Targa Resources Corp. Logo

Targa Resources Corp. Reports Third Quarter 2018 Financial Results and Provides Update on Growth Projects, Financing and Longer-Term Outlook

November 8, 2018

HOUSTON, Nov. 08, 2018 (GLOBE NEWSWIRE) -- Targa Resources Corp. (NYSE: TRGP) ("TRC", the "Company" or "Targa") today reported third quarter 2018 results.

Third Quarter 2018 Financial Results

Third quarter 2018 net loss attributable to Targa Resources Corp. was ($23.7) million compared to ($167.6) million for the third quarter of 2017.

The Company reported record quarterly earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $358.0 million for the third quarter of 2018 compared to $276.5 million for the third quarter of 2017 (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")).

"This is the strongest quarter in Targa's history across multiple operational and financial dimensions, positioning us to exceed our full year 2018 financial guidance and providing Targa with positive momentum heading into 2019. With continued attractive business fundamentals, strong execution and multiple growth projects on-track to begin operations over the near term, Targa's longer-term growth outlook continues to strengthen," said Joe Bob Perkins, Chief Executive Officer of the Company.

On October 17, 2018, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended September 30, 2018, or $3.64 per share on an annualized basis. Total cash dividends of approximately $208.6 million will be paid on November 15, 2018 on all outstanding shares of common stock to holders of record as of the close of business on October 31, 2018. Also on October 17, 2018, TRC declared a quarterly cash dividend of $23.75 per share for its Series A Preferred Stock. Total cash dividends of approximately $22.9 million will be paid on November 14, 2018 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on October 31, 2018.

The Company reported distributable cash flow for the third quarter of 2018 of $287.2 million compared to total common dividends to be paid of $208.6 million and total Series A Preferred Stock dividends to be paid of $22.9 million. In September 2018, the Company received the annual cash payment of $43 million under its long-term condensate splitter agreement, which is included in distributable cash flow for the third quarter.

Third Quarter 2018 - Capitalization and Liquidity

The Company's total consolidated debt as of September 30, 2018 was $5,968.9 million including $435.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility. The consolidated debt included $5,533.9 million of Targa Resources Partners LP ("TRP" or the "Partnership") debt, net of $34.0 million of debt issuance costs, with $290.0 million outstanding under TRP's accounts receivable securitization facility, $5,277.9 million of outstanding TRP senior unsecured notes and no borrowings outstanding under TRP's $2.2 billion senior secured revolving credit facility.

Total consolidated liquidity of the Company as of September 30, 2018, including $203.2 million of cash, was approximately $2.6 billion. As of September 30, 2018, TRC had available borrowing capacity under its senior secured revolving credit facility of $235.0 million. TRP had $76.6 million in letters of credit outstanding under its $2.2 billion senior secured revolving credit facility, resulting in available senior secured revolving credit facility capacity of $2,123.4 million. In addition to the availability under its senior secured revolving credit facility, the Partnership also had $60.0 million of availability under its accounts receivable securitization facility.

Growth Projects Update

Today, Targa is announcing plans to construct two new 110 thousand barrels per day ("MBbl/d") fractionation trains in Mont Belvieu, Texas, which are expected to begin operations in the first and second quarter of 2020, respectively.

Targa now estimates 2018 net growth capital expenditures for announced projects will be approximately $2.4 billion and estimates that 2018 net maintenance capital expenditures will be approximately $110 million.

Targa also estimates that preliminary 2019 net growth capital expenditures for announced projects will be about $2 billion.

Financing Update

On September 12, 2018, Targa announced it had executed agreements to sell its refined products and crude oil storage and terminaling facilities in Tacoma, WA and Baltimore, MD to an affiliate of ArcLight Capital Partners, LLC for approximately $160 million. The sale closed on October 31, 2018. Targa intends to use the net proceeds to fund a portion of its growth capital program underway.

During the three months ended September 30, 2018, the Company issued 3,696,533 shares of common stock under its Equity Distribution Agreements ("EDAs"), resulting in total net proceeds of $202.4 million. For the nine months ended September 30, 2018, TRC has issued a total of 11,376,528 shares of common stock under its EDAs, resulting in total net proceeds of $572.0 million.

During the nine months ended September 30, 2018, Targa has raised approximately $1 billion in net proceeds from a combination of common stock sales, joint venture reimbursements and completed asset sales.

