SIERRA WIRELESS INC
Form 6-K
March 19, 2019

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

FORM 6-K

Report of Foreign Private Issuer
Pursuant to Rule 13a-16 or 15d-16 of the
Securities Exchange Act of 1934

For the Month of March 2019

(Commission File. No. 000-30718).

SIERRA WIRELESS, INC.
(Translation of registrant's name in English)

13811 Wireless Way
Richmond, British Columbia, Canada V6V 3A4
(Address of principal executive offices and zip code)

Registrant's Telephone Number, including area code: 604-231-1100

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F:

Form 20-F o 40-F ý

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes: o No: ý

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):

Yes: o No: ý

SIGNATURES

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

Sierra Wireless, Inc.

By: /s/ David G. McLennan

David G. McLennan, Chief Financial Officer and Secretary

Date: March 19, 2019

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0.9

Miscellaneous business tax

0.2

0.1

0.3

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$

0.3

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0.1

$

16.5

$

1.1

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(1) Comprised primarily of a $16.1 million loss in the first quarter of 2017 due to the reduction in the carrying value of our ownership interest in VGS in connection with the April 4, 2017 sale.

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Note 20 - Supplemental Cash Flow Information

	Six Months Ended June 30, 2017	2016
Cash:		
Interest paid, net of capitalized interest (1)	$ 109.2	$ 142.2
Income taxes paid, net of refunds	(67.8)	1.1
Non-cash investing activities:		
Deadstock commodity inventory transferred to property, plant and equipment	$ 8.3	$ 16.9
Impact of capital expenditure accruals on property, plant and equipment	80.0	(16.8)
Transfers from materials and supplies inventory to property, plant and equipment	1.5	0.9
Contribution of property, plant and equipment to investment in unconsolidated affiliates.	1.0	—
Change in ARO liability and property, plant and equipment due to revised cash flow estimate	3.1	(9.1)
Non-cash financing activities:		
Reduction of Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	$ 4.6	$ 4.9
Accrued tax withholding obligations	1.5	—
Allocation of Series A Preferred Stock net book value of BCF to additional paid-in capital	—	614.4
Accrued deemed dividends of Series A Preferred Stock	12.5	6.5
Change in accrued dividends of Series A Preferred Stock	—	22.9
Impact of accounting standard adoption recorded in retained earnings	56.1	—
Accrued distribution to noncontrolling interests	0.3	—
Non-cash balance sheet movements related to the Permian Acquisition (See Note 4 - Acquisitions and Divestitures):		
Contingent consideration recorded at the acquisition date	$ 416.3	$ —
Non-cash balance sheet movements related to the TRC/TRP Merger:		
Prepaid transaction costs reclassified in the additional paid-in capital	—	4.5
Issuance of common stock	—	0.1
Additional paid-in capital	—	3,120.0
Accumulated other comprehensive income	—	55.7
Noncontrolling interests	—	(4,119.7)
Deferred tax liability	—	943.9

(1) Interest capitalized on major projects was $4.1 million and $6.3 million for the six months ended June 30, 2017 and 2016.

Note 21 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business).

Our 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.

Our 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 our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segment and are predominantly located in Mont Belvieu and Galena Park, Texas; Lake Charles, Louisiana and Tacoma, Washington.

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

Reportable segment information is shown in the following tables:

	Three Months Ended June 30, 2017				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$177.5	$ 1,440.3	$6.0	$ —	$1,623.8
Fees from midstream services	132.3	111.6	—	—	243.9
	309.8	1,551.9	6.0	—	1,867.7
Intersegment revenues					
Sales of commodities	712.4	81.8	—	(794.2)	—
Fees from midstream services	1.4	7.1	—	(8.5)	—
	713.8	88.9	—	(802.7)	—
Revenues	$1,023.6	$ 1,640.8	$6.0	$ (802.7)	$1,867.7
Operating margin	$173.5	$ 112.4	$6.0	$ —	$291.9
Other financial information:					
Total assets (1)	$10,845.2	$ 2,918.5	$46.7	$ 108.0	$13,918.4
Goodwill	$256.6	$ —	$—	$ —	$256.6
Capital expenditures	$295.8	$ 136.1	$—	$ 2.6	$434.5

(1) Corporate assets at the segment level primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Three Months Ended June 30, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and	Total

				Eliminations	
Revenues					
Sales of commodities	$158.7	$ 1,135.6	$18.6	$ —	$1,312.9
Fees from midstream services	124.6	146.1	—	—	270.7
	283.3	1,281.7	18.6	—	1,583.6
Intersegment revenues					
Sales of commodities	468.6	52.7	—	(521.3)	—
Fees from midstream services	1.8	4.4	—	(6.2)	—
	470.4	57.1	—	(527.5)	—
Revenues	$753.7	$ 1,338.8	$18.6	$ (527.5)	$1,583.6
Operating margin	$139.1	$ 141.8	$18.6	$ —	$299.5
Other financial information:					
Total assets (1)	$10,168.0	$ 2,644.4	$55.0	$ 132.7	$13,000.1
Goodwill	$393.0	$ —	$—	$ —	$393.0
Capital expenditures	$71.3	$ 42.7	$—	$ 0.9	$114.9

(1) Corporate assets at the segment level primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

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	Six Months Ended June 30, 2017				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$344.3	$ 3,132.5	$4.9	$ —	$3,481.7
Fees from midstream services	250.7	247.9	—	—	498.6
	595.0	3,380.4	4.9	—	3,980.3
Intersegment revenues					
Sales of commodities	1,425.5	157.2	—	(1,582.7)	—
Fees from midstream services	3.3	14.1	—	(17.4)	—
	1,428.8	171.3	—	(1,600.1)	—
Revenues	$2,023.8	$ 3,551.7	$4.9	$ (1,600.1)	$3,980.3
Operating margin	$351.1	$ 242.4	$4.9	$ (0.1)	$598.3
Other financial information:					
Total assets (1)	$10,845.2	$ 2,918.5	$46.7	$ 108.0	$13,918.4
Goodwill	$256.6	$ —	$—	$ —	$256.6
Capital expenditures	$434.7	$ 171.0	$—	$ 3.4	$609.1
Business acquisition	$987.1	$ —	$—	$ —	$987.1

(1) Corporate assets at the segment level primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Six Months Ended June 30, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$269.0	$ 2,169.3	$45.7	$ —	$2,484.0
Fees from midstream services	240.4	301.6	—	—	542.0
	509.4	2,470.9	45.7	—	3,026.0
Intersegment revenues					
Sales of commodities	881.0	100.0	—	(981.0)	—
Fees from midstream services	3.9	8.5	—	(12.4)	—
	884.9	108.5	—	(993.4)	—
Revenues	$1,394.3	$ 2,579.4	$45.7	$ (993.4)	$3,026.0
Operating margin	$254.7	$ 298.5	$45.7	$ (0.1)	$598.8
Other financial information:					
Total assets (1)	$10,168.0	$ 2,644.4	$55.0	$ 132.7	$13,000.1
Goodwill	$393.0	$ —	$—	$ —	$393.0
Capital expenditures	$174.2	$ 115.9	$—	$ 1.7	$291.8

