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Targa Resources Corp. Reports
Fourth Quarter and Full Year 2018 Financial Results and Provides 2019 Operational and Financial Guidance

HOUSTON – February 20, 2019 - Targa Resources Corp. (NYSE: TRGP) ("TRC", the "Company" or "Targa") today reported fourth quarter and full year 2018 results.

Fourth Quarter and Full Year 2018 Financial Results

Fourth quarter 2018 net income (loss) attributable to Targa Resources Corp. was ($106.4) million compared to $283.1 million for the fourth quarter of 2017. The fourth quarter of 2018 included a pre-tax non-cash loss of $210.0 million from the impairment of goodwill. For the full year 2018, net income attributable to Targa Resources Corp. was $1.6 million compared to $54.0 million for 2017.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $375.8 million for the fourth quarter of 2018 compared to $328.4 million for the fourth quarter of 2017. For the full year 2018, Adjusted EBITDA was $1,366.3 million compared to $1,139.8 million for 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")).

"The strength of our execution and performance during 2018 drove record Adjusted EBITDA, providing Targa with positive momentum for 2019 and beyond," said Joe Bob Perkins, Chief Executive Officer of the Company. "Key projects are coming online for us in 2019, including additional Gathering and Processing facilities, another fractionator in Mont Belvieu, Texas, and our Grand Prix NGL Pipeline, which will connect much of our G&P NGL supply to Mont Belvieu. These projects are all expected to be highly utilized as we continue to support the needs of our customers, and will drive increasing, largely fee-based, cash flow growth for Targa. We remain focused on execution to enhance our already attractive long-term outlook."

On January 17, 2019, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended December 31, 2018, or $3.64 per share on an annualized basis. Total cash dividends of approximately $211.2 million were paid on February 15, 2019 on all outstanding shares of common stock to holders of record as of the close of business on January 31, 2019. Also on January 17, 2019, 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 were paid on February 14, 2019 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on January 31, 2019.

The Company reported distributable cash flow for the fourth quarter of 2018 of $214.0 million compared to total common dividends to be paid of $211.2 million and total Series A Preferred Stock dividends to be paid of $22.9 million. For the full year 2018, distributable cash flow of $942.4 million resulted in dividend coverage over 1.0 times on the common and Series A Preferred Stock dividends paid with respect to 2018.

Capitalization and Liquidity

The Company's total consolidated debt as of December 31, 2018 was $6,660.3 million including $435.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility. The consolidated debt included $6,225.3 million of Targa Resources Partners LP ("TRP" or "the Partnership") debt, net of $32.6 million of debt issuance costs, with $700.0 million outstanding under TRP's $2.2 billion senior secured revolving credit facility, $280.0 million outstanding under TRP's accounts receivable securitization facility and $5,277.9 million of outstanding TRP senior notes, net of unamortized premiums.

Total consolidated liquidity of the Company as of December 31, 2018, including $232.1 million of cash, was over $1.9 billion. As of December 31, 2018, TRC had available borrowing capacity under its senior secured revolving credit facility of $235.0 million. TRP had $79.5 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 $1,420.5 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.

Financing Update

During the three months ended December 31, 2018, the Company issued 2,467,085 shares of common stock under its equity distribution agreements ("EDAs"), resulting in total net proceeds of $111.5 million. For the year ended December 31, 2018, TRC issued a total of 13,843,613 shares of common stock under its EDAs, resulting in total net proceeds of $683.5 million.

On December 7, 2018, TRC amended and extended the Partnership's accounts receivable securitization facility to increase the facility size from $350.0 million to $400.0 million and extend the maturity date to December 6, 2019.

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,488.8 million. The net proceeds from the offerings were used to redeem in full the Partnership's outstanding senior notes due 2019 and the remainder is expected to be used for general partnership purposes, which may include repaying borrowings under its credit facilities or other indebtedness, funding growth investments and acquisitions, and working capital.

In February 2019, the Company entered into definitive agreements to sell a 45 percent interest in Targa Badlands LLC ("Badlands"), the entity that holds all of the Company's assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities (collectively, "Blackstone") for $1.6 billion in cash.