Today, Targa is also announcing it is evaluating the potential sale of a minority interest in its Badlands assets to a select small group of counterparties. Given the talented team of employees associated with the Badlands assets, the fee-based and long-term nature of the contracts, the strong performance of the assets, and the improving outlook in the Bakken, the Company believes that monetizing a minority interest would provide significant potential benefit to Targa while still retaining control over the operations and strategy of the business.

Updated Longer-Term Outlook

Today, Targa published a revised longer-term Adjusted EBITDA outlook and provided an aggregate preliminary estimate of net growth capital expenditures for 2020 through 2021 in its quarterly earnings supplement presentation and updated investor presentation available in the Events and Presentations section of the Company's website at http://ir.targaresources.com/trc/events.cfm.

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 8, 2018 to discuss third quarter 2018 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 https://edge.media-server.com/m6/p/9qgo9sfy or by dialing 877-881-2598. The conference ID number for the dial-in is 9589340. Please dial in ten minutes prior to the scheduled start time. A webcast replay will be available at the link above approximately two hours after the conclusion of the event.

Targa Resources Corp. – Consolidated Financial Results of Operations

	Three Months Ended September 30,				**Nine Months Ended September 30,**			
	2018	**2017**	**2018 vs. 2017**		**2018**	**2017**	**2018 vs. 2017**	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 2,654.1	$ 1,871.5	$ 782.6	42 %	$ 6,981.4	$ 5,353.1	$ 1,628.3	30 %
Fees from midstream services	332.3	260.3	72.0	28 %	904.9	759.0	145.9	19 %
Total revenues	2,986.4	2,131.8	854.6	40 %	7,886.3	6,112.1	1,774.2	29 %
Product purchases	2,383.5	1,663.1	720.4	43 %	6,229.7	4,737.8	1,491.9	31 %
Gross margin (1)	602.9	468.7	134.2	29 %	1,656.6	1,374.3	282.3	21 %
Operating expenses	194.9	155.5	39.4	25 %	538.7	462.7	76.0	16 %
Operating margin (1)	408.0	313.2	94.8	30 %	1,117.9	911.6	206.3	23 %
Depreciation and amortization expense	206.3	208.3	(2.0)	(1 %)	607.1	602.8	4.3	1 %
General and administrative expense	63.2	49.9	13.3	27 %	176.9	149.5	27.4	18 %
Impairment of property, plant and equipment	—	378.0	(378.0)	(100 %)	—	378.0	(378.0)	(100 %)
Other operating (income) expense	61.8	0.6	61.2	NM	15.7	17.2	(1.5)	(9 %)
Income (loss) from operations	76.7	(323.6)	400.3	124 %	318.2	(235.9)	554.1	235 %
Interest expense, net	(78.2)	(56.1)	(22.1)	39 %	(124.2)	(181.2)	57.0	31 %
Equity earnings (loss)	3.0	0.2	2.8	NM	6.4	(16.6)	23.0	139 %
Gain (loss) from financing activities	—	—	—	—	(2.0)	(16.5)	14.5	88 %
Change in contingent considerations	(16.6)	126.8	(143.4)	(113 %)	(12.1)	125.6	(137.7)	(110 %)
Other income (expense), net	—	0.2	(0.2)	(100 %)	—	(2.7)	2.7	100 %
Income tax (expense) benefit	3.9	97.4	(93.5)	(96 %)	(37.7)	132.3	(170.0)	(128 %)
Net income (loss)	(11.2)	(155.1)	143.9	93 %	148.6	(195.0)	343.6	176 %
Less: Net income (loss) attributable to noncontrolling interests	12.5	12.5	—	—	40.4	34.3	6.1	18 %
Net income (loss) attributable to Targa Resources Corp.	(23.7)	(167.6)	143.9	86 %	108.2	(229.3)	337.5	147 %
Dividends on Series A Preferred Stock	22.9	22.9	—	—	68.8	68.8	—	—
Deemed dividends on Series A Preferred Stock	7.4	6.5	0.9	14 %	21.5	19.0	2.5	13 %
Net income (loss) attributable to common shareholders	$ (54.0)	$ (197.0)	$ 143.0	73 %	$ 17.9	$ (317.1)	$ 335.0	106 %
Financial data:								
Adjusted EBITDA (1)	$ 358.0	$ 276.5	$ 81.5	29 %	$ 990.6	$ 811.1	$ 179.5	22 %
Distributable cash flow (1)	287.2	186.6	100.6	54 %	728.5	576.7	151.8	26 %
Capital expenditures (2)	1,017.7	378.7	639.0	169 %	2,310.4	987.7	1,322.7	134 %
Business acquisition (3)	—	—	—	—	—	987.1	(987.1)	(100 %)