(1) Corporate assets at the segment level primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Sales of commodities:				
Natural gas	$496.0	$309.5	$976.9	$636.4
NGL	1,034.3	923.5	2,349.0	1,708.9
Condensate	47.4	39.0	91.0	61.2
Petroleum products	40.1	22.3	59.9	31.8
Derivative activities	6.0	18.6	4.9	45.7
	1,623.8	1,312.9	3,481.7	2,484.0
Fees from midstream services:				
Fractionating and treating	32.0	31.5	63.0	61.6
Storage, terminaling, transportation and export	72.9	108.2	172.7	226.7
Gathering and processing	122.7	114.0	230.5	219.0
Other	16.3	17.0	32.4	34.7
	243.9	270.7	498.6	542.0
Total revenues	$1,867.7	$1,583.6	$3,980.3	$3,026.0

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Reconciliation of operating margin to net income (loss):				
Operating margin	$ 291.9	$ 299.5	$ 598.3	$ 598.8
Depreciation and amortization expenses	(203.4)	(186.1)	(394.6)	(379.6)
General and administrative expenses	(51.0)	(47.0)	(99.6)	(92.2)
Goodwill impairment	—	—	—	(24.0)
Interest expense, net	(62.1)	(71.4)	(125.1)	(124.3)
Other, net	(10.8)	(7.9)	(53.8)	10.9
Income tax (expense) benefit	106.0	(1.7)	34.9	(4.8)
Net income (loss)	$ 70.6	$ (14.6)	$ (39.9)	$ (15.2)

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management’s Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2016 (“Annual Report”), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. Targa is a leading provider of midstream services and is one of the largest independent midstream energy companies in North America. We own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets.

On February 17, 2016, TRC completed its acquisition of all of the outstanding common units of Targa Resources Partners LP (“the Partnership” or “TRP”) pursuant to the Agreement and Plan of Merger (the “TRC/TRP Merger Agreement” and such transaction, the “TRC/TRP Merger” or “Buy-in Transaction”). We issued 104,525,775 shares of common stock in exchange for all of the outstanding common units of the Partnership that we previously did not own, which were listed on the New York Stock Exchange (“NYSE”) under the symbol “NGLS” prior to the consummation of the TRC/TRP Merger. As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The Partnership’s 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Preferred Units”) that were issued in October 2015 remain outstanding as limited partner interests in TRP and continue to trade on the NYSE under the symbol “NGLS PRA”.

As we continue to control the Partnership, the change in our ownership interest as a result of the TRC/TRP Merger was accounted for as an equity transaction and no gain or loss was recognized in our Consolidated Statements of Operations related to the Buy-in Transaction. The equity interests in TRP (which are consolidated in our financial statements) that were owned by the public prior to February 17, 2016 are reflected within “noncontrolling interests” in our Consolidated Balance Sheets for periods prior to the merger date. The earnings recorded by TRP that were attributed to its common units held by the public prior to February 17, 2016 are reflected within “Net income attributable to noncontrolling interests” in our Consolidated Statements of Operations for periods prior to the merger date.

Our Operations

We are engaged in the business of:

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

To provide these services, we operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business).

Our 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.

Our 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, fractionating, terminaling, transporting and marketing of NGLs and NGL products, including services to LPG exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses.

Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segment and are predominantly located in Mont Belvieu and Galena Park, Texas; Lake Charles, Louisiana and Tacoma, Washington.

Other contains the results (including any hedge ineffectiveness) of our commodity derivative activities that are included in operating margin.

Recent Developments

Gathering and Processing Segment Expansion

Permian Acquisition

On March 1, 2017, we completed the purchase of 100% of the membership interests of Outrigger Delaware Operating, LLC, Outrigger Southern Delaware Operating, LLC (together “New Delaware”) and Outrigger Midland Operating, LLC (“New Midland” and together with New Delaware, the “Permian Acquisition”).

We paid $484.1 million in cash at closing on March 1, 2017, and paid an additional $90.0 million in cash on May 30, 2017 (collectively, the "initial purchase price"). Subject to certain performance-linked measures and other conditions, additional cash of up to $935.0 million may be payable to the sellers of New Delaware and New Midland in potential earn-out payments that may occur in 2018 and 2019. The potential earn-out payments will be based upon a multiple of realized gross margin from contracts that existed on March 1, 2017.

New Delaware's gas gathering and processing and crude gathering assets are located in Loving, Winkler, Pecos and Ward counties. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. The New Delaware assets include 70 MMcf/d of processing capacity and an uninstalled 60 MMcf/d plant, known as the Oahu Plant, which we are in the process of installing in the Delaware Basin with expectations of commencing operations in late 2017. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Delaware system.

New Midland's gas gathering and processing and crude gathering assets are located in Howard, Martin and Borden counties. The operations are backed by producer dedications of more than 105,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 13 years. The New Midland assets include 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Midland system.

New Delaware's gas gathering and processing assets were connected to our Sand Hills system in the first quarter of 2017, and we expect that New Midland's gas gathering and processing assets will be connected to our existing WestTX system during 2017. We believe connecting the acquired assets to our legacy Permian footprint creates operational and capital synergies, and will afford enhanced flexibility in serving our producer customers.

Additional Permian System Processing Capacity

In November 2016, we announced plans to restart the idled 45 MMcf/d Benedum cryogenic processing plant and to add 20 MMcf/d of capacity at our Midkiff Plant in our WestTX system. The Benedum Plant was idled in September 2014 after the start-up of the 200 MMcf/d Edward Plant, and was brought back online in the first quarter of 2017. The addition of 20 MMcf/d of capacity at our Midkiff Plant was completed in the second quarter of 2017 and increased overall plant capacity of the Midkiff/Consolidator Plant complex in Reagan County, Texas from 210 MMcf/d to 230 MMcf/d. Also in November 2016, we announced plans to build the 200 MMcf/d Joyce Plant, which is expected to be completed in the first quarter of 2018. We expect total net growth capital expenditures for the Joyce Plant to be approximately $80 million.

In May 2017, we announced plans to build a new plant and expand the gathering footprint of our Permian Midland system in the Midland Basin. This project includes a new 200 MMcf/d cryogenic processing plant, known as the Johnson Plant, which is expected to begin operations in the third quarter of 2018. We expect total net growth capital expenditures for the Johnson Plant to be approximately $100 million.

Also in May 2017, we announced plans to build a new plant and expand the gathering footprint of our Permian Delaware system in the Delaware Basin. This project includes a new 250 MMcf/d cryogenic processing plant, known as the Wildcat Plant, which is expected to begin operations in the second quarter of 2018. We expect total net growth capital expenditures for the Wildcat Plant to be approximately $130 million.

Eagle Ford Shale Natural Gas Gathering and Processing Joint Ventures

In October 2015, we announced that we had entered into the Carnero Joint Ventures with Sanchez Energy Corporation (“Sanchez”) to construct the 200 MMcf/d Raptor Plant and approximately 45 miles of associated pipelines. In July 2016, Sanchez sold its interest in the gathering joint venture to Sanchez Midstream Partners, L.P. (“SNMP”), formerly known as Sanchez Production Partners, L.P., and in November 2016, sold its interest in the processing joint venture to SNMP. Through the Carnero Joint Ventures, we indirectly own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect SNMP's Catarina gathering system to the plant. We hold the capacity on the high pressure gathering pipelines, and pay the gathering joint venture fees for transportation.

