November 2, 2016

Targa Resources Corp. Reports Third Quarter 2016 Financial Results

HOUSTON, Nov. 02, 2016 (GLOBE NEWSWIRE) -- Targa Resources Corp. (NYSE:TRGP) ("TRC", the "Company" or "Targa") today reported third quarter 2016 results.

Third Quarter 2016 Financial Results

Third quarter 2016 net income (loss) attributable to Targa Resources Corp. was ($10.7) million compared to $12.7 million for the third quarter of 2015.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $245.3 million for the third quarter of 2016 compared to $311.3 million for the third quarter of 2015 (see the section of this release entitled "Targa Resources Corp. - Non-GAAP Financial Measures" for a discussion of Adjusted EBITDA, distributable cash flow, gross margin and operating margin, and reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP")).

"We continue to see strong results for our businesses in the Permian and are encouraged with operational performance across the company. The third quarter drop in LPG export volumes has been more than offset by recent export activity, and we now expect to exceed our full year guidance for average export volumes," said Joe Bob Perkins, Chief Executive Officer of the Company. "With this performance, coupled with the receipt of the first annual payment related to the crude and condensate splitter, Adjusted EBITDA for the fourth quarter will likely be the highest of the year. We expect fourth quarter dividend coverage approaching 1.2 times and full year coverage consistent with our guidance of slightly above 1.0 times. Looking forward, our Field Gathering and Processing volumes should grow with improving prices, and our Downstream businesses will benefit from similar trends."

On October 19, 2016, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended September 30, 2016, or $3.64 per share on an annualized basis, unchanged to the previous quarter's dividend. Total cash dividends of approximately $164.6 million will be paid November 15, 2016 on all outstanding shares of common stock to holders of record as of the close of business on November 2, 2016. Also on October 19, 2016, TRC declared a quarterly cash dividend of $23.75 per share of Series A Preferred Stock. Total cash dividends of approximately $22.9 million will be paid on November 14, 2016 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on November 2, 2016.

The Company reported distributable cash flow for the third quarter of 2016 of $168.3 million compared to total common dividends of $164.6 million and total Series A Preferred Stock dividends of $22.9 million.

Third Quarter 2016 - Capitalization, Liquidity and Financing

Targa's total consolidated debt as of September 30, 2016 was $4,950.9 million including $275 million outstanding under TRC's $670 million senior secured revolving credit facility due 2020 and $157.7 million, net of unamortized discounts, outstanding on the Company's senior secured term loan due 2022. The consolidated debt also included $4,522.1 million of Targa Resource Partners LP ("TRP" or "the Partnership") debt, net of $29.4 million of debt issuance costs, comprised of $225 million outstanding under TRP's accounts receivable securitization facility and $4,326.5 million of TRP senior notes, net of unamortized discounts and premiums.

As of September 30, 2016, TRC had available senior secured revolving credit facility capacity of $395.0 million. TRP had no borrowings outstanding under its $1.6 billion senior secured revolving credit facility and $13.5 million in outstanding letters of credit, resulting in available senior secured revolving credit facility capacity of $1,586.5 million at the Partnership. Total Targa consolidated liquidity as of September 30, 2016, including $141.1 million of cash, was approximately $2.1 billion.

In October 2016, the Partnership issued $500.0 million of 5⅛% Senior Notes due February 2025 and $500.0 million of 5⅜% Senior Notes due February 2027 yielding total net proceeds of approximately $992 million. The net proceeds from the offering along with borrowings under its senior secured revolving credit facility were used to fund concurrent tender offers for other series of senior notes, as described below.

Concurrently with the October 2016 offering, the Partnership commenced tender offers (the "Tender Offers") to purchase for cash, subject to certain conditions, its 5% Senior Notes due January 2018 (the "5% Notes"), 6⅝% Senior Notes due October 2020 (the "6⅝% Notes") and 6⅞% Senior Notes due February 2021 (the "6⅞% Notes" and together with the 5% Notes and 6⅝% Notes, the "Tender Notes"). The total consideration for each series of Tender Notes included a premium for each $1,000 principal amount of notes that was tendered as of the early tender date of October 5, 2016. The Tender Offers were fully subscribed and the Partnership accepted for purchase all Tender Notes that were validly tendered as of the early tender date.