The Company expects to use the net cash proceeds to pay down debt and for general corporate purposes including funding its growth capital program. The transaction is expected to close in the second quarter of 2019 and is subject to customary regulatory approvals and closing conditions.

2019 Financial and Operational Expectations

For 2019, assuming NGL composite barrel prices average $0.60 per gallon, crude oil prices average $54 per barrel and natural gas prices average $3.00 per MMbtu for the year, and pro forma for its recently announced transaction to sell a 45 percent interest in the Badlands, Targa estimates full year Adjusted EBITDA to be between $1,300 million and $1,400 million.

Targa estimates 2019 net growth capital expenditures to be approximately $2.3 billion, based on currently announced projects and other identified spending. Net maintenance capital expenditures for 2019 are estimated to be approximately $130 million.

Targa estimates that 2019 Field Gathering and Processing ("G&P") natural gas inlet volumes will average between 3,450 million cubic feet per day ("MMcf/d") and 3,650 MMcf/d, with the midpoint representing a 10 percent increase over 2018 Field G&P average natural gas inlet volumes. In the Permian Basin, Targa estimates average G&P natural gas inlet volumes will be between 1,850 MMcf/d and 1,950 MMcf/d, with the midpoint representing a 20 percent increase over 2018 Permian G&P average natural gas inlet volumes. In the Badlands and SouthOK, Targa estimates 2019 average natural gas inlet volumes will be higher than average 2018 volumes, and Targa also estimates higher average crude gathered volumes in both the Badlands and Permian year over year. Targa estimates that these volume increases will be partially offset by lower volumes in WestOK, SouthTX and North Texas.

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 February 20, 2019 to discuss fourth quarter 2018 results and its 2019 operational and financial outlook. 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/ui7iq2dg or by dialing 877-881-2598. The conference ID number for the dial-in is 2176547. 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 December 31, 2018	Three Months Ended December 31, 2017	2018 vs. 2017		Year Ended December 31, 2018	Year Ended December 31, 2017	2018 vs. 2017	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 2,297.4	$ 2,398.0	$ (100.6)	(4%)	$ 9,278.7	$ 7,751.1	$ 1,527.6	20%
Fees from midstream services	300.4	304.8	(4.4)	(1%)	1,205.3	1,063.8	141.5	13%
Total revenues	2,597.8	2,702.8	(105.0)	(4%)	10,484.0	8,814.9	1,669.1	19%
Product purchases	2,008.6	2,168.2	(159.8)	(7%)	8,238.2	6,906.1	1,332.1	19%
Gross margin (1)	589.2	534.6	54.6	10%	2,245.8	1,908.8	337.0	18%
Operating expenses	183.3	160.2	23.1	14%	722.0	622.9	99.1	16%
Operating margin (1)	405.9	374.4	31.5	8%	1,523.8	1,285.9	237.9	19%
Depreciation and amortization expense	208.7	206.7	2.0	1%	815.9	809.5	6.4	1%
General and administrative expense	80.0	54.0	26.0	48%	256.9	203.4	53.5	26%
Impairment of property, plant and equipment	—	—	—	—	—	378.0	(378.0)	(100%)
Impairment of goodwill	210.0	—	210.0	—	210.0	—	210.0	—
Other operating (income) expense	(12.2)	0.2	(12.4)	NM	3.5	17.4	(13.9)	(80%)
Income (loss) from operations	(80.6)	113.5	(194.1)	(171%)	237.5	(122.4)	359.9	294%
Interest expense, net	(61.6)	(52.4)	(9.2)	(18%)	(185.8)	(233.7)	47.9	20%
Equity earnings (loss)	0.9	(0.3)	1.2	NM	7.3	(17.0)	24.3	143%
Gain (loss) from financing activities	—	(0.3)	0.3	100%	(2.0)	(16.8)	14.8	88%
Change in contingent considerations	20.9	(26.0)	46.9	180%	8.8	99.6	(90.8)	(91%)
Other income (expense), net	0.1	(0.1)	0.2	200%	0.1	(2.6)	2.7	104%
Income tax (expense) benefit	32.3	264.8	(232.5)	(88%)	(5.5)	397.1	(402.6)	(101%)
Net income (loss)	(88.0)	299.2	(387.2)	(129%)	60.4	104.2	(43.8)	(42%)
Less: Net income (loss) attributable to noncontrolling interests	18.4	16.1	2.3	14%	58.8	50.2	8.6	17%
Net income (loss) attributable to Targa Resources Corp.	(106.4)	283.1	(389.5)	(138%)	1.6	54.0	(52.4)	(97%)
Dividends on Series A Preferred Stock	22.9	22.9	—	—	91.7	91.7	—	—
Deemed dividends on Series A Preferred Stock	7.7	6.7	1.0	15%	29.2	25.7	3.5	14%
Net income (loss) attributable to common shareholders	$ (137.0)	$ 253.5	$ (390.5)	(154%)	$ (119.3)	$ (63.4)	$ (55.9)	(88%)
Financial data:								
Adjusted EBITDA (1)	$ 375.8	$ 328.4	$ 47.4	14%	$ 1,366.3	$ 1,139.8	$ 226.5	20%
Distributable cash flow (1)	214.0	274.6	(60.6)	(22%)	942.4	851.8	90.6	11%
Capital expenditures (2)	1,017.3	518.9	498.4	96%	3,327.7	1,506.5	1,821.2	121%
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 $2,740.7 million, and $1,441.5 million for the years ended December 31, 2018 and 2017, and $624.2 million and $518.8 million for the three months ended December 31, 2018 and 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 December 31, 2018 Compared to Three Months Ended December 31, 2017