The Raptor Plant began operations in the second quarter of 2017, and is capable of processing 200 MMcf/d. In February 2017, we announced the addition of compression to increase the processing capacity of the Raptor Plant to 260 MMcf/d, which we expect to be completed in the third quarter of 2017. The Raptor Plant accommodates growing production from Sanchez’s premier Eagle Ford Shale acreage position in Dimmit, La Salle and Webb Counties, Texas and from other third party producers. The plant and high pressure gathering pipelines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We manage operations of the high pressure gathering lines and the plant. Prior to the plant being placed in service, we benefited from Sanchez natural gas volumes that were processed at our Silver Oak facilities in Bee County, Texas.

Eagle Ford Shale Acquisition of Flag City Natural Gas Processing Plant

In May 2017, we acquired a 150 MMcf/d natural gas processing plant (the “Flag City Plant”) and associated assets from subsidiaries of Boardwalk Pipeline Partners, L.P. (“Boardwalk”) for $60 million, subject to customary closing adjustments. The gas processing activities under the Flag City Plant contracts have been transferred to our Silver Oak facilities. We shut down the Flag City Plant and are moving the plant and its component parts to other Targa locations.

Badlands

During 2017, we expect to invest approximately $150 million to expand our crude gathering and natural gas processing business in the Williston Basin, North Dakota. The expansion includes the addition of pipelines, LACT units, compression and other infrastructure to support continued growth in producer activity.

Sale of Venice Gathering System, L.L.C.

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C. (“VESCO”), we have operated the Venice Gas Plant and the Venice gathering system. On April 4, 2017, VESCO entered into a purchase and sale agreement with Rosefield Pipeline Company, LLC, an affiliate of Arena Energy, LP, to sell its 100% ownership interests in Venice Gathering System, L.L.C. (“VGS”), a Delaware limited liability company engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the Federal Energy Regulatory Commission (“FERC”), for approximately $0.4 million in cash. Additionally, the VGS asset retirement obligations were assumed by the buyer. VGS owns and operates a natural gas gathering system in the Gulf of Mexico. Historically, VGS has been reported in our Gas Gathering and Processing segment. After the sale of VGS, we continue to operate the Venice Gas Plant through our ownership in VESCO. Targa Midstream Services LLC will continue to operate the Venice gathering system for up to four months after closing pursuant to a Transition Services Agreement with VGS.

Downstream Segment Expansion

Grand Prix NGL Pipeline

On May 25, 2017, we announced plans to construct a new common carrier NGL pipeline (“Grand Prix”), which will transport volumes from the Permian Basin and from our North Texas system to our fractionation and storage complex in the NGL market hub at Mont Belvieu. Grand Prix will be supported by our plant volumes and other third party customer commitments, and is expected to be in service in the second quarter of 2019. The initial capacity of the pipeline from the Permian Basin will be approximately 300 MBbl/d and will be expandable to 550 MBbl/d with the addition of pump stations. We expect total net growth capital expenditures for Grand Prix to be approximately $1.3 billion, with approximately $330 million of spending in 2017.

Financing Activities

On January 26, 2017, we completed a public offering of 9,200,000 shares of common stock (including underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds after underwriting discounts, commissions and other expenses of $524.2 million. We used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes.

On February 23, 2017, we amended the Partnership's account receivable securitization facility ("Securitization Facility") to increase the facility size to $350.0 million from $275.0 million.

On March 14, 2017, we used borrowings under our senior secured revolving credit facility ("TRC Revolver") to repay in full the $160.0 million outstanding balance on our senior secured term loan.

During the six months ended June 30, 2017, we sold 4,521,310 shares under the December 2016 EDA associated with our ATM program, resulting in net proceeds of $257.2 million.

In May 2017, the Partnership issued notice of full redemption to the trustee of its 6 % Senior Notes due August 2022 ("6 % Senior Notes"). The redemption price was 103.188% of the principal amount. The $278.7 million principal amount outstanding was redeemed on June 26, 2017 for a total redemption payment of $287.6 million, excluding accrued interest.

On May 9, 2017, we entered into an equity distribution agreement under the May 2016 Shelf (the "May 2017 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock. For the six months ended June 30, 2017, no shares of common stock have been issued under the May 2017 EDA.

On June 1, 2017, we completed a public offering of 17,000,000 shares of our common stock at a price to the public of $46.10, providing net proceeds after underwriting discounts, commissions and other expenses of $777.3 million. We used the net proceeds from this public offering to fund a portion of the capital expenditures related to the construction of Grand Prix, repay outstanding borrowings under the our credit facilities, redeem the Partnership's 6 % Senior Notes, and for general corporate purposes.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see “Recent Accounting Pronouncements” included within Note 3 – Significant Accounting Policies in our Consolidated Financial Statements.

How We Evaluate Our Operations

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

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

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval.

Gross Margin

We define gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by our 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

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

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

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

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

Adjusted EBITDA

We define 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 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015; non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our 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 our 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 our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Distributable Cash Flow

We define distributable cash flow as 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 us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our board of directors) to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our 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 our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly 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 our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Our Non-GAAP Financial Measures

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ 57.6	$ (23.2)	$ (61.7)	$ (25.9)
Net income (loss) attributable to noncontrolling interests	13.0	8.6	21.8	10.7
Net income (loss)	70.6	(14.6)	(39.9)	(15.2)
Depreciation and amortization expense	203.4	186.1	394.6	379.6
General and administrative expense	51.0	47.0	99.6	92.2
Goodwill impairment	—	—	—	24.0
Interest expense, net	62.1	71.4	125.1	124.3
Income tax expense (benefit)	(106.0)	1.7	(34.9)	4.8
(Gain) loss on sale or disposition of assets	0.1	—	16.2	0.9
(Gain) loss from financing activities	10.7	3.3	16.5	(21.4)
Other, net	—	4.6	21.1	9.6
Operating margin	291.9	299.5	598.3	598.8
Operating expenses	155.2	138.9	307.2	271.0
Gross margin	$ 447.1	$ 438.4	$ 905.5	$ 869.8

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ 57.6	$ (23.2)	$ (61.7)	$ (25.9)
Impact of TRC/TRP Merger on NCI	—	—	—	(3.8)
Income attributable to TRP preferred limited partners	2.8	2.8	5.6	5.6
Interest expense, net	62.1	71.4	125.1	124.3
Income tax expense (benefit)	(106.0)	1.7	(34.9)	4.8
Depreciation and amortization expense	203.4	186.1	394.6	379.6
Goodwill impairment	—	—	—	24.0
(Gain) loss on sale or disposition of assets	0.1	—	16.2	0.9
(Gain) loss from financing activities	10.7	3.3	16.5	(21.4)
(Earnings) loss from unconsolidated affiliates	4.2	4.4	16.8	9.2
Distributions from unconsolidated affiliates and preferred partner interests, net	6.2	3.0	10.4	8.8
Change in contingent consideration included in Other expense	(2.1)	—	1.2	—
Compensation on equity grants	10.7	7.2	21.5	15.2
Transaction costs related to business acquisitions	0.1	—	5.2	—
Splitter Agreement (1)	10.8	—	21.5	—
Risk management activities	1.6	6.6	5.2	12.6
Noncontrolling interests adjustments (2)	(4.3)	(6.2)	(8.6)	(12.1)
TRC Adjusted EBITDA	$ 257.9	$ 257.1	$ 534.6	$ 521.8
Distributions to TRP preferred limited partners	(2.8)	(2.8)	(5.6)	(5.6)
Splitter Agreement (1)	(10.8)	—	(21.5)	—
Interest expense on debt obligations (3)	(56.6)	(65.9)	(115.5)	(135.6)
Cash tax (expense) benefit (4)	31.4	—	46.7	—
Maintenance capital expenditures	(23.3)	(20.2)	(49.0)	(35.2)
Noncontrolling interests adjustments of maintenance capex	0.2	1.4	0.5	2.2
Distributable Cash Flow	$ 196.0	$ 169.6	$ 390.2	$ 347.6

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(1) In Adjusted EBITDA, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the condensate splitter agreement over the four quarters following receipt. In Distributable Cash Flow, the Splitter Agreement adjustment represents the amounts necessary to reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA.