The results of the Tender Offers, which closed in October 2016, were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer Payments	Note Balance After Tender Offers
5% Senior Notes	$ 733.6	$ 483.1	$ 16.9	$ 5.4	$ 505.4	$ 250.5
6⅝% Senior Notes	309.9	281.7	10.5	0.3	292.5	28.2
6⅞% Senior Notes	478.6	373.5	14.4	4.6	392.5	105.1
	$ 1,522.1	$ 1,138.3	$ 41.8	$ 10.3	$ 1,190.4	$ 383.8

Subsequent to the closing of the Tender Offers, the Partnership issued notices of full redemption to the trustees and noteholders of the 6⅝% Notes and the 6⅞% Notes for the note balances remaining after the Tender Offers. In addition, the Partnership issued notice of full redemption to the trustees and noteholders of the 6⅝% APL Notes due October 2020. The redemption price for the 6⅝% Notes and the 6⅝% APL Notes due October 2020 was 103.313% of the principal amount, while the redemption price for the 6⅞% Notes was 103.438% of the principal amount. The aggregate principal amount outstanding of all three series of notes totaling $146.2 million will be redeemed on November 15, 2016 for a total redemption payment of $151.1 million, excluding accrued interest.

In October 2016, the Partnership amended and restated its senior secured revolving credit facility to extend the maturity date from October 2017 to October 2020. The available commitments under the facility of $1.6 billion remained unchanged while the Partnership's ability to request additional commitments increased from up to $300.0 million to up to $500.0 million.

Conference Call

Targa will host a conference call for investors and analysts at 10:00 a.m. Eastern time (9:00 a.m. Central time) on November 2, 2016 to discuss third quarter 2016 financial results. The conference call can be accessed via webcast through the Events and Presentations section of Targa's website at www.targaresources.com, by going directly to http://ir.targaresources.com/events.cfm or by dialing 877-881-2598. The conference ID number for the dial-in is 3874175. Please dial in ten minutes prior to the scheduled start time. A replay will be available approximately two hours following the completion of the webcast through the Investors section of the Company's website. An updated investor presentation will also be available in the Events and Presentations section of the Company's websites following the completion of the conference call.

Targa Resources Corp. — Consolidated Financial Results of Operations

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	($ in millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 1,398.7	$ 1,321.3	$ 77.4	6 %	$ 3,882.9	$ 4,119.6	$ (236.7)	(6 %)
Fees from midstream services	253.6	310.8	(57.2)	(18 %)	795.5	891.6	(96.1)	(11 %)
Total revenues	1,652.3	1,632.1	20.2	1 %	4,678.4	5,011.2	(332.8)	(7 %)

Product purchases	1,222.7	1,163.3	59.4	5%	3,378.9	3,650.0	(271.1)	(7%)
Gross margin (1)	429.6	468.8	(39.2)	(8%)	1,299.5	1,361.2	(61.7)	(5%)
Operating expenses	143.0	142.7	0.3	0%	414.0	409.6	4.4	1%
Operating margin (1)	286.6	326.1	(39.5)	(12%)	885.5	951.6	(66.1)	(7%)
Depreciation and amortization expenses	184.0	165.8	18.2	11%	563.6	448.3	115.3	26%
General and administrative expenses	46.1	44.9	1.2	3%	138.3	136.5	1.8	1%
Goodwill impairment	—	—	—	—	24.0	—	24.0	—
Other operating expenses	4.9	0.1	4.8	NM	6.1	0.6	5.5	NM
Income from operations	51.6	115.3	(63.7)	(55%)	153.5	366.2	(212.7)	(58%)
Interest expense, net	(62.7)	(67.8)	5.1	8%	(187.0)	(189.5)	2.5	1%
Equity earnings (loss)	(2.2)	(1.6)	(0.6)	38%	(11.4)	(1.1)	(10.3)	NM
Gain (loss) from financing activities	—	(0.5)	0.5	100%	21.4	(13.4)	34.8	260%
Other income (expense)	1.4	(0.6)	2.0	NM	1.2	(27.5)	28.7	104%
Income tax (expense) benefit	8.7	(24.0)	32.7	136%	3.9	(54.1)	58.0	107%
Net income (loss)	(3.2)	20.8	(24.0)	(115%)	(18.4)	80.6	(99.0)	(123%)
Less: Net income (loss) attributable to noncontrolling interests	7.5	8.1	(0.6)	(7%)	18.2	49.2	(31.0)	(63%)
Net income (loss) attributable to Targa Resources Corp.	(10.7)	12.7	(23.4)	(184%)	(36.6)	31.4	(68.0)	(217%)
Dividends on Series A preferred stock	22.9	—	22.9	—	49.7	—	49.7	—
Deemed dividends on Series A preferred stock	5.8	—	5.8	—	12.3	—	12.3	—
Net income (loss) attributable to common shareholders	$ (39.4)	$ 12.7	$ (52.1)	NM	$ (98.6)	$ 31.4	$ (130.0)	NM
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	$ 245.3	$ 311.3	$ (66.0)	(21%)	$ 767.1	$ 865.7	$ (98.6)	(11%)
Distributable cash flow (1)	168.3	220.6	(52.3)	(24%)	516.0	614.2	(98.2)	(16%)
Capital expenditures	134.6	186.2	(51.6)	(28%)	426.5	571.0	(144.5)	(25%)
Business acquisitions	—	—	—	—	—	5,024.2	(5,024.2)	(100%)
Operating statistics:								
Crude oil gathered, MBbl/d	103.9	108.9	(5.0)	(5%)	105.7	105.4	0.3	0%
Plant natural gas inlet, MMcf/d (2) (3) (4)	3,370.1	3,452.5	(82.3)	(2%)	3,432.9	3,163.5	269.4	9%
Gross NGL production, MBbl/d (4)	310.4	284.5	25.9	9%	305.4	256.8	48.6	19%
Export volumes, MBbl/d (5)	156.7	184.1	(27.4)	(15%)	173.0	180.0	(7.1)	(4%)
Natural gas sales, BBtu/d (3) (4) (6)	1,993.0	1,932.4	60.6	3%	1,975.4	1,721.4	253.9	15%
NGL sales, MBbl/d (4) (6)	497.3	500.1	(2.8)	(1%)	520.6	501.5	19.1	4%
Condensate sales, MBbl/d (4)	10.0	10.8	(0.8)	(7%)	10.3	9.5	0.8	8%