The decrease in commodity sales reflects lower NGL, natural gas and condensate prices ($405.7 million) and decreased petroleum volumes ($17.2 million), partially offset by increased NGL, condensate and natural gas volumes ($358.0 million) and the impact of hedges ($46.2 million). Fee-based and other revenues were relatively flat.

The decrease in product purchases was primarily due to lower commodity prices and the effect of prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018, partially offset by increased volumes.

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($82.6 million) and lower fee revenue ($21.0 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 results for the Gathering and Processing 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 due to higher depreciation related to the Company's growth investments, partially offset by lower scheduled amortization of Badlands intangibles and lower depreciation due to asset sales in 2018.

General and administrative expense increased primarily due to higher compensation and benefits, including increased staffing levels, and higher outside professional services.

In conjunction with the Company's required annual goodwill assessments, the Company recognized impairments of goodwill totaling $210.0 million during 2018 related to the remaining goodwill from the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively the "Atlas mergers"). There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Other operating (income) expense in 2018 was comprised primarily of the gain on an exchange of a portion of the Company's Versado gathering system, partially offset by the loss on disposal of the benzene saturation component of the Company's LSNG hydrotreater and the loss for abandoned project development costs. There was no such activity in 2017.

Higher interest expense, net, in 2018 was primarily due to higher average outstanding borrowings and higher average interest rates during 2018, partially offset by higher capitalized interest related to the Company's major growth investments.

During 2018, the Company recorded other income of $20.9 million primarily related to decreases in the fair value of the Permian Acquisition contingent consideration liability. During 2017, the Company recorded other expense of $26.0 million primarily related to increases in the fair value of the Permian Acquisition contingent consideration liability.

The decrease in the income tax benefit in 2018 is primarily due to the recalculation of deferred balances as a result of the Tax Cuts and Jobs Act of 2017 (the "Tax Act"), which reduced the corporate tax rate from 35% to 21%. The benefit of the rate reduction was included in the 2017 income tax benefit.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at the Company's consolidated Centrahoma joint venture.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The increase in commodity sales reflects increased NGL, natural gas, petroleum and condensate volumes ($1,606.0 million) and higher NGL and condensate prices ($742.2 million), partially offset by lower natural gas prices ($465.7 million) and the impact of hedges ($22.4 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 ($333.2 million) and lower fee revenue ($39.6 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 results for both Gathering and Processing and Logistics and Marketing. 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 due to higher depreciation related to the Company's growth investments, partially offset by lower depreciation for the Company's North Texas system, which incurred an impairment write-down in 2017, lower scheduled amortization of Badlands intangibles and lower depreciation on the Company's inland marine barge business sold in the second quarter of 2018.