(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) Capital expenditures, net of contributions from noncontrolling interest, were $856.8 million and $1,890.8 million for the three and nine months ended September 30, 2018, and $344.4 million and $889.3 million for the three and nine months ended September 30, 2017.
(3) Includes the $416.3 million acquisition date fair value of the potential earn-out payments.
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, 2018 Compared to Three Months Ended September 30, 2017

The increase in commodity sales reflects increased NGL, natural gas, condensate and petroleum volumes ($538.4 million) and higher NGL and condensate prices ($475.5 million), partially offset by lower natural gas prices ($127.5 million) and the impact of hedges ($21.4 million). Fee-based and other revenues increased primarily due to higher gas processing and crude gathering fees.

The increase in product purchases reflects increased volumes and higher NGL and condensate prices.

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($84.6 million) and lower fee revenue ($5.8 million) with a corresponding net reduction in product purchases, resulting in no impact on operating margin or gross margin.

The higher operating margin and gross margin in 2018 reflect increased segment margin results for Gathering and Processing and Logistics and Marketing. Additionally, the Company's operating margin for the three months ended September 30, 2017 was reduced by approximately $10 million due to temporary operational issues related to the impact of Hurricane Harvey. Operating expenses increased compared to 2017 primarily due to system expansions and higher activity levels. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense was flat as higher depreciation related to the Company's growth investments was offset by lower depreciation for the Company's North Texas system and lower scheduled amortization of Badlands intangibles. Lower North Texas system depreciation reflects the impact of a partial impairment of property, plant and equipment recorded in the third quarter of 2017.

General and administrative expense increased primarily due to higher compensation and benefits and higher outside professional services.

Other operating (income) expense in 2018 was comprised primarily of the estimated loss on the Company's refined products and crude oil storage and terminaling facilities in Tacoma, Washington, and Baltimore, Maryland that were held for sale as of September 30, 2018.

Interest expense, net, increased due to the impact of higher average borrowings and lower interest income on the mandatorily redeemable preferred interest valuations, partially offset by higher capitalized interest related to the Company's major growth investments.

Equity earnings increased in 2018, primarily reflecting increased earnings at Gulf Coast Fractionators LP ("GCF") and commencement of operations at the Cayenne Pipeline joint venture ("Cayenne").

During 2018, the Company recorded expense of $16.6 million resulting primarily from an increase in fair value as of September 30, 2018 of the Permian Acquisition contingent consideration liability. The fair value increase in 2018 was primarily attributable to a shorter discount period. During 2017, the Company recorded income of $126.8 million resulting from a decrease in the fair value of the contingent consideration liability from June 30, 2017 to September 30, 2017. The fair value decrease in 2017 reflected reductions in actual and forecasted volumes and gross margin resulting from changes in producers' drilling activity in the region.

The Company recorded a lower income tax benefit in 2018 than in 2017. The decrease is primarily attributable to the difference in income (loss) before taxes between the periods, the reduced statutory rate, and the difference in methods required by the interim tax accounting rules. In 2018, the Company determined income tax expense (benefit) using the estimated annual effective tax rate. However, in 2017, the application of interim tax accounting rules required the Company to use the then statutory tax rate for the nine-month period ended September 30, 2017 and the six-month period ended June 30, 2017. Furthermore, the Tax Cut and Jobs Act reduced the Federal statutory rate from 35% in 2017 to 21% in 2018.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

The increase in commodity sales reflects increased NGL, natural gas, petroleum and condensate volumes ($1,241.7 million) and higher NGL and condensate prices ($1,097.5 million), partially offset by lower natural gas prices ($389.2 million) and the impact of hedges ($68.7 million). Fee-based and other revenues increased primarily due to higher gas processing and crude gathering fees.

The increase in product purchases reflects increased volumes and higher NGL and condensate prices.

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($250.6 million) and lower fee revenue ($18.6 million) with a corresponding net reduction in product purchases, resulting in no impact on operating margin or gross margin.