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

(3) Excludes amortization of interest expense.

(4) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is being recognized over the periods between the Q3 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before Q4 2017, was received in Q2 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.

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Consolidated Results of Operations

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

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016		Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 1,623.8	$ 1,312.9	$ 310.9	24 %	$ 3,481.7	$ 2,484.0	$ 997.7	40 %
Fees from midstream services	243.9	270.7	(26.8)	(10 %)	498.6	542.0	(43.4)	(8 %)
Total revenues	1,867.7	1,583.6	284.1	18 %	3,980.3	3,026.0	954.3	32 %
Product purchases	1,420.6	1,145.2	275.4	24 %	3,074.8	2,156.2	918.6	43 %
Gross margin (1)	447.1	438.4	8.7	2 %	905.5	869.8	35.7	4 %
Operating expenses	155.2	138.9	16.3	12 %	307.2	271.0	36.2	13 %
Operating margin (1)	291.9	299.5	(7.6)	(3 %)	598.3	598.8	(0.5)	—
Depreciation and amortization expense	203.4	186.1	17.3	9 %	394.6	379.6	15.0	4 %
General and administrative expense	51.0	47.0	4.0	9 %	99.6	92.2	7.4	8 %
Goodwill impairment	—	—	—	—	—	24.0	(24.0)	(100%)
Other operating (income) expense	0.3	0.1	0.2	200%	16.5	1.1	15.4	NM
Income from operations	37.2	66.3	(29.1)	(44 %)	87.6	101.9	(14.3)	(14 %)
Interest expense, net	(62.1)	(71.4)	9.3	13 %	(125.1)	(124.3)	(0.8)	1 %
Equity earnings (loss)	(4.2)	(4.4)	0.2	5 %	(16.8)	(9.2)	(7.6)	83 %
Gain (loss) from financing activities	(10.7)	(3.3)	(7.4)	224%	(16.5)	21.4	(37.9)	(177%)
Other income (expense), net	4.4	(0.1)	4.5	NM	(4.0)	(0.2)	(3.8)	NM
Income tax (expense) benefit	106.0	(1.7)	107.7	NM	34.9	(4.8)	39.7	NM
Net income (loss)	70.6	(14.6)	85.2	NM	(39.9)	(15.2)	(24.7)	163 %
Less: Net income attributable to noncontrolling interests	13.0	8.6	4.4	51 %	21.8	10.7	11.1	104 %
Net income (loss) attributable to Targa Resources Corp.	57.6	(23.2)	80.8	NM	(61.7)	(25.9)	(35.8)	138 %
Dividends on Series A preferred stock	22.9	22.9	—	—	45.8	26.7	19.1	72 %
Deemed dividends on Series A preferred stock	6.3	6.5	(0.2)	(3 %)	12.5	6.5	6.0	92 %
Net income (loss) attributable to common shareholders	$ 28.4	$ (52.6)	$ 81.0	154%	$ (120.0)	$ (59.1)	$ (60.9)	103 %
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	$ 257.9	$ 257.1	$ 0.8	—	$ 534.6	$ 521.8	$ 12.8	2 %
Distributable cash flow (1)	196.0	169.6	26.4	16 %	390.2	347.6	42.6	12 %
Capital expenditures	434.5	114.9	319.6	278%	609.1	291.8	317.3	109 %

Business acquisition (2)	—	—	—	—	987.1	—	987.1	—
Operating statistics: (3)								
Crude oil gathered, Badlands, MBbl/d	112.5	105.2	7.3	7 %	113.0	106.6	6.4	6 %
Crude oil gathered, Permian, MBbl/d (4)	28.6	—	28.6	—	18.9	—	18.9	—
Plant natural gas inlet, MMcf/d (5) (6)	3,391.2	3,511.4	(120.2)	(3 %)	3,304.6	3,452.1	(147.5)	(4 %)
Gross NGL production, MBbl/d	321.2	321.0	0.2	—	305.0	302.8	2.2	1 %
Export volumes, MBbl/d (7)	155.3	181.3	(26.0)	(14 %)	186.2	181.2	5.0	3 %
Natural gas sales, BBtu/d (6) (8)	1,957.3	1,958.4	(1.1)	—	1,885.7	1,966.5	(80.8)	(4 %)
NGL sales, MBbl/d (8)	473.9	516.8	(42.9)	(8 %)	503.6	532.3	(28.7)	(5 %)
Condensate sales, MBbl/d	12.1	11.4	0.7	6 %	11.5	10.4	1.1	11 %

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(1) Gross margin, operating margin, adjusted EBITDA, and distributable cash flow are non-GAAP financial measures and are discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."
(2) Includes the preliminary acquisition date fair value of the potential earn-out payments of $416.3 million due in 2018 and 2019.
(3) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(7) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine Terminal that are destined for international markets.
(8) Includes the impact of intersegment eliminations.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

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

The increase in commodity sales was primarily due to higher commodity prices ($386.8 million) and higher petroleum products and condensate volumes ($13.7 million), partially offset by decreased NGL sales volumes ($77.0 million) and the impact of hedge settlements ($12.6 million). Fee-based and other revenues decreased primarily due to lower export fees and volumes, partially offset by higher crude gathering and gas processing fees.

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

The higher gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating margin decreased as the increases in operating expenses more than offset the increases in gross margin. Operating expenses increased compared to 2016 due to higher fuel and power and higher maintenance in the Logistics and Marketing segment and the impact of the Permian Acquisition and other plant and system expansions in the Gathering and Processing segment. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expense reflects the impact of the Permian Acquisition and other growth investments, partially offset by the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles.

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

Net interest expense decreased primarily due to the impact of lower average outstanding borrowings during 2017.

During 2017, we recorded a loss from financing activities of $10.7 million on the redemption of the outstanding 6 % Senior Notes, whereas in 2016 we recorded a loss of $3.3 million on open debt market repurchases.

The income tax benefit for the three months ended June 30, 2017 is the result of the difference between the annual effective tax rate used to calculate income tax (expense) benefit for the three months ended March 31, 2017 and the statutory rate used to calculate income tax (expense) benefit for the six months ended June 30, 2017. For additional discussion of the basis for the calculation of the income tax benefit for the six months ended June 30, 2017, see the income tax explanation under the Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.