General and administrative expense increased primarily due to higher compensation and benefits, including increased staffing levels, legal costs, outside professional services and contract labor costs.

In conjunction with the Company's required annual goodwill assessments, the Company recognized impairments of goodwill totaling $210.0 million during 2018 related to the remaining goodwill from the Atlas mergers. There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Other operating (income) expense in 2018 was comprised primarily of the loss on sale of the Company's refined products and crude oil storage and terminaling facilities in Tacoma, Washington, and Baltimore, Maryland, the loss on disposal of the benzene saturation component of the Company's LSNG hydrotreater and the loss for abandoned project development costs, partially offset by the gain on sale of the Company's inland marine barge business and the gain on an exchange of a portion of the Company's Versado gathering system. 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 lower valuation of 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.

Equity earnings increased in 2018 primarily due to decreased losses of the T2 Joint Ventures, increased earnings resulting from the commencement of operations at Cayenne and increased earnings at Gulf Coast Fractionators. Equity losses of the T2 Joint Ventures in 2017 included a $12.0 million impairment of the Company's investment in the T2 EF Cogen joint venture.

In 2018, the Company recorded a loss from financing activities of $2.0 million associated with amendments of 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 $16.8 million upon the redemption of the Partnership's outstanding 6⅜% Senior Notes and the repayment of the outstanding balance on the Company's senior secured term loan.

During 2018, other income included $8.8 million of fair value adjustments of the Permian Acquisition contingent consideration, as compared to $99.6 million of other income in 2017. The decrease in fair value of the contingent consideration in 2018 was primarily attributable to lower forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period. The decrease in fair value of the contingent consideration in 2017 was primarily related to reductions in forecasted volumes and gross margin as a result of changes in producers' drilling activity in the region.

During 2018, the Company recorded income tax expense, whereas in 2017 the Company recorded an income tax benefit. The change is primarily attributable to the difference in income (loss) before taxes between the periods and the reduced federal statutory rate from 2017 to 2018. In 2017, the income tax benefit was primarily due to the Tax Act and the resulting reduction of the federal corporate tax rate from 35% to 21%, which under GAAP results in a recalculation of the Company's ending balance sheet deferred tax balances.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at the Company's consolidated Carnero and Centrahoma joint ventures, Cedar Bayou Fractionators and Venice Energy Services Company, L.L.C.