The higher operating margin and gross margin in 2018 reflect increased segment margin results for Gathering and Processing and Logistics and Marketing. Additionally, the Company's operating margin for the nine months ended September 30, 2017 was reduced by approximately $10 million due to temporary operational issues related to the impact of Hurricane Harvey. Operating expenses increased compared to 2017 primarily due to system expansions, higher activity levels and the inclusion of the Permian Acquisition for nine months in 2018 as compared with seven months in 2017. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense was flat as higher depreciation related to the Company's growth investments was offset by lower depreciation for the Company's North Texas system, lower scheduled amortization of Badlands intangibles and lower depreciation on the Company's inland marine barge business sold in the second quarter of 2018. In 2017, the Company recorded a partial impairment of property, plant and equipment in the Company's North Texas system.

General and administrative expense increased primarily due to higher compensation and benefits and higher outside professional services.

Other operating (income) expense in 2018 was comprised primarily of the estimated loss on the Company's refined products and crude oil storage and terminaling facilities in Tacoma, Washington, and Baltimore, Maryland, that were held for sale as of September 30, 2018, partially offset by the gain on sale of the Company’s inland marine barge business. In 2017, other operating (income) expense included the loss on sale of the Company’s 100% ownership interest in the Venice Gathering System.

Lower interest expense, net, in 2018 was primarily due to higher non-cash interest income related to a decrease in the mandatorily redeemable preferred interests liability and higher capitalized interest related to the Company's major growth investments. These factors more than offset the impact of higher average outstanding borrowings during 2018. The mandatorily redeemable preferred interests liability is revalued quarterly at the estimated redemption value as of the reporting date, and the decrease in 2018 of its estimated redemption value is primarily attributable to the February 2018 amendments to the agreements governing the WestTX and WestOK joint ventures.

Equity earnings increased in 2018, which reflects decreased losses of the T2 Joint Ventures, which in 2017 included a $12.0 million loss provision due to the impairment of the Company’s investment in the T2 EF Cogen joint venture, increased earnings at GCF and the commencement of operations at Cayenne.

In 2018, the Company recorded a loss from financing activities of $2.0 million associated with amendments to the Company’s revolving credit facilities, which resulted in a write-off of debt issuance costs. In 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.

During 2018, the Company recorded expense of $12.1 million resulting from the change in the fair value of contingent considerations, substantially all of which was due to the increase in fair value as of September 30, 2018 of the Permian Acquisition contingent consideration liability described above. During 2017, the Company recorded income of $125.6 million resulting from a decrease in the fair value of the Permian Acquisition contingent consideration liability from the acquisition date to September 30, 2017.

During 2018, the Company recorded income tax expense, whereas in 2017 the Company recorded an income tax benefit. Similar to the quarterly results, the change is primarily attributable to the difference in income (loss) before taxes between the periods, the reduced federal statutory rate from 2017 to 2018 and the difference in methods required by the interim tax accounting rules. As described above in the quarterly results, the Company utilized the estimated annual effective tax rate in 2018, whereas in 2017 the Company used the then statutory rate of 37.3% due to the loss limitation rule under interim period income tax accounting.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at the Company’s consolidated Carnero joint venture and Cedar Bayou Fractionators.

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 (including the Midland and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including exposure to the SCOOP and STACK plays) 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:

	Three Months Ended September 30,				**Nine Months Ended September 30,**			
	2018	**2017**	**2018 vs. 2017**		**2018**	**2017**	**2018 vs. 2017**	
Gross margin	$ 373.7	$ 289.7	$ 84.0	29 %	$ 1,046.3	$ 817.1	$ 229.2	28 %
Operating expenses	118.4	91.4	27.0	30 %	327.9	267.8	60.1	22 %
Operating margin	$ 255.3	$ 198.3	$ 57.0	29 %	$ 718.4	$ 549.3	$ 169.1	31 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Permian Midland (4)	1,161.7	932.1	229.6	25 %	1,100.8	864.9	235.9	27 %
Permian Delaware (4)	470.5	403.9	66.6	16 %	432.5	373.6	58.9	16 %
Total Permian	1,632.2	1,336.0	296.2		1,533.3	1,238.5	294.8	
SouthTX	364.1	330.1	34.0	10 %	397.8	242.1	155.7	64 %
North Texas	247.6	261.8	(14.2)	(5 %)	243.0	273.7	(30.7)	(11 %)
SouthOK	568.2	515.2	53.0	10 %	549.4	478.5	70.9	15 %
WestOK	353.9	367.1	(13.2)	(4 %)	350.8	382.5	(31.7)	(8 %)
Total Central	1,533.8	1,474.2	59.6		1,541.0	1,376.8	164.2	
Badlands (5)	90.5	60.9	29.6	49 %	83.3	53.1	30.2	57 %