(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) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.
(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.
(6) Includes the impact of intersegment eliminations.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

The increase in revenues was primarily due to higher NGL prices ($104.0 million) and higher natural gas sales volumes ($14.3 million), partially offset by decreased fee-based and other revenues ($57.1 million) from lower fractionation and export fees, and lower crude and natural gas prices ($11.3 million).

Higher NGL prices brought a commensurate increase in product purchases.

The lower operating margin and gross margin in 2016 was primarily attributable to decreased segment results for Logistics and Marketing. Improved margins in the Company's Gathering and Processing segment were essentially offset by lower commodity derivative settlement revenues in Other. Operating expenses were relatively flat in 2016 as compared with 2015. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expenses primarily reflects the impact of growth investments from system expansions.

General and administrative expenses were relatively flat in 2016 as compared with 2015.

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

The decrease in net interest expense in 2016 is primarily due to $4.2 million of non-cash interest income resulting from the change in estimated redemption value of the mandatorily redeemable preferred interests for the three months ended September 30, 2016.

The decrease in net income attributable to noncontrolling interests was primarily attributable to the acquisition of TRP common units as part of the TRC/TRP Merger in February 2016 and lower earnings in 2016 at the Company's joint ventures, partially offset by $2.8 million of distributions for the three months ended September 30, 2016 for the Partnership's Preferred Units issued in October 2015.

Preferred dividends in 2016 represent both cash dividends paid on Series A Preferred Stock and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. The Series A Preferred Stock was issued on March 16, 2016.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

The decrease in revenues was primarily due to lower commodity prices ($521.6 million), partially offset by the favorable impact of inclusion of two additional months of operations of Targa Pipeline Partners LP ("TPL") during 2016 ($270.1 million). Additionally, fee-based and other revenues decreased due to lower fractionation and export fees ($97.9 million), partially offset by the impact of an additional two months of TPL's fee revenue in 2016 ($40.9 million).

Lower commodity prices brought a commensurate reduction in product purchases, partially offset by the inclusion of two additional months of operations from TPL in 2016 ($137.5 million).

The lower operating and gross margin in 2016 reflects decreased segment margin results for Logistics and Marketing, partially offset by increased Gathering and Processing margins. Operating expenses were relatively flat compared with 2015 due to the inclusion of TPL's operations for an additional two months in 2016, offset by a continued focused cost reduction effort throughout the Company's operating areas. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expenses is primarily due to an additional two months of TPL operations in 2016, growth investments from other system expansions including CBF Train 5, the Buffalo Plant, compressor stations and pipelines, and higher amortization of the Badlands intangible assets.