Review of Segment Performance

The following discussion of segment performance includes inter-segment activities. The Company views segment operating margin and gross margin as important performance measures of the core profitability of its operations. These measures are key components of internal financial reporting and are reviewed for consistency and trend analysis. For a discussion of operating margin and gross margin, see "Targa Resources Corp. - Non-GAAP Financial Measures - Operating Margin and Gross 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 the SCOOP and STACK plays) and South Central Kansas; the Williston Basin in North Dakota; and 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 December 31, 2018	Three Months Ended December 31, 2017	2018 vs. 2017		Year Ended December 31, 2018	Year Ended December 31, 2017	2018 vs. 2017	
Gross margin	$ 360.4	$ 328.1	$ 32.3	10%	$ 1,406.7	$ 1,145.5	$ 261.2	23%
Operating expenses	110.4	93.7	16.7	18%	438.3	361.7	76.6	21%
Operating margin	$ 250.0	$ 234.4	$ 15.6	7%	$ 968.4	$ 783.8	$ 184.6	24%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Permian Midland (4)	1,260.7	978.4	282.3	29%	1,141.2	893.5	247.7	28%
Permian Delaware (4)	477.8	406.1	71.7	18%	443.9	381.8	62.1	16%
Total Permian	1,738.5	1,384.5	354.0		1,585.1	1,275.3	309.8	
SouthTX	365.4	365.6	(0.2)	—	389.6	273.2	116.4	43%
North Texas	247.4	251.5	(4.1)	(2%)	244.1	268.1	(24.0)	(9%)
SouthOK	574.1	540.1	34.0	6%	555.7	494.0	61.7	12%
WestOK	354.0	363.5	(9.5)	(3%)	351.6	377.7	(26.1)	(7%)
Total Central	1,540.9	1,520.7	20.2		1,541.0	1,413.0	128.0	
Badlands (5)	90.4	66.5	23.9	36%	85.1	56.5	28.6	51%
Total Field	3,369.8	2,971.7	398.1		3,211.2	2,744.8	466.4	
Coastal	731.1	665.7	65.4	10%	726.2	728.8	(2.6)	—
Total	4,100.9	3,637.4	463.5	13%	3,937.4	3,473.6	463.8	13%
NGL production, MBbl/d (3)								
Permian Midland (4)	169.2	137.5	31.7	23%	153.4	118.3	35.1	30%
Permian Delaware (4)	58.9	45.2	13.7	30%	53.5	43.1	10.4	24%
Total Permian	228.1	182.7	45.4		206.9	161.4	45.5	
SouthTX	47.0	45.7	1.3	3%	51.1	30.4	20.7	68%
North Texas	28.2	28.6	(0.4)	(1%)	28.1	30.2	(2.1)	(7%)
SouthOK	57.6	48.9	8.7	18%	54.7	42.8	11.9	28%
WestOK	22.4	20.5	1.9	9%	20.5	21.9	(1.4)	(6%)
Total Central	155.2	143.7	11.5		154.4	125.3	29.1	
Badlands	11.8	9.4	2.4	26%	10.8	7.9	2.9	37%
Total Field	395.1	335.8	59.3		372.1	294.6	77.5	
Coastal	45.9	39.8	6.1	15%	43.6	38.6	5.0	13%
Total	441.0	375.6	65.4	17%	415.7	333.2	82.5	25%
Crude oil gathered, Badlands, MBbl/d	167.3	119.8	47.5	40%	146.8	113.6	33.2	29%
Crude oil gathered, Permian, MBbl/d (4)	68.2	45.1	23.1	51%	64.9	29.8	35.1	118%
Natural gas sales, BBtu/d (3)	2,006.4	1,717.7	288.7	17%	1,867.9	1,665.4	202.5	12%
NGL sales, MBbl/d	336.4	297.4	39.0	13%	317.6	254.8	62.8	25%
Condensate sales, MBbl/d	12.1	12.8	(0.7)	(5%)	12.6	11.8	0.8	7%
Average realized prices (6):								
Natural gas, $/MMBtu	1.83	2.45	(0.64)	(26%)	1.98	2.65	(0.67)	(25%)
NGL, $/gal	0.54	0.64	(0.10)	(16%)	0.63	0.55	0.08	15%
Condensate, $/Bbl	48.17	51.12	(2.95)	(6%)	55.99	45.52	10.47	23%

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

(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 period.

(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 December 31, 2018 Compared to Three Months Ended December 31, 2017

The increase in gross margin was primarily due to higher Badlands and Permian volumes, partially offset by the impact of lower NGL, natural gas and condensate prices. NGL production, natural gas sales and NGL sales increased due to higher Field Gathering and Processing inlet volumes and increased NGL recoveries including reduced ethane rejection. Coastal Gathering and Processing had a positive margin impact due to higher inlet volumes, richer gas and increased recoveries. Total crude oil gathered volumes increased in the Permian region due to production from new wells. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased due to production from new wells.

Operating expenses increased as a result of higher compensation, contract labor and other costs associated with new plants in the Permian region, partially offset by revisions of ad valorem tax accruals and other costs.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The increase in gross margin was primarily due to higher Permian, Badlands and Central volumes and higher NGL and condensate prices, partially offset by the impact of lower natural gas prices. NGL production, NGL sales and natural gas sales increased due to higher Field Gathering and Processing inlet volumes and increased NGL recoveries including reduced ethane rejection. Coastal Gathering and Processing had a positive margin impact due to richer gas, increased recoveries and higher NGL prices, partially offset by slightly lower inlet volumes. Total crude oil gathered volumes increased in the Permian region due to production from new wells, system expansions and the inclusion of the March 2017 Permian Acquisition for the full year in 2018. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to production from new wells and system expansions.