Total Field	3,256.5	2,871.1	385.4		3,157.6	2,668.4	489.2	
Coastal	783.3	750.5	32.8	4%	724.5	750.1	(25.6)	(3%)
Total	4,039.8	3,621.6	418.2	12%	3,882.1	3,418.5	463.6	14%
NGL production, MBbl/d (3)								
Permian Midland (4)	152.2	122.8	29.4	24%	148.0	111.8	36.2	32%
Permian Delaware (4)	58.9	46.3	12.6	27%	51.6	42.4	9.2	22%
Total Permian	211.1	169.1	42.0		199.6	154.2	45.4	
SouthTX	49.0	35.4	13.6	38%	52.5	25.2	27.3	108%
North Texas	29.6	29.3	0.3	1%	28.1	30.8	(2.7)	(9%)
SouthOK	61.2	42.7	18.5	43%	53.8	40.7	13.1	32%
WestOK	20.7	20.7	-	-	19.9	22.3	(2.4)	(11%)
Total Central	160.5	128.1	32.4		154.3	119.0	35.3	
Badlands	10.5	9.0	1.5	17%	10.5	7.4	3.1	42%
Total Field	382.1	306.2	75.9		364.4	280.6	83.8	
Coastal	47.3	40.0	7.3	18%	42.8	38.2	4.6	12%
Total	429.4	346.2	83.2	24%	407.2	318.8	88.4	28%
Crude oil gathered, Badlands, MBbl/d	161.7	108.7	53.0	49%	139.9	111.6	28.3	25%
Crude oil gathered, Permian, MBbl/d (4)	75.1	35.7	39.4	110%	63.8	24.6	39.2	159%
Natural gas sales, BBtu/d (3)	1,817.6	1,738.5	79.1	5%	1,821.1	1,647.8	173.3	11%
NGL sales, MBbl/d	329.6	244.4	85.2	35%	311.3	240.4	70.9	29%
Condensate sales, MBbl/d	12.6	11.4	1.2	11%	12.8	11.4	1.4	12%
Average realized prices (6):								
Natural gas, $/MMBtu	1.93	2.58	(0.66)	(26%)	2.03	2.71	(0.68)	(25%)
NGL, $/gal	0.75	0.56	0.19	34%	0.67	0.51	0.16	31%
Condensate, $/Bbl	58.31	42.69	15.62	37%	58.49	43.42	15.07	35%

(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 Permian Midland and New Delaware volumes are included within Permian Delaware. 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, 2018 Compared to Three Months Ended September 30, 2017

The increase in gross margin was primarily due to higher Permian, Central and Badlands volumes and higher NGL and condensate prices, partially offset by lower natural gas prices. The increase in Field Gathering and Processing inlet volumes included both areas in the Permian region, SouthTX, SouthOK and Badlands, partially offset by decreases at WestOK and North Texas. NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased NGL production, including additional ethane recoveries. Prior year NGL sales were unfavorably impacted by temporary operational issues related to Hurricane Harvey in the third quarter of 2017. Coastal Gathering and Processing gross margin increased due to higher inlet volumes, richer gas, increased recoveries and higher NGL prices. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to production from new wells and system expansions. Total crude oil gathered volumes increased in the Permian region due to production from new wells.

Operating expenses in the Permian region increased primarily as a result of higher compensation, contract labor, and other costs associated with plant expansions.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

The increase in gross margin was primarily due to higher Permian volumes including those associated with the Permian Acquisition in March 2017, higher Central and Badlands volumes and higher NGL and condensate prices, partially offset by lower natural gas prices. The overall increase in Field Gathering and Processing inlet volumes included both areas of the Permian region, SouthTX, SouthOK and Badlands, partially offset by decreases at WestOK and North Texas. NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased NGL production, including additional ethane recoveries. Prior year NGL sales were unfavorably impacted by temporary operational issues related to Hurricane Harvey in the third quarter of 2017. Coastal Gathering and Processing gross margin increased due to richer gas, increased recoveries and higher NGL prices. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to production from new wells and system expansions. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition and production from new wells and system expansions.