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

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

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The increase in commodity sales was primarily due to higher commodity prices ($1,148.6 million) and higher petroleum products and condensate volumes ($18.3 million), partially offset by decreased NGL and natural gas sales volumes ($131.1 million) and the impact of hedge settlements ($38.1 million). Fee-based and other revenues decreased primarily due to lower export fees.

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

The higher gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating margin was relatively flat as compared to 2016 as the increases in gross margin were offset by the increases in operating expenses. Operating expenses increased compared to 2016 due to higher maintenance, higher fuel and power, and higher labor in the Logistics and Marketing segment and plant and system expansions. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expense reflects four months of operations from the Permian Acquisition in 2017 and the impact of other growth investments, primarily CBF Train 5 which went into service in the second quarter of 2016, partially offset by the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles.

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

We recognized an impairment of goodwill in the first quarter of 2016 of $24.0 million to finalize the 2015 provisional impairment of goodwill. The impairment charge related to goodwill acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively, the “Atlas mergers”).

Other operating (income) expense in 2017 includes the loss due to the reduction in the carrying value of our ownership interest in the Venice Gathering System in connection with the April 4, 2017 sale.

Net interest expense in 2017 was flat as compared with 2016. Higher non-cash interest expense related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date was offset by lower average outstanding borrowings during 2017.

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

During 2017, we recorded a loss from financing activities of $16.5 million on the redemption of the outstanding 6 % Senior Notes and the repayment of the outstanding balance on our senior secured term loan, whereas in 2016 we recorded a gain of $21.4 million on open market debt repurchases.

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

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

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

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)				
Three Months Ended:					
June 30, 2017	$ 173.5	$ 112.4	$ 6.0	$ —	$ 291.9
June 30, 2016	139.1	141.8	18.6	—	299.5
Six Months Ended:					
June 30, 2017	$ 351.1	$ 242.4	$ 4.9	$ (0.1)	$ 598.3
June 30, 2016	254.7	298.5	45.7	(0.1)	598.8

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Gathering and Processing Segment

	Three Months Ended June 30,				Six Months Ended June 30,			
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
Gross margin	$ 264.2	$ 222.4	$ 41.8	19 %	$ 527.4	$ 416.5	$ 110.9	27 %
Operating expenses	90.7	83.3	7.4	9 %	176.3	161.8	14.5	9 %
Operating margin	$ 173.5	$ 139.1	$ 34.4	25 %	$ 351.1	$ 254.7	$ 96.4	38 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	311.6	259.2	52.4	20 %	293.7	251.3	42.4	17 %
WestTX	541.6	481.4	60.2	13 %	526.5	464.7	61.8	13 %
Total Permian Midland	853.2	740.6	112.6		820.2	716.0	104.2	
Sand Hills (4)	181.7	135.8	45.9	34 %	160.7	143.4	17.3	12 %
Versado	196.5	168.8	27.7	16 %	197.5	174.4	23.1	13 %
Total Permian Delaware	378.2	304.6	73.6		358.2	317.8	40.4	
Total Permian	1,231.4	1,045.2	186.2		1,178.4	1,033.8	144.6	
SouthTX	222.6	265.4	(42.8)	(16%)	197.4	220.5	(23.1)	(10%)
North Texas	277.1	327.5	(50.4)	(15%)	279.8	327.5	(47.7)	(15%)
SouthOK	479.0	470.7	8.3	2 %	459.8	464.3	(4.5)	(1 %)
WestOK	387.4	445.6	(58.2)	(13%)	390.3	466.3	(76.0)	(16%)
Total Central	1,366.1	1,509.2	(143.1)		1,327.3	1,478.6	(151.3)	
Badlands (5)	52.2	51.2	1.0	2 %	49.1	52.5	(3.4)	(6 %)
Total Field	2,649.7	2,605.6	44.1		2,554.8	2,564.9	(10.1)	
Coastal	741.6	905.8	(164.2)	(18%)	749.9	887.2	(137.3)	(15%)
Total	3,391.3	3,511.4	(120.1)	(3 %)	3,304.7	3,452.1	(147.4)	(4 %)
Gross NGL production, MBbl/d (3)								
SAOU (4)	37.9	32.2	5.7	18 %	35.6	30.7	4.9	16 %
WestTX	74.9	61.9	13.0	21 %	70.7	57.2	13.5	24 %
Total Permian Midland	112.8	94.1	18.7		106.3	87.9	18.4	
Sand Hills (4)	20.0	14.1	5.9	42 %	17.4	14.9	2.5	17 %
Versado	22.9	20.2	2.7	13 %	23.0	21.1	1.9	9 %
Total Permian Delaware	42.9	34.3	8.6		40.4	36.0	4.4	
Total Permian	155.7	128.4	27.3		146.7	123.9	22.8	
SouthTX	23.5	31.4	(7.9)	(25%)	20.1	27.3	(7.2)	(26%)
North Texas	31.1	37.0	(5.9)	(16%)	31.5	36.3	(4.8)	(13%)
SouthOK	38.5	47.3	(8.8)	(19%)	39.7	37.6	2.1	6 %
WestOK	23.5	29.7	(6.2)	(21%)	23.1	28.3	(5.2)	(18%)
Total Central	116.6	145.4	(28.8)		114.4	129.5	(15.1)	

Badlands	7.7	7.0	0.7	10 %	6.6	7.3	(0.7)	(10%)
Total Field	280.0	280.8	(0.8)		267.7	260.7	7.0	
Coastal	41.2	40.1	1.1	3 %	37.3	42.2	(4.9)	(12%)
Total	321.2	320.9	0.3	—	305.0	302.9	2.1	1 %
Crude oil gathered, Badlands, MBbl/d	112.5	105.2	7.3	7 %	113.0	106.6	6.4	6 %
Crude oil gathered, Permian, MBbl/d (4)	28.6	—	28.6	—	18.9	—	18.9	—
Natural gas sales, BBtu/d (3)	1,655.2	1,605.8	49.6	3 %	1,601.6	1,646.5	(44.9)	(3 %)
NGL sales, MBbl/d	249.2	256.1	(6.9)	(3 %)	238.4	237.7	0.7	—
Condensate sales, MBbl/d	12.1	10.9	1.3	12 %	11.4	10.2	1.3	13 %
Average realized prices (6):								
Natural gas, $/MMBtu	2.70	1.64	1.06	65 %	2.79	1.70	1.09	64 %
NGL, $/gal	0.46	0.36	0.10	28 %	0.48	0.32	0.16	50 %
Condensate, $/Bbl	42.74	37.94	4.81	13 %	43.79	32.21	11.58	36 %

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(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents our undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.
(5) Badlands natural gas inlet represents the total wellhead gathered volume.
(6) Average realized prices exclude the impact of hedging activities presented in Other.

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

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition in 2017. Inlet volumes for Field Gathering and Processing were higher primarily due to increases at WestTX, SAOU, Sand Hills and Versado, partially offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower margins, more than offset the Field Gathering and Processing inlet volume increase. Higher NGL production in the Permian region was more than offset by lower NGL production in the other areas. Natural gas sales increased primarily due to increased Field Gathering and Processing inlet volumes. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total Badlands crude oil gathered volumes and natural gas volumes increased primarily due to system expansions.