General and administrative expenses, which include TPL operations for an additional two months in 2016, reflect operational synergies, including integrating TPL into Targa's insurance program.

During 2016, the Company recognized an additional impairment of goodwill of $24.0 million to finalize the $290.0 million provisional impairment recorded during the fourth quarter of 2015.

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

The decrease in net interest expense primarily reflects $18.8 million of non-cash interest income resulting from the change in estimated redemption value of the mandatorily redeemable preferred interest during 2016 and lower interest expense resulting from $534.3 million of open market debt repurchases during 2016, partially offset by higher interest expense resulting from the Partnership's September 2015 issuance of $600.0 million of 6¾% Senior Notes.

The decrease in equity earnings (loss) is due to lower operating results from GCF and the inclusion of an additional two months of equity losses from the T2 Joint Ventures in 2016.

Other expense in 2015 was primarily attributable to non-recurring transaction costs related to the Company and TRP's mergers with TPL and Targa Energy LP, respectively (collectively, the "Atlas mergers").

During the nine months ended September 30, 2016, the Company repurchased $534.3 million of debt in open market purchases, which generated a net gain from financing activities of $21.4 million, while in 2015 the Company incurred a net loss from financing activities of $13.4 million from the partial repayments of the TRC senior secured term loan.

The decrease in net income attributable to noncontrolling interests was primarily attributable to the TRC/TRP Merger in February 2016 and lower earnings in 2016 at the Company's joint ventures, partially offset by $8.4 million of distributions for the nine months ended September 30, 2016 for the TRP's Preferred Units issued in October 2015.

Preferred dividends in 2016 represent both cash dividends paid on Series A Preferred Stock and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. The Series A Preferred Stock was issued on March 16, 2016.

Review of Segment Performance

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

The Company operates in two primary segments (previously referred to as divisions): (i) Gathering and Processing, previously disaggregated into two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing (also referred to as the Downstream Business), previously disaggregated into two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution.

Concurrent with the TRC/TRP Merger, management reevaluated the Company's reportable segments and determined that its divisions are the appropriate level of disclosure for the Company's reportable segments. The increase in activity within Field Gathering and Processing due to the Atlas mergers coupled with the decline in activity in the Gulf Coast region makes the disaggregation of Field Gathering and Processing and Coastal Gathering and Processing no longer warranted. Management also determined that further disaggregation of the Logistics and Marketing division is no longer appropriate due to the integrated nature of the operations within TRC's Downstream Business and its leadership by a consolidated executive management team.

Gathering and Processing Segment

The Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
Gross margin	$ 231.7	$ 224.0	$ 7.7	3%	$ 648.0	$ 609.0	$ 39.0	6%
Operating expenses	82.3	83.5	(1.2)	(1%)	243.9	237.0	6.9	3%
Operating margin	$ 149.4	$ 140.5	$ 8.9	6%	$ 404.1	$ 372.0	$ 32.1	9%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	262.5	240.2	22.3	9%	255.1	231.6	23.5	10%
WestTX (5)	519.4	460.2	59.2	13%	491.3	344.3	147.0	43%
Sand Hills (4)	140.9	168.1	(27.2)	(16%)	142.6	166.1	(23.5)	(14%)
Versado	180.6	187.8	(7.2)	(4%)	176.5	182.3	(5.8)	(3%)
Total Permian	1,103.4	1,056.3	47.1		1,065.5	924.3	141.2	
SouthTX (5)	218.0	139.1	78.9	57%	219.7	113.2	106.5	94%
North Texas	315.2	339.1	(23.9)	(7%)	323.4	351.7	(28.3)	(8%)
SouthOK (5)	469.8	473.8	(4.0)	(1%)	466.1	378.2	87.9	23%
WestOK (5)	434.4	563.4	(129.0)	(23%)	455.6	458.6	(3.0)	(1%)
Total Central	1,437.4	1,515.4	(78.0)		1,464.8	1,301.7	163.1	
Badlands (6)	53.8	50.7	3.1	6%	52.9	46.6	6.3	14%
Total Field	2,594.6	2,622.4	(27.8)		2,583.2	2,272.6	310.6	
Coastal	775.5	830.1	(54.6)	(7%)	849.7	891.0	(41.3)	(5%)
Total	3,370.1	3,452.5	(82.4)	(2%)	3,432.9	3,163.6	269.3	9%
Gross NGL production, MBbl/d (3)								
SAOU (4)	32.8	28.6	4.2	15%	31.4	27.2	4.2	15%
WestTX (5)	67.6	53.6	14.0	26%	60.7	40.1	20.6	51%
Sand Hills (4)	15.2	17.5	(2.3)	(13%)	15.0	17.6	(2.6)	(15%)
Versado	21.8	24.0	(2.2)	(9%)	21.3	23.5	(2.2)	(9%)
Total Permian	137.4	123.7	13.7		128.4	108.4	20.0	
SouthTX (5)	20.9	13.7	7.2	53%	25.1	13.2	11.9	90%
North Texas	36.2	39.0	(2.8)	(7%)	36.3	40.2	(3.9)	(10%)
SouthOK (5)	42.4	30.3	12.1	40%	39.3	23.4	15.9	68%
WestOK (5)	27.2	27.9	(0.7)	(3%)	27.9	22.9	5.0	22%
Total Central	126.7	110.9	15.8		128.6	99.7	28.9	
Badlands	7.8	7.4	0.4	5%	7.5	6.3	1.2	19%
Total Field	271.9	242.0	29.9		264.5	214.4	50.1	