Operating expenses in the Permian region increased primarily as a result of higher compensation, contract labor, and other costs associated with plant expansions as well as the inclusion of the March 2017 Permian Acquisition for the full period of 2018.

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:

	Three Months Ended September 30, 2018				
Operating statistics:					
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**		**Net Volume (3)**	**Actual Reported**
Permian Midland	1,466.9	Varies (4)		1,161.7	1,161.7
Permian Delaware	470.5	100	%	470.5	470.5
Total Permian	1,937.4			1,632.2	1,632.2
SouthTX	364.1	Varies (5)		272.1	364.1
North Texas	247.6	100	%	247.6	247.6
SouthOK	568.2	Varies (6)		454.6	568.2
WestOK	353.9	100	%	353.9	353.9
Total Central	1,533.8			1,328.2	1,533.8
Badlands (7)	90.5	100	%	90.5	90.5
Total Field	3,561.7			3,050.9	3,256.5
NGL production, MBbl/d (2)					
Permian Midland	193.3	Varies (4)		152.2	152.2
Permian Delaware	58.9	100	%	58.9	58.9
Total Permian	252.2			211.1	211.1
SouthTX	49.0	Varies (5)		35.5	49.0
North Texas	29.6	100	%	29.6	29.6
SouthOK	61.2	Varies (6)		48.3	61.2
WestOK	20.7	100	%	20.7	20.7
Total Central	160.5			134.1	160.5
Badlands	10.5	100	%	10.5	10.5
Total Field	423.2			355.7	382.1

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(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, other than Badlands.
(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) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company’s reported financials.
(5) SouthTX includes the Raptor Plant and Silver Oak II Plant, both of which the Company owns a 50% interest through the Carnero Joint Venture. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in the Company’s reported financials.
(6) SouthOK includes the Centrahoma Joint Venture, of which the Company owns 60%, and other plants that are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company’s reported financials.
(7) Badlands natural gas inlet represents the total wellhead gathered volume.

	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**
Permian Midland (4)	1,159.1	Varies (5)		932.1	932.1
Permian Delaware (4)	403.9	100	%	403.9	403.9

Total Permian	1,563.0			1,336.0	1,336.0
SouthTX	330.1	Varies (6)		260.0	330.1
North Texas	261.8	100	%	261.8	261.8
SouthOK	515.2	Varies (7)		412.1	515.2
WestOK	367.1	100	%	367.1	367.1
Total Central	1,474.2			1,301.0	1,474.2
Badlands (8)	60.9	100	%	60.9	60.9
Total Field	3,098.1			2,697.9	2,871.1
NGL production, MBbl/d (2)					
Permian Midland (4)	154.2	Varies (5)		122.8	122.8
Permian Delaware (4)	46.3	100	%	46.3	46.3
Total Permian	200.5			169.1	169.1
SouthTX	35.4	Varies (6)		28.6	35.4
North Texas	29.3	100	%	29.3	29.3
SouthOK	42.7	Varies (7)		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, other than Badlands.
(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 Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.
(6) SouthTX includes the Raptor Plant, which began operations in the second quarter of 2017, of which the Company owns a 50% interest through the Carnero Joint Venture. SouthTX also 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 owned a 100% interest until it was contributed to the Carnero Joint Venture. The Carnero Joint Venture is 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 that are owned 100% by us. 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 the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as storing, fractionating, terminaling, transporting and marketing of NGLs and NGL products, including services to liquefied petroleum gas ("LPG") exporters; storing 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. The Logistics and Marketing segment includes Grand Prix, which is currently under construction. The associated assets, including these pipeline projects, are generally connected to and supplied in part by the Company's Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

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

	Three Months Ended September 30,				**Nine Months Ended September 30,**			
	2018	**2017**	**2018 vs. 2017**		**2018**	**2017**	**2018 vs. 2017**	
	(In millions)							
Gross margin	$ 249.4	$ 180.0	$ 69.4	39 %	$ 653.1	$ 553.3	$ 99.8	18 %
Operating expenses	75.9	64.1	11.8	18 %	211.4	194.8	16.6	9 %
Operating margin	$ 173.5	$ 115.9	$ 57.6	50 %	$ 441.7	$ 358.5	$ 83.2	23 %
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	454.5	329.3	125.2	38 %	419.0	324.3	94.7	29 %
LSNG treating volumes (2)	36.3	27.2	9.1	33 %	33.4	31.6	1.9	6 %
Benzene treating volumes (2)	—	16.1	(16.1)	(100 %)	4.4	20.5	(16.2)	(79 %)
Export volumes (4)	208.2	154.5	53.6	35 %	200.2	175.5	24.6	14 %