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

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition in 2017. Field Gathering and Processing inlet volume increases in the Permian region, specifically at WestTX, SAOU, Versado and Sand Hills, were offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower margins than does Field Gathering and Processing, accounted for over 93% of the overall inlet volume decrease. Despite overall lower inlet volumes, NGL production and NGL sales increased slightly primarily due to increased plant recoveries including additional ethane recovery. Natural gas sales decreased due to lower inlet volumes and increased ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total crude oil gathered in the Badlands increased due to system expansions. Badlands natural gas volumes decreased primarily due to the impact of the severe winter weather in the first quarter of 2017.

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

Gross Operating Statistics Compared to Actual Reported

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

Operating statistics:	Three Months Ended June 30, 2017			
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU (4)	311.6	100 %	311.6	311.6
WestTX (5) (6)	743.9	73 %	541.6	541.6
Total Permian Midland	1,055.5		853.2	853.2
Sand Hills (4)	181.7	100 %	181.7	181.7
Versado (7)	196.5	100 %	196.5	196.5
Total Permian Delaware	378.2		378.2	378.2
Total Permian	1,433.7		1,231.4	1,231.4
SouthTX	222.6	Varies (8) (9)	199.1	222.6
North Texas	277.1	100 %	277.1	277.1
SouthOK	479.0	Varies (10)	382.6	479.0
WestOK	387.4	100 %	387.4	387.4
Total Central	1,366.1		1,246.2	1,366.1
Badlands (11)	52.2	100 %	52.2	52.2
Total Field	2,852.0		2,529.8	2,649.7
Gross NGL production, MBbl/d (2)				
SAOU (4)	37.9	100 %	37.9	37.9
WestTX (5) (6)	102.9	73 %	74.9	74.9
Total Permian Midland	140.8		112.8	112.8
Sand Hills (4)	20.0	100 %	20.0	20.0
Versado (7)	22.9	100 %	22.9	22.9
Total Permian Delaware	42.9		42.9	42.9
Total Permian	183.7		155.7	155.7
SouthTX	23.5	Varies (8) (9)	20.8	23.5
North Texas	31.1	100 %	31.1	31.1
SouthOK	38.5	Varies (10)	31.4	38.5
WestOK	23.5	100 %	23.5	23.5
Total Central	116.6		106.8	116.6
Badlands	7.7	100 %	7.7	7.7
Total Field	308.0		270.2	280.0

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

	Three Months Ended June 30, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU	259.2	100 %	259.2	259.2
WestTX (4)	661.2	73 %	481.4	481.4
Total Permian Midland	920.4		740.6	740.6
Sand Hills	135.8	100 %	135.8	135.8
Versado (5)	168.8	63 %	106.3	168.8
Total Permian Delaware	304.6		242.1	304.6
Total Permian	1,225.0		982.7	1,045.2
SouthTX	265.4	Varies (6)	251.9	265.4
North Texas	327.5	100 %	327.5	327.5
SouthOK	470.7	Varies (7)	393.7	470.7
WestOK	445.6	100 %	445.6	445.6
Total Central	1,509.2		1,418.7	1,509.2
Badlands (8)	51.2	100 %	51.2	51.2
Total Field	2,785.4		2,452.6	2,605.6
Gross NGL production, MBbl/d (2)				
SAOU	32.2	100 %	32.2	32.2
WestTX (4)	85.0	73 %	61.9	61.9
Total Permian Midland	117.2		94.1	94.1
Sand Hills	14.1	100 %	14.1	14.1
Versado (5)	20.2	63 %	12.7	20.2
Total Permian Delaware	34.3		26.8	34.3
Total Permian	151.5		120.9	128.4
SouthTX	31.4	Varies (6)	30.2	31.4
North Texas	37.0	100 %	37.0	37.0
SouthOK	47.3	Varies (7)	44.0	47.3
WestOK	29.7	100 %	29.7	29.7
Total Central	145.4		140.9	145.4
Badlands	7.0	100 %	7.0	7.0
Total Field	303.9		268.8	280.8

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.

(3)

For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

(4) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.

(5) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.

(6) SouthTX includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we own 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.

(7) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(8) Badlands natural gas inlet represents the total wellhead gathered volume.

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Logistics and Marketing Segment

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016		Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016	
	(In millions)							
Gross margin	$ 176.9	$ 197.6	$ (20.7)	(10%)	$ 373.2	$ 407.9	$ (34.7)	(9 %)
Operating expenses	64.5	55.8	8.7	16 %	130.8	109.4	21.4	20 %
Operating margin	$ 112.4	$ 141.8	$ (29.4)	(21%)	$ 242.4	$ 298.5	$ (56.1)	(19%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	338.5	329.8	8.7	3 %	321.8	312.7	9.1	3 %
LSNG treating volumes (2)	33.3	23.1	10.2	44 %	33.9	22.0	11.9	54 %
Benzene treating volumes (2)	22.1	23.1	(1.0)	(4 %)	22.8	22.0	0.8	4 %
Export volumes, MBbl/d (4)	155.3	181.3	(26.0)	(14%)	186.2	181.2	5.0	3 %
NGL sales, MBbl/d	439.4	463.6	(24.2)	(5 %)	470.5	472.8	(2.3)	—
Average realized prices:								
NGL realized price, $/gal	$ 0.58	$ 0.48	$ 0.10	21 %	$ 0.62	$ 0.44	$ 0.18	41 %

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components 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 our Galena Park Marine Terminal that are destined for international markets.

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

Logistics and Marketing gross margin decreased due to lower LPG export margin partially offset by higher fractionation margin, higher terminaling and storage throughput, and higher treating margin. LPG export margin decreased due to lower fees and volumes. Fractionation margin increased due to higher fees, an increase in system product gains and higher supply volume. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). Treating margin increased slightly due to higher volumes partially offset by lower fees.

Operating expenses increased primarily due to higher fuel and power, which are largely passed through, and higher labor primarily associated with Train 5.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The six month gross margin results were impacted by the same factors as discussed above for the quarter except that LPG export volumes were higher.

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

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	2017 vs. 2016	2017	2016	2017 vs. 2016
	(In millions)					
Gross margin	$6.0	$18.6	$(12.6)	$4.9	$45.7	$(40.8)
Operating margin	$6.0	$18.6	$(12.6)	$4.9	$45.7	$(40.8)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash flow hedges. The primary purpose of our commodity risk management activities is to mitigate a portion of the impact of commodity prices on our operating cash flow. We have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing Operations that result from percent of proceeds/liquids processing arrangements. Because we are essentially forward-selling a portion of our future plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

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

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	15.5	$ 0.16	$ 2.5	10.7	$ 1.27	$ 13.6	$ (11.1)
NGL (MMgal)	59.4	0.01	0.8	13.1	0.09	1.0	(0.2)
Crude oil (MBbl)	0.3	6.93	2.3	0.3	15.72	4.4	(2.1)
Non-hedge accounting (2)			0.4			(0.1)	0.5
Ineffectiveness (3)			-			(0.3)	0.3
			$ 6.0			$ 18.6	$ (12.6)