Coastal	38.6	41.4	(2.8)	(7%)	41.0	41.0	-	-
Total	310.5	283.4	27.1	10%	305.5	255.4	50.1	20%
Crude oil gathered, MBbl/d	103.9	108.9	(5.0)	(5%)	105.7	105.4	0.3	0%
Natural gas sales, BBtu/d (3)	1,617.6	1,746.2	(128.6)	(7%)	1,636.8	1,540.1	96.7	6%
NGL sales, MBbl/d	248.4	223.4	25.0	11%	241.3	198.5	42.8	22%
Condensate sales, MBbl/d	9.7	10.6	(0.9)	(8%)	10.0	9.3	0.7	8%
Average realized prices (7):								
Natural gas, $/MMBtu	2.49	2.52	(0.03)	(1%)	1.96	2.49	(0.53)	(21%)
NGL, $/gal	0.36	0.32	0.04	13%	0.33	0.36	(0.03)	(8%)
Condensate, $/Bbl	38.29	40.68	(2.39)	(6%)	34.18	44.02	(9.84)	(22%)

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter, including the volumes related to plants acquired in the APL merger.
(2) Plant natural gas inlet represents 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.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes wellhead gathered volumes moved from Sand Hills via pipeline to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Badlands natural gas inlet represents the total wellhead gathered volume.
(7) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

The increase in gross margin was primarily due to higher NGL prices offset by lower inlet volumes and lower condensate prices. Plant inlet volumes increased in the Permian region driven by WestTX and SAOU. The volume increase at SouthTX partially offset an overall inlet volume decrease in the Central region. Despite overall lower inlet volumes, NGL production increased primarily due to additional ethane recovery at SouthOK. Natural gas sales volumes decreased due to lower inlet volumes. Badlands natural gas volumes increased due to system expansions for specific gas and oil producers while crude oil volumes decreased due to reduced producer activity by crude oil only producers.

Operating expenses decreased primarily due to a continued focus on cost reductions, which more than offset increased expenses associated with the commencement of commercial operations in April 2016 at the Buffalo plant in WestTX, other system expansions and an operational issue at Versado.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

The increase in gross margin was primarily due to the inclusion of the TPL volumes for three quarters of 2016 partially offset by lower commodity prices and lower inlet volumes on the Company's other systems. The plant inlet volume increases in the Permian region attributable to SAOU were offset by reduced producer activity and operational issues at Sand Hills and Versado and in the Central region by reduced producer activity and volumes in North Texas. Badlands crude oil and natural gas volumes increased due to plant and system expansions. Coastal plant inlet volumes decreased due to current market conditions and the decline of off-system volumes partially offset by additional higher GPM volumes.

Excluding the impact of including operating expenses for TPL for an additional two months in 2016 and system expansions, operating expenses for most areas were significantly lower due to a continued focused cost reduction effort.