NGL sales	555.7	463.4	92.3	20 %	526.7	468.1	58.6	13 %
Average realized prices:								
NGL realized price, $/gal	$ 0.88	$ 0.67	$ 0.21	31 %	$ 0.80	$ 0.64	$ 0.16	25 %

(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 quarter and the denominator is the number of calendar days during the quarter.
(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components that 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, 2018 Compared to Three Months Ended September 30, 2017

Logistics and Marketing gross margin increased primarily due to higher fractionation margin and higher LPG export margin. Fractionation margin increased due to higher supply volume and higher fees, partially offset by lower system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power that are largely reflected in operating expenses (see footnote (2) above). LPG export margin increased primarily due to higher volumes. Prior year fractionation supply volume and LPG export volumes were unfavorably impacted by temporary operational issues related to Hurricane Harvey. Other contributors to gross margin included higher treating margin, higher marketing gains and higher terminal and storage throughput.

Operating expenses increased due to higher fuel and power costs that are largely passed through, higher compensation and benefits and higher ad valorem taxes.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Logistics and Marketing gross margin increased primarily due to higher fractionation margin. Fractionation margin increased due to higher supply volume. Fractionation margin was partially impacted by the variable effects of fuel and power that are largely reflected in operating expenses (see footnote (2) above). Prior year fractionation supply volume was unfavorably impacted by temporary operational issues related to Hurricane Harvey. Other contributors to gross margin included higher marketing gains, higher terminal and storage throughput and higher domestic marketing margin.

Operating expenses increased due to higher compensation and benefits, higher fuel and power costs that are largely passed through and higher ad valorem taxes, partially offset by lower maintenance.

Other

	Three Months Ended September 30,			**Nine Months Ended September 30,**		
	2018	**2017**	**2018 vs. 2017**	**2018**	**2017**	**2018 vs. 2017**
	(In millions)					
Gross margin	$ (20.8)	$ (1.0)	$ (19.8)	$ (42.2)	$ 3.9	$ (46.1)
Operating margin	$ (20.8)	$ (1.0)	$ (19.8)	$ (42.2)	$ 3.9	$ (46.1)

Other contains the results 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 the Company's 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, 2018			**Three Months Ended September 30, 2017**		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	**Price Spread (1)**	**Gain (Loss)**	**Volume Settled**	**Price Spread (1)**	**Gain (Loss)**
Natural gas (BBtu)	15.7	$ 0.82	$ 12.9	17.3	$ 0.23	$ 4.0
NGL (MMgal)	99.0	(0.27)	(26.4)	74.8	(0.09)	(6.7)
Crude oil (MBbl)	0.5	(15.81)	(8.1)	0.4	6.29	2.3
Non-hedge accounting (2)			0.8			(0.6)
Ineffectiveness (3)			—			—
			$ (20.8)			$ (1.0)

	Nine Months Ended September 30, 2018	**Nine Months Ended September 30, 2017**
	(In millions, except volumetric data and price amounts)	

	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	48.6	$ 0.74	$ 35.8	43.3	$ 0.15	$ 6.6
NGL (MMgal)	286.3	(0.17)	(49.7)	177.5	(0.04)	(7.7)
Crude oil (MBbl)	1.5	(13.10)	(20.0)	0.9	6.29	5.8
Non-hedge accounting (2)			(8.3)			(0.9)
Ineffectiveness (3)			—			0.1
			$ (42.2)			$ 3.9

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(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) Effective upon the adoption of ASU 2017-12 on January 1, 2018, the Company is no longer required to recognize ineffectiveness through operating margin. Prior to the Company's adoption of ASU 2017-12, ineffectiveness primarily related to certain crude hedging contracts and certain acquired hedges of Targa Pipeline Partners, L.P. ("TPL") that did 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. The final settlement was received in December 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, terminaling and selling crude oil; and storing, terminaling, and selling refined petroleum products.