Operating expenses increased as a result of higher compensation, contract labor and other costs primarily associated with new plants in the Permian and Central regions and system expansions in the Badlands.

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 December 31, 2018			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1), (2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
Permian Midland	1,608.4	Varies (4)	1,260.7	1,260.7
Permian Delaware	477.8	100%	477.8	477.8
Total Permian	2,086.2		1,738.5	1,738.5
SouthTX	365.4	Varies (5)	273.2	365.4
North Texas	247.4	100%	247.4	247.4
SouthOK	574.1	Varies (6)	407.4	574.1
WestOK	354.0	100%	354.0	354.0
Total Central	1,540.9		1,282.0	1,540.9
Badlands (7)	90.4	100%	90.4	90.4
Total Field	3,717.5		3,110.9	3,369.8
NGL production, MBbl/d (2)				
Permian Midland	216.0	Varies (4)	169.2	169.2
Permian Delaware	58.9	100%	58.9	58.9
Total Permian	274.9		228.1	228.1
SouthTX	47.0	Varies (5)	33.6	47.0
North Texas	28.2	100%	28.2	28.2
SouthOK	57.6	Varies (6)	41.1	57.6
WestOK	22.4	100%	22.4	22.4
Total Central	155.2		125.3	155.2
Badlands	11.8	100%	11.8	11.8
Total Field	441.9		365.2	395.1

(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 which are owned 100% by the Company. 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 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.
(7) Badlands natural gas inlet represents the total wellhead gathered volume.

Operating statistics:	Year Ended December 31, 2018			
Plant natural gas inlet, MMcf/d (1), (2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
Permian Midland	1,438.5	Varies (4)	1,141.2	1,141.2
Permian Delaware	443.9	100%	443.9	443.9
Total Permian	1,882.4		1,585.1	1,585.1
SouthTX	389.6	Varies (5)	283.9	389.6
North Texas	244.1	100%	244.1	244.1
SouthOK	555.7	Varies (6)	432.8	555.7
WestOK	351.6	100%	351.6	351.6
Total Central	1,541.0		1,312.4	1,541.0
Badlands (7)	85.1	100%	85.1	85.1
Total Field	3,508.5		2,982.6	3,211.2
NGL production, MBbl/d (2)				
Permian Midland	194.1	Varies (4)	153.4	153.4
Permian Delaware	53.5	100%	53.5	53.5
Total Permian	247.6		206.9	206.9
SouthTX	51.1	Varies (5)	35.9	51.1
North Texas	28.1	100%	28.1	28.1
SouthOK	54.7	Varies (6)	42.8	54.7
WestOK	20.5	100%	20.5	20.5
Total Central	154.4		127.3	154.4
Badlands	10.8	100%	10.8	10.8
Total Field	412.8		345.0	372.1

(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 year and the denominator is the number of calendar days during the year.
(4) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants which are owned 100% by the Company. 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, 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 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.
(7) 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 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 December 31,								Year Ended December 31,							
	2018		2017		2018 vs. 2017				2018		2017		2018 vs. 2017			
							(In millions)									
Gross margin	$	223.7	$	220.0	$	3.7	2%		$	876.8	$	773.4	$	103.4	13%	
Operating expenses		73.0		66.5		6.5	10%			284.3		261.6		22.7	9%	
Operating margin	$	150.7	$	153.5	$	(2.8)	(2%)		$	592.5	$	511.8	$	80.7	16%	
Operating statistics MBbl/d (1):																
Fractionation volumes (2)(3)		449.6		442.6		7.0	2%			426.7		354.2		72.5	20%	
LSNG treating volumes (2)		28.2		33.8		(5.6)	(17%)			32.1		32.2		(0.1)	—	
Benzene treating volumes (2)(4)		—		24.6		(24.6)	(100%)			3.3		21.6		(18.3)	(85%)	
Export volumes (5)		213.2		209.6		3.6	2%			203.4		184.1		19.3	10%	
NGL sales		570.8		554.9		15.9	3%			537.9		490.0		47.9	10%	
Average realized prices:																
NGL realized price, $/gal	$	0.70	$	0.80	$	(0.10)	(13%)		$	0.77	$	0.69	$	0.08	12%	