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	26.0	$ 0.09	$ 2.6	20.2	$ 1.33	$ 26.9	$ (24.3)
NGL (MMgal)	102.7	(0.01)	(1.1)	27.3	0.18	5.0	(6.1)
Crude oil (MBbl)	0.6	6.29	3.5	0.5	23.82	11.5	(8.0)
Non-hedge accounting (2)			(0.3)			2.6	(2.9)
Ineffectiveness (3)			0.2			(0.3)	0.5
			$ 4.9			$ 45.7	$ (40.8)

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

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of February 27, 2015 (the "acquisition date"), were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $1.9 million and $4.9 million for the three and six months ended June 30, 2017 and $6.3 million and $15.1 million for the three and six months ended June 30, 2016, related to these novated contracts. From the acquisition date through June 30, 2017, we have received total derivative settlements of $99.5 million. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

Liquidity and Capital Resources

As of June 30, 2017, we had $98.7 million of "Cash and cash equivalents," on our Consolidated Balance Sheet. We believe our cash position, remaining borrowing capacity on our credit facilities (discussed below in "Short-term Liquidity"), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

After completion of the TRC/TRP Merger, our liquidity and capital resources have been managed on a consolidated basis. We have the ability to access the Partnership's liquidity, subject to the limitations set forth in the Partnership Agreement and any restrictions contained in the covenants of the Partnership's debt agreements, as well as the ability to contribute capital to the Partnership, subject to any restrictions contained in the covenants of our debt agreements.

On a consolidated basis, our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing our indebtedness and meeting our collateral requirements, and paying dividends declared by our board of directors will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control. These include commodity prices, weather and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Historically, dividends have been funded by the cash distributions we received from the Partnership. In connection with the TRC/TRP Merger, TRC acquired all of the outstanding TRP common units that TRC and its subsidiaries did not already own. As a result, we are entitled to the entirety of distributions made by the Partnership on its equity interests, other than those made to the TRP Preferred Unitholders. The actual amount we declare as dividends continues to depend on our consolidated financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects, compliance with our debt covenants and any other matters that our board of directors deems relevant.

The Partnership's debt agreements and obligations to its Preferred Unitholders may restrict or prohibit the payment of distributions if the Partnership is in default, threat of default, or arrears. In addition, so long as any shares of our Preferred Shares are outstanding, certain common stock distribution limitations exist. If the Partnership cannot make distributions to us, we may be limited in our ability, or unable, to pay dividends on our common stock.

On a consolidated basis, our main sources of liquidity and capital resources are internally generated cash flows from operations, borrowings under the TRC Revolver, the TRP Revolver, and the Securitization Facility, and access to debt and equity capital markets. For companies involved in hydrocarbon production, transportation and other oil and gas related services, the capital markets have experienced and may continue to experience volatility. Our exposure to adverse credit conditions includes our credit facilities, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity on a consolidated basis as of July 31, 2017, was:

	July 31, 2017 (In millions)		
	TRC	TRP	Consolidated Total
Cash on hand	$22.8	$150.1	$ 172.9
Total availability under the TRC Revolver	670.0	—	670.0
Total availability under the TRP Revolver	—	1,600.0	1,600.0
Total availability under the Securitization Facility	—	274.0	274.0
	692.8	2,024.1	2,716.9
Less: Outstanding borrowings under the TRC Revolver	(435.0)	—	(435.0)
Outstanding borrowings under the TRP Revolver	—	(150.0)	(150.0)
Outstanding borrowings under the Securitization Facility	—	(274.0)	(274.0)
Outstanding letters of credit under the TRP Revolver	—	(20.4)	(20.4)
Total liquidity	$257.8	$1,579.7	$ 1,837.5

Other potential capital resources associated with our existing arrangements include:

- Our right to request an additional $200 million in commitment increases under the TRC Revolver, subject to the terms therein. The TRC Revolver matures on February 27, 2020.
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Our right to request an additional $500 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on October 7, 2020.

- We may elect to pay dividends to Series A Preferred shareholders for any quarter with a paid-in-kind election ("PIK") through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of Series A and Series B Warrants would be issued.

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

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis, at the end of any given month, accounts receivable and payable that are tied to commodity sales and purchases are relatively balanced, with receivables from NGL and natural gas customers being offset by plant settlements payable to producers. The factors that typically cause overall

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variability in our reported total working capital are: (1) our cash position; (2) liquids inventory levels and valuation, which we closely manage; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Our working capital, exclusive of current debt obligations, decreased $94.8 million from December 31, 2016 to June 30, 2017. The major items contributing to this decrease were the increased capital accruals driven primarily by the Permian activity and the reclassification of a portion of the Permian Acquisition contingent consideration to current, the collection of an income tax refund, and a decrease in our net commodity receivables due to lower commodity revenue and reduced commodity purchases, partially offset by an increase in inventory due to price increases, an increase in our current net risk management position due to changes in the forward prices of commodities, and higher cash balances. The increase of $225.1 million in current debt obligations was due to reclassification of the remaining 5% Notes due January 2018 to short term.

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

Long-term Financing

Our long-term financing consists of common stock, common warrants, preferred stock and long-term debt obligations. On January 26, 2017, we completed a public offering of 9,200,000 shares of our common stock (including the shares sold pursuant to the underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds of $524.2 million. We used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes. On June 1, 2017, we completed a public offering of 17,000,000 shares of our common stock at a price to the public of $46.10, providing net proceeds after underwriting discounts, commissions and other expenses of $777.3 million. We used the net proceeds from this public offering to fund a portion of the capital expenditures related to the construction of Grand Prix, repay outstanding borrowings under the Company's credit facilities, redeem the Partnership's 6 % Senior Notes, and for general corporate purposes.

During 2017, under the December 2016 equity distribution agreement, we issued and sold through our sales agents 4,532,421 shares of common stock and received net proceeds of $257.2 million. As of July 30, 2017, we have $411.2 million remaining under our December 2016 equity distribution agreement and the full $750.0 million remaining under our May 2017 equity distribution agreement.

During 2016, 19,983,843 warrants were exercised and net settled for 11,336,856 shares of common stock. For the six months ended June 30, 2017, no detachable Warrants were exercised. As a result, Series A Warrants exercisable into a maximum of 67,392 shares of common stock and Series B Warrants exercisable into a maximum of 32,496 shares of common stock were outstanding as of June 30, 2017.

From time to time, we issue long-term debt securities, which we refer to as senior notes. Our senior notes issued to date, generally have similar terms other than interest rates, maturity dates and redemption premiums. As of June 30, 2017 and December 31, 2016, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $3,962.6 million and $4,641.8 million, respectively.

We consolidate the debt of the Partnership with that of our own; however, we do not have the contractual obligation to make interest or principal payments with respect to the debt of the Partnership. Our debt obligations do not restrict the ability of the Partnership to make distributions to us. Our Credit Agreement has restrictions and covenants that may limit our ability to pay dividends to our stockholders. See Note 10 – Debt Obligations for more information regarding our debt obligations.

The majority of our consolidated long-term debt is fixed rate borrowings; however, we have some exposure to the risk of changes in interest rates, primarily as a result of the variable rate borrowings under the TRC Revolver and the TRP Revolver. We may enter into interest rate hedges with the intent to mitigate the impact of changes in interest rates on cash flows. As of June 30, 2017, we do not have any interest rate hedges.