For more information, please visit the Company's 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 following tables 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) attributable to TRC before interest, income taxes, depreciation and amortization, and other items that the Company believes should be adjusted consistent with the Company's core operating performance. The adjusting items are detailed in the Adjusted EBITDA reconciliation table and its footnotes. Adjusted EBITDA is used as a supplemental financial measure by the Company and by external users of its 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, its 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, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ (23.7)	$ (167.6)	$ 108.2	$ (229.3)
Income attributable to TRP preferred limited partners	2.8	2.8	8.4	8.4
Interest (income) expense, net (1)	78.2	56.1	124.2	181.2
Income tax expense (benefit)	(3.9)	(97.4)	37.7	(132.3)
Depreciation and amortization expense	206.3	208.3	607.1	602.8
Impairment of property, plant and equipment	—	378.0	—	378.0
(Gain) loss on sale or disposition of assets	61.1	0.3	14.3	16.6
(Gain) loss from financing activities (2)	—	—	2.0	16.5
(Earnings) loss from unconsolidated affiliates	(3.0)	(0.2)	(6.4)	16.6
Distributions from unconsolidated affiliates and preferred partner interests, net	7.5	4.6	21.4	15.0
Change in contingent considerations	16.6	(126.8)	12.1	(125.6)
Compensation on equity grants	13.8	10.2	40.7	31.7
Transaction costs related to business acquisitions	—	0.4	—	5.6
Splitter Agreement (3)	10.8	10.8	32.3	32.3
Risk management activities (4)	(0.8)	2.0	8.3	7.2
Noncontrolling interests adjustments (5)	(7.7)	(5.0)	(19.7)	(13.6)
TRC Adjusted EBITDA	**$ 358.0**	**$ 276.5**	**$ 990.6**	**$ 811.1**
Distributions to TRP preferred limited partners	(2.8)	(2.8)	(8.4)	(8.4)
Splitter Agreement (3)	32.3	(10.8)	10.8	(32.3)
Interest expense on debt obligations (6)	(67.5)	(52.8)	(185.7)	(168.5)
Cash tax (expense) benefit (7)	—	—	—	46.7
Maintenance capital expenditures	(33.3)	(24.0)	(80.4)	(73.0)
Noncontrolling interests adjustments of maintenance capital expenditures	0.5	0.5	1.6	1.1
Distributable Cash Flow	**$ 287.2**	**$ 186.6**	**$ 728.5**	**$ 576.7**

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(1) Includes the change in estimated redemption value of the mandatorily redeemable preferred interests.
(2) Gains or losses on debt repurchases, amendments, exchanges or early debt extinguishments.
(3) 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.
(4) Risk management activities related to derivative instruments including the cash impact of hedges acquired in the 2015 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. The cash impact of the acquired hedges ended in December 2017.
(5) Noncontrolling interest portion of depreciation and amortization expense.
(6) Excludes amortization in interest expense.
(7) 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. The remaining $20.9 million unamortized balance of the tax refund was therefore included in Distributable Cash Flow in the second quarter of 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 fees 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 fees (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 the Company's equity volumes 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 of the Company to operating margin and gross margin for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ (23.7)	$ (167.6)	$ 108.2	$ (229.3)
Net income (loss) attributable to noncontrolling interests	12.5	12.5	40.4	34.3
Net income (loss)	(11.2)	(155.1)	148.6	(195.0)
Depreciation and amortization expense	206.3	208.3	607.1	602.8
General and administrative expense	63.2	49.9	176.9	149.5
Impairment of property, plant and equipment	—	378.0	—	378.0
Interest expense, net	78.2	56.1	124.2	181.2
Income tax expense (benefit)	(3.9)	(97.4)	37.7	(132.3)
(Gain) loss on sale or disposition of assets	61.1	0.3	14.3	16.6
(Gain) loss from financing activities	—	—	2.0	16.5
Other, net	14.3	(126.9)	7.1	(105.7)
Operating margin	408.0	313.2	1,117.9	911.6
Operating expenses	194.9	155.5	538.7	462.7
Gross margin	**$ 602.9**	**$ 468.7**	**$ 1,656.6**	**$ 1,374.3**

Forward-Looking Statements

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, 2017, 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.

Contact the Company's investor relations department by email at InvestorRelations@targaresources.com or by phone at (713) 584-1133.

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Source: Targa Resources Corp.