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, 2016

Operating statistics:

Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	262.5	100 %	262.5	262.5
WestTX (5)(6)(7)	713.4	73 %	519.4	519.4
Sand Hills (4)	140.9	100 %	140.9	140.9
Versado (8)	180.6	63 %	113.8	180.6
Total Permian	1,297.4		1,036.6	1,103.4
SouthTX (5)	218.0	Varies (9)	205.6	218.0
North Texas	315.2	100 %	315.2	315.2
SouthOK (5)	469.8	Varies (10)	392.8	469.8
WestOK (5)	434.4	100 %	434.4	434.4
Total Central	1,437.4		1,348.0	1,437.4
Badlands (11)	53.8	100 %	53.8	53.8
Total Field	2,788.6		2,438.4	2,594.6
Gross NGL production, MBbl/d (2)				
SAOU (4)	32.8	100 %	32.8	32.8
WestTX (5)(6)(7)	92.9	73 %	67.6	67.6
Sand Hills (4)	15.2	100 %	15.2	15.2
Versado (8)	21.8	63 %	13.7	21.8
Total Permian	162.7		129.3	137.4
SouthTX (5)	20.9	Varies (9)	19.7	20.9
North Texas	36.2	100 %	36.2	36.2
SouthOK (5)	42.4	Varies (10)	39.1	42.4
WestOK (5)	27.2	100 %	27.2	27.2
Total Central	126.7		122.2	126.7
Badlands	7.8	100 %	7.8	7.8
Total Field	297.2		259.3	271.9

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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.
(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 wellhead gathered volumes moved from Sand Hills to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.
(7) Includes the Buffalo Plant that commenced commercial operations in April 2016.
(8) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(9) SouthTX includes the Silver Oak II plant, of which TPL has owned a 90% interest since January 2016, and prior to which TPL owned a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(10) SouthOK includes the Centrahoma joint venture, of which TPL owns 60% and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(11) Badlands natural gas inlet represents the total wellhead gathered volume.

	Three Months Ended September 30, 2015			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	240.2	100 %	240.2	240.2
WestTX (5)(6)	632.1	73 %	460.2	460.2

Sand Hills (4)	168.1	100 %	168.1	168.1
Versado (7)	187.8	63 %	118.3	187.8
Total Permian	1,228.2		986.8	1,056.3
SouthTX (5)	139.1	100 %	139.1	139.1
North Texas	339.1	100 %	339.1	339.1
SouthOK (5)	473.8	Varies (8)	397.1	473.8
WestOK (5)	563.4	100 %	563.4	563.4
Total Central	1,515.4		1,438.7	1,515.4
Badlands (9)	50.7	100 %	50.7	50.7
Total Field	2,794.3		2,476.2	2,622.4
Gross NGL production, MBbl/d (2)				
SAOU (4)	28.6	100 %	28.6	28.6
WestTX (5)(6)	73.6	73 %	53.6	53.6
Sand Hills (4)	17.5	100 %	17.5	17.5
Versado (7)	24.0	63 %	15.1	24.0
Total Permian	143.7		114.8	123.7
SouthTX (5)	13.7	100 %	13.7	13.7
North Texas	39.0	100 %	39.0	39.0
SouthOK (5)	30.3	Varies (8)	27.0	30.3
WestOK (5)	27.9	100 %	27.9	27.9
Total Central	110.9		107.6	110.9
Badlands	7.4	100 %	7.4	7.4
Total Field	262.0		229.8	242.0

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(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, other than for the volumes related to the APL merger, for which the denominator is 31 days.
(4) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.
(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(8) SouthOK includes the Centrahoma joint venture, of which TPL owns 60% and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(9) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

The Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, distributing and marketing of NGLs, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of Targa's other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of the Company's other operations, as well as transporting natural gas and NGLs.

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

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

	Three Months Ended September 30,		2016 vs. 2015		Nine Months Ended September 30,		2016 vs. 2015	
	2016	2015			2016	2015		
		($ in millions)						
Gross margin	$ 186.7	$ 223.3	$ (36.6)	(16%)	$ 594.6	$ 692.0	$ (97.4)	(14%)
Operating expenses	60.7	59.5	1.2	2%	170.1	173.0	(2.9)	(2%)
Operating margin	$ 126.0	$ 163.8	$ (37.8)	(23%)	$ 424.5	$ 519.0	$ (94.5)	(18%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	313.2	344.6	(31.4)	(9%)	312.8	347.7	(34.9)	(10%)
LSNG treating volumes (2)	25.6	23.8	1.8	8%	23.3	22.8	0.5	2%
Benzene treating volumes (2)	20.2	23.8	(3.6)	(15%)	21.4	22.8	(1.4)	(6%)
Export volumes, MBbl/d (4)	156.7	184.1	(27.4)	(15%)	173.0	180.0	(7.0)	(4%)
NGL sales, MBbl/d	452.4	392.1	60.3	15%	466.3	416.3	50.0	12%
Average realized prices:								
NGL realized price, $/gal	$ 0.46	$ 0.41	$ 0.06	15%	$ 0.45	$ 0.47	$ (0.02)	(4%)

(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 year.
(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.
(4) Export volumes represent the quantity of NGL products delivered to third-party customers at the Company's Galena Park Marine terminal that are destined for international markets.

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

Logistics and Marketing gross margin decreased primarily due to lower LPG export margin, the realization in 2015 of contract renegotiation fees related to the Company's crude and condensate splitter project, and various other items, partially offset by increased fractionation margin. LPG export margin decreased due to lower fees and volumes, partially offset by cancellation fees. Fractionation margin increased primarily due to higher system product gains, partially offset by a decrease in supply volume.

Operating expenses increased due to higher taxes associated with the start-up of CBF Train 5, partially offset by lower maintenance expense resulting primarily from fewer required well workovers and pipeline integrity tests in the third quarter 2016 compared to the same period last year, with continued focused reductions in nonessential maintenance projects also contributing.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Logistics and Marketing gross margin decreased due to lower LPG export margin, the realization in 2015 of contract renegotiation fees related to the Company's crude and condensate splitter project, lower fractionation margin and lower terminaling and storage throughput. LPG export margin decreased due to lower fees and volumes, partially offset by cancellation fees. Fractionation margin decreased due to lower volumes and system product gains, and was partially impacted by the variable effects of fuel and power which are largely reflected in lower operating expenses (see footnote (2) above).

Operating expenses decreased primarily due to lower fuel and power expense, and lower maintenance expense resulting from continued focused cost reductions in nonessential maintenance projects. These decreases were partially offset by higher taxes associated with the start-up of CBF Train 5.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	2016 vs. 2015	2016	2015	2016 vs. 2015
			($ in millions)			
Gross margin	$ 11.2	$ 21.8	$ (10.6)	$ 56.9	$ 60.7	$ (3.8)
Operating margin	$ 11.2	$ 21.8	$ (10.6)	$ 56.9	$ 60.7	$ (3.8)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column. The primary purpose of Targa's commodity risk management activities is to mitigate a portion of the impact of commodity prices on its operating cash flow. The Company has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes and (ii) NGL and condensate equity volumes in its Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because the Company is essentially forward-selling a portion of its 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, 2016			Three Months Ended September 30, 2015			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2016 vs. 2015
Natural gas (BBtu)	13.8	$ 0.37	$ 5.1	11.0	$ 0.70	$ 7.7	$ (2.6)
NGL (MMgal)	15.2	0.12	1.8	9.3	0.93	8.6	(6.8)
Crude oil (MBbl)	0.3	14.40	4.7	0.3	32.89	9.0	(4.3)
Non-hedge accounting (2)			(0.1)			(4.1)	4.0
Ineffectiveness (3)			(0.3)			0.6	(0.9)
			$ 11.2			$ 21.8	$ (10.6)

	Nine Months Ended September 30, 2016			Nine Months Ended September 30, 2015			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2016 vs. 2015
Natural gas (BBtu)	34.0	$ 0.94	$ 31.9	21.1	$ 1.07	$ 22.6	$ 9.3
NGL (MMgal)	74.1	0.09	6.9	24.3	0.74	18.1	(11.2)
Crude oil (MBbl)	0.8	20.02	16.2	0.6	30.52	19.4	(3.2)
Non-hedge accounting (2)			2.5			(0.7)	3.2
Ineffectiveness (3)			(0.6)			1.3	(1.9)
			$ 56.9			$ 60.7	$ (3.8)

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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) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Company and included in the acquisition date fair value of assets acquired. Derivative settlements of $5.8 million and $20.9 million related to these novated contracts were received during the three and nine months ended September 30, 2016 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired with no effect on results of operations.

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. Targa owns, operates, acquires, and develops a diversified portfolio of complementary midstream energy assets. The Company is primarily engaged in the business of: gathering, compressing, treating, processing, and selling natural gas; storing, fractionating, treating, transporting, and selling NGLs and NGL products, including services to LPG exporters; gathering, storing, and terminaling crude oil; storing, terminaling, and selling refined petroleum products.

The principal executive offices of Targa are located at 1000 Louisiana, Suite 4300, Houston, TX 77002 and their telephone number is 713-584-1000. For more information please go to 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) available to TRC before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger; non-cash compensation on equity grants; transaction costs related to business acquisitions; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expenses. 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 Targa Resources Corp. Adjusted EBITDA should not be considered as an alternative to GAAP net income. Adjusted EBITDA has important limitations as an analytical tool. Investors should not consider Adjusted EBITDA in isolation or as a substitute for analysis of the Company's results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in the Company's industry, the Company's definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Distributable Cash Flow

The Company defines distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, cash interest expense on debt obligations, cash tax expenses 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 its 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 its 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 its decision-making processes.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ (10.7)	$ 12.7	$ (36.6)	$ 31.4
Impact of TRC/TRP Merger on NCI	—	3.3	(3.8)	31.9
Income attributable to TRP preferred limited partners	2.8	—	8.4	—
Interest expense, net	62.7	67.8	187.0	189.5
Income tax expense (benefit)	(8.7)	24.0	(3.9)	54.1
Depreciation and amortization expenses	184.0	165.8	563.6	448.3
Goodwill impairment	—	—	24.0	—
(Gain) loss on sale or disposition of assets	4.7	—	5.7	(0.2)
(Gain) loss from financing activities	—	0.5	(21.4)	13.4
(Earnings) loss from unconsolidated affiliates	2.2	1.6	11.4	1.1
Distributions from unconsolidated affiliates and preferred partner interests, net	3.8	11.5	12.6	17.3
Change in contingent consideration	(0.3)	—	(0.3)	—
Compensation on equity grants	7.0	6.6	22.2	19.0
Transaction costs related to business acquisitions	—	0.5	—	27.3
Risk management activities	6.2	21.8	18.7	46.0
Noncontrolling interests adjustments (1)	(8.4)	(4.8)	(20.5)	(13.4)
TRC Adjusted EBITDA	**$ 245.3**	**$ 311.3**	**$ 767.1**	**$ 865.7**
Distributions to TRP preferred limited partners	(2.8)	—	(8.4)	—
Interest expenses on debt obligations (2)	(65.5)	(66.5)	(201.1)	(184.4)
Cash tax (expense) benefit (3)	11.1	—	11.1	—
Maintenance capital expenditures	(21.1)	(26.7)	(56.3)	(73.0)
Noncontrolling interests adjustments of maintenance capex	1.3	2.5	3.6	5.9
Distributable Cash Flow	**$ 168.3**	**$ 220.6**	**$ 516.0**	**$ 614.2**

(1) Noncontrolling interest portion of depreciation and amortization expenses.
(2) Excludes amortization of interest expense.
(3) Includes adjustment for tax attributes related to the TRC/TRP Merger.

Gross Margin

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

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

Logistics and Marketing segment gross margin consists primarily of

- service fee revenues (including the pass-through of energy costs included in fee rates),
- system product gains and losses, and
- NGL and natural gas sales less NGL and natural gas purchases, transportation costs and the net inventory change.

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

Operating Margin

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

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

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

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of the Company's results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in the Company's industry, the Company's definitions of gross margin and operating margin may not be comparable with similarly titled measures of other companies, thereby diminishing their utility.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
		(In millions)		
Reconciliation of TRC Gross Margin and Operating Margin to Net Income (Loss) attributable to TRC:				
Gross margin	$ 429.6	$ 468.8	$ 1,299.5	$ 1,361.2
Operating expenses	(143.0)	(142.7)	(414.0)	(409.6)
Operating margin	286.6	326.1	885.5	951.6
Depreciation and amortization expenses	(184.0)	(165.8)	(563.6)	(448.3)
General and administrative expenses	(46.1)	(44.9)	(138.3)	(136.5)
Goodwill impairment	—	—	(24.0)	—
Interest expense, net	(62.7)	(67.8)	(187.0)	(189.5)
Income tax (expense) benefit	8.7	(24.0)	3.9	(54.1)
Gain (loss) on sale or disposition of assets	(4.7)	—	(5.7)	0.2
Gain (loss) from financing activities	—	(0.5)	21.4	(13.4)

Other, net	(1.0)	(2.3)	(10.6)	(29.4)
Net income (loss)	(3.2)	20.8	(18.4)	80.6
Less: Net income (loss) attributable to noncontrolling interests	7.5	8.1	18.2	49.2
Net income (loss) attributable to TRC	**$ (10.7)**	**$ 12.7**	**$ (36.6)**	**$ 31.4**

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 Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K. The Company does not undertake an obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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Executive Vice President and Chief Financial Officer