To date, we do not believe our and our subsidiaries' debt balances have adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt-related transactions, see Note 10 - Debt Obligations to our consolidated financial statements. For information about our interest rate risk, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

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Compliance with Debt Covenants

As of June 30, 2017, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

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

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

	Six Months Ended June 30,		
	2017	2016	2017 vs. 2016
	(In millions)		
Cash flows from operating activities:			
Cash received from customers	$4,109.5	$2,978.5	$1,131.0
Cash received from (paid to) derivative counterparties	9.9	51.1	(41.2)
Cash distributions from equity investments (1)	4.0	—	4.0
Cash outlays for:			
Product purchases	3,186.8	2,096.8	1,090.0
Operating expenses	332.0	256.9	75.1
General and administrative expense	94.6	75.3	19.3
Interest paid, net of amounts capitalized (2)	109.2	142.2	(33.0)
Income taxes paid, net of refunds	(67.8)	1.1	(68.9)
Other cash (receipts) payments	4.1	(0.2)	4.3
Net cash provided by operating activities	$464.5	$457.5	$7.0

(1) Excludes $3.2 million and $3.9 million included in investing activities for the six months ended June 30, 2017 and 2016 related to distributions from GCF and the T2 Joint Ventures that exceeded cumulative equity earnings.
(2) Net of capitalized interest paid of $4.1 million and $6.3 million included in investing activities for the six months ended June 30, 2017 and 2016.

Higher commodity prices were the primary contributor to increased cash collections and payments for product purchases in 2017 compared to 2016. Cash received from derivative settlements was lower as commodity price spreads between the prices paid to counterparties and the fixed prices we received on those derivative contracts were lower in 2017 in comparison to 2016. Interest payments are lower this year largely due to lower average outstanding debt balances, offset by the timing of payments of interest on two new series of notes we issued in 2016. Cash payments for general and administrative expenses and operating expenses were higher, primarily due to increases in compensation and benefits, contractor and other professional services, coupled with higher utilities and higher maintenance. The tax refund from net operating loss carry back was received in the second quarter of 2017, contributing to the change in cash tax paid net of refunds. Other cash payments in 2017 were higher mainly due to transaction expenses associated with the Permian Acquisition in 2017.

Cash Flows from Investing Activities

Six Months Ended June 30, 2017	2016	2017 vs. 2016
(In millions)		
$(1,108.6)	$(305.2)	$(803.4)

Cash used in investing activities increased in 2017 compared to 2016, primarily due to the $570.8 million outlay for the cash portion of the Permian Acquisition consideration. Capital expenditures increased $219.9 million during 2017 reflecting the spending for major growth projects during 2017 and the acquisition of the Flag City Plant.

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Cash Flows from Financing Activities

	Six Months Ended June 30,	
	2017	2016
Source of Financing Activities, net	(In millions)	
Debt, including financing costs	$(462.6)	$(918.6)
Equity offerings, net of financing costs	1,558.5	1,131.0
Dividends and distributions	(408.6)	(346.4)
Other	(18.0)	12.4
Net cash provided by (used in) financing activities	$669.3	$(121.6)

In 2017, we realized a net source of cash from financing activities, primarily due to equity offerings, offset by a net reduction of debt outstanding and payment of dividends and distributions. We issued 9,200,000 shares of common stock in January 2017 and 17,000,000 shares of common stock in June 2017 through public offerings in addition to common stock offerings through our December 2016 equity distribution agreement. A portion of the proceeds from the equity issuances was used to repay outstanding borrowings under the TRP Revolver and to redeem TRP's 6 % Senior Notes.

In 2016, we incurred a net use of cash from financing activities, primarily due to a net reduction of debt outstanding and payment of dividends and distributions, partially offset by proceeds from our Series A Preferred and Warrants offering. With the proceeds from equity issuances we repurchased a portion of the Partnership's senior notes through open market repurchases generally at a discount to par value and repaid a portion of our senior secured credit facilities.

Common Dividends

The following table details the dividends on common stock declared and/or paid by us for the six months ended June 30, 2017:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock (per share

					amounts)
June 30, 2017	August 15, 2017	$ 198.6	$ 196.2	$ 2.4	$ 0.91000
March 31, 2017	May 16, 2017	182.8	180.3	2.5	0.91000
December 31, 2016	February 15, 2017	178.3	176.5	1.8	0.91000

(1) Represents accrued dividends on restricted stock and restricted stock units that are payable upon vesting.
Preferred Dividends

Our Series A Preferred has a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. We may elect to pay dividends in kind (“PIK”) for any quarter through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of warrants would be issued. We have not made an election to PIK through June 30, 2017.

Cash dividends of $45.8 million were paid to holders of the Series A Preferred during the six months ended June 30, 2017. As of June 30, 2017, cash dividends accrued for our Series A Preferred were $22.9 million, which will be paid on August 14, 2017.

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as expansion expenditures including business acquisitions and maintenance expenditures. Expansion capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues, and fund acquisitions of businesses or assets. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

	Six Months Ended June 30,	
	2017	2016
	(In millions)	
Capital expenditures:		
Consideration for business acquisition	$987.1	$—
Contingent consideration (1)	(416.3)	—
Business acquisition, net of cash acquired	570.8	—
Expansion	560.0	256.6
Maintenance	49.1	35.2
Gross capital expenditures	609.1	291.8
Transfers from materials and supplies inventory to property, plant and equipment	(1.5)	(0.9)
Decrease in capital project payables and accruals	(80.0)	16.8
Cash outlays for capital projects	527.6	307.7
Total	$1,098.4	$307.7

(1) See Note 4 – Acquisitions and Divestitures of the "Consolidated Financial Statements." Represents the preliminary estimated fair value of contingent consideration at the acquisition date.

We currently estimate that we will invest at least $1,375 million in net growth capital expenditures (exclusive of outlays for business acquisitions) for announced projects in 2017. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time that we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. Our expansion capital expenditures increased for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, primarily due to the spending related to the Joyce Plant, the Johnson Plant, the Wildcat Plant, related Midland Basin and Delaware Basin gas and crude gathering infrastructure expansions, Grand Prix NGL pipeline and the Channelview Splitter, as well as the acquisition of Flag City Plant. The increase is partially offset by the impact of the substantial completion of the CBF Train 5 construction project in the second quarter of 2016. We continue to expect that 2017 net maintenance capital expenditures will be approximately $110.0 million. Our maintenance capital expenditures increased for 2017 as compared to 2016, primarily due to higher numbers of compressors reaching the end of their maintenance cycles in the six months ended June 30, 2017 versus the six months ended June 30, 2016 and increased well connects.

Off-Balance Sheet Arrangements

As of June 30, 2017, there were $38.4 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes, NGL equity volumes and condensate equity volumes and future commodity purchases and sales through 2019. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

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

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of June 30, 2017, we have hedged the commodity price associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements and (ii) future commodity purchases and sales in our Logistics and Marketing segment by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors), futures or other derivative instruments as market conditions permit.

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

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

We also enter into commodity price hedging transactions using futures contracts on futures exchanges. Exchange traded futures are subject to exchange margin requirements, so we may have to increase our cash deposit due to a rise in natural gas and NGL prices. Unlike bilateral hedges, we