168.3**	**$ 576.7**	**$ 516.0**

(1) In Adjusted EBITDA, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the condensate splitter agreement over the four quarters following receipt. In Distributable Cash Flow, the Splitter Agreement adjustment represents the amounts necessary to reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA.
(2) Noncontrolling interest portion of depreciation and amortization expense.
(3) Excludes amortization of interest expense.
(4) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which was recognized over the periods between the third quarter 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before the fourth quarter of 2017, was received in the second quarter of 2017. As a result, the remaining $20.9 million unamortized balance of the tax refund was included in Distributable Cash Flow in the second quarter of 2017. The nine months ended September 30, 2017 also includes a refund of Texas margin tax paid in previous periods and received in 2017.

Gross Margin

The Company defines gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by the Company’s contract mix and commodity hedging program.

Gathering and Processing segment gross margin consists primarily of revenues from the sale of natural gas, condensate, crude oil and NGLs and fee revenues related to natural gas and crude oil gathering and services, less producer payments and other natural gas and crude oil purchases.

Logistics and Marketing segment gross margin consists primarily of:

- service fee revenues (including the pass-through of energy costs included in fee rates),
- system product gains and losses, and

- NGL and natural gas sales less NGL and natural gas purchases, transportation costs and the net inventory change.

The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

The Company defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of its operations.

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

- the financial performance of the Company's assets without regard to financing methods, capital structure or historical cost basis;
- the Company's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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 the Company's 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 the Company's industry, the Company's definitions of gross margin and operating margin may not be comparable with 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.

The following table presents a reconciliation of net income to operating margin and gross margin for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ (167.6)	$ (10.7)	$ (229.3)	$ (36.6)
Net income (loss) attributable to noncontrolling interests	12.5	7.5	34.3	18.2
Net income (loss)	(155.1)	(3.2)	(195.0)	(18.4)
Depreciation and amortization expense	208.3	184.0	602.8	563.6
General and administrative expense	49.9	46.1	149.5	138.3
Impairment of property, plant and equipment	378.0	—	378.0	—
Impairment of goodwill	—	—	—	24.0
Interest expense, net	56.1	62.7	181.2	187.0
Income tax expense (benefit)	(97.4)	(8.7)	(132.3)	(3.9)
(Gain) loss on sale or disposition of assets	0.3	4.7	16.6	5.7
(Gain) loss from financing activities	—	—	16.5	(21.4)
Other, net	(126.9)	1.0	(105.7)	10.6
Operating margin	313.2	286.6	911.6	885.5
Operating expenses	155.5	143.0	462.7	414.0
Gross margin	**$ 468.7**	**$ 429.6**	**$ 1,374.3**	**$ 1,299.5**

Forward-Looking Statements

Exhibit 99.1

Certain statements in this release are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this release that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future, are forward-looking statements. These forward-looking statements rely on a number of assumptions concerning future events and are subject to a number of uncertainties, factors and risks, many of which are outside the Company’s control, which could cause results to differ materially from those expected by management of the Company. Such risks and uncertainties include, but are not limited to, weather, political, economic and market conditions, including a decline in the price and market demand for natural gas, natural gas liquids and crude oil, the timing and success of business development efforts; and other uncertainties. These and other applicable uncertainties, factors and risks are described more fully in the Company’s filings with the Securities and Exchange Commission, including its Annual Report on Form 10-K for the year ended December 31, 2016, and any subsequently filed Quarterly Reports on Form 10-Q and Current Reports on Form 8-K. The Company does not undertake an obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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