(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) The benzene saturation unit of the LSNG Hydrotreater was idled in 2018.
(5) 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 December 31, 2018 Compared to Three Months Ended December 31, 2017

Logistics and Marketing gross margin increased due to higher fractionation margin, higher LPG export margin and higher domestic marketing margin, partially offset by lower marketing gains, lower commercial transportation margin, and lower terminaling and storage throughput. 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. Both fractionation supply and LPG export volumes increased in the fourth quarter of 2018 compared to the same period last year despite fourth quarter of 2017 including 29.3 MBbl/d of fractionation supply volume and 12.5 MBbl/d of LPG export volumes deferred from the third quarter of 2017 due to temporary operational issues related to Hurricane Harvey. Domestic marketing margin increased due to higher terminal volumes and higher unit margin. Marketing gains decreased due to reduced optimization of liquids arrangements, partially offset by increased optimization of gas transportation arrangements. Commercial transportation margin decreased primarily due to the sale of the Company's inland marine barge business in the second quarter of 2018. Terminaling and storage throughput decreased due to the sale of certain Petroleum Logistic terminals in the fourth quarter of 2018.

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

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Logistics and Marketing gross margin increased due to higher fractionation margin, higher domestic marketing margin, higher LPG export margin, and higher terminaling and storage throughput, partially offset by lower commercial transportation margin and lower marketing gains. 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 which are largely reflected in operating expenses (see footnote (2) above). Domestic marketing margin increased due to higher terminal volumes and higher unit margins. LPG export margin increased primarily due to higher volumes. Commercial transportation margin decreased primarily due to the sale of the Company's inland marine barge business in the second quarter of 2018.

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

Other

	Three Months Ended December 31, 2018	Three Months Ended December 31, 2017	2018 vs. 2017	Year Ended December 31, 2018	Year Ended December 31, 2017	2018 vs. 2017
			(In millions)			
Gross margin	$ 5.1	$ (13.5)	$ 18.6	$ (37.1)	$ (9.6)	$ (27.5)
Operating margin	$ 5.1	$ (13.5)	$ 18.6	$ (37.1)	$ (9.6)	$ (27.5)

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 gains/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. Additionally, we hedge the commodity price associated with a portion of the Company's future commodity purchases and sales and natural gas transportation basis risk within the Company's Logistics and Marketing segment.

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

	Three Months Ended December 31, 2018			Three Months Ended December 31, 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)	14.9	$ 1.08	$ 16.1	17.8	$ 0.39	$ 6.9
NGL (MMgal)	81.1	(0.11)	(8.7)	85.4	(0.21)	(18.3)
Crude oil (MBbl)	0.5	(5.27)	(2.7)	0.4	(1.31)	(0.5)
Non-hedge accounting (2)			0.4			(1.3)
Ineffectiveness (3)			—			(0.3)
			$ 5.1			$ (13.5)

	Year Ended December 31, 2018			Year Ended December 31, 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)	63.5	$ 0.82	$ 51.9	61.1	$ 0.22	$ 13.5
NGL (MMgal)	367.4	(0.16)	(58.4)	262.9	(0.10)	(26.0)
Crude oil (MBbl)	2.0	(11.26)	(22.7)	1.3	4.09	5.3
Non-hedge accounting (2)			(7.9)			(2.2)
Ineffectiveness (3)			—			(0.2)
			$ (37.1)			$ (9.6)

(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 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 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 $7.6 million and $26.6 million for the years ended December 31, 2017 and 2016, related to these novated contracts. 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, transporting 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 December 31,		Year Ended December 31,	
	2018	**2017**	**2018**	**2017**
		(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ (106.4)	$ 283.1	$ 1.6	$ 54.0
Income attributable to TRP preferred limited partners	2.9	2.9	11.3	11.3
Interest expense, net (1)	61.6	52.4	185.8	233.7
Income tax expense (benefit)	(32.3)	(264.8)	5.5	(397.1)
Depreciation and amortization expense	208.7	206.7	815.9	809.5
Impairment of property, plant and equipment	—	—	—	378.0
Impairment of goodwill	210.0	—	210.0	—
(Gain) loss on sale or disposition of business and assets	(14.4)	(0.7)	(0.1)	15.9
(Gain) loss from financing activities (2)	—	0.3	2.0	16.8
Equity (earnings) loss	(0.9)	0.3	(7.3)	17.0
Distributions from unconsolidated affiliates and preferred partner interests, net	10.1	3.0	31.5	18.0
Change in contingent considerations	(20.9)	26.0	(8.8)	(99.6)
Compensation on equity grants	15.6	10.6	56.3	42.3
Transaction costs related to business acquisitions	—	—	—	5.6
Splitter Agreement (3)	43.0	10.8	75.2	43.0
Risk management activities (4)	0.2	2.8	8.5	10.0
Noncontrolling interests adjustments (5)	(1.4)	(5.0)	(21.1)	(18.6)
TRC Adjusted EBITDA	**$ 375.8**	**$ 328.4**	**$ 1,366.3**	**$ 1,139.8**
Distributions to TRP preferred limited partners	(2.9)	(2.9)	(11.3)	(11.3)
Cash received from payments under Splitter Agreement (3)	—	43.0	43.0	43.0
Splitter Agreement (3)	(43.0)	(10.8)	(75.2)	(43.0)
Interest expense on debt obligations (6)	(66.8)	(55.9)	(252.5)	(224.3)
Cash tax benefit (7)	—	—	—	46.7
Maintenance capital expenditures	(54.6)	(27.7)	(135.0)	(100.7)
Noncontrolling interests adjustments of maintenance capital expenditures	5.5	0.5	7.1	1.6
Distributable Cash Flow	**$ 214.0**	**$ 274.6**	**$ 942.4**	**$ 851.8**

(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 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. In Adjusted EBITDA for 2017, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the Splitter Agreement over the four quarters following receipt. As a result of Vitol's election to terminate the Splitter Agreement in December 2018, the full amount of the 2018 annual cash payment was recognized in Adjusted EBITDA in the fourth quarter of 2018.
(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 of 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 the Company's 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 (loss) attributable to TRC. 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 December 31, 2018	Three Months Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ (106.4)	$ 283.1	$ 1.6	$ 54.0
Net income (loss) attributable to noncontrolling interests	18.4	16.1	58.8	50.2
Net income (loss)	(88.0)	299.2	60.4	104.2
Depreciation and amortization expense	208.7	206.7	815.9	809.5
General and administrative expense	80.0	54.0	256.9	203.4
Impairment of property, plant and equipment	—	—	—	378.0
Impairment of goodwill	210.0	—	210.0	—
Interest expense, net	61.6	52.4	185.8	233.7
Income tax expense (benefit)	(32.3)	(264.8)	5.5	(397.1)
(Gain) loss on sale or disposition of assets	(14.4)	(0.7)	(0.1)	15.9
(Gain) loss from financing activities	—	0.3	2.0	16.8
Other, net	(19.7)	27.3	(12.6)	(78.5)
Operating margin	405.9	374.4	1,523.8	1,285.9
Operating expenses	183.3	160.2	722.0	622.9
Gross margin	**$ 589.2**	**$ 534.6**	**$ 2,245.8**	**$ 1,908.8**

The following table presents a reconciliation of estimated net income of the Company to estimated Adjusted EBITDA for 2019:

	Year Ended December 31, 2019
	(In millions)
Reconciliation of Estimated Net Income attributable to TRC to Adjusted EBITDA	
Net income attributable to TRC	$ 44.0
Income attributable to TRP preferred limited partners	11.3
Interest expense, net	330.0
Income tax expense (benefit)	—
Depreciation and amortization expense	925.0
(Earnings) loss from unconsolidated affiliates	(30.0)
Distributions from unconsolidated affiliates and preferred partner interests, net	50.0
Compensation on equity grants	60.0
Noncontrolling interest adjustments	(40.3)
TRC Estimated Adjusted EBITDA	**$ 1,350.0**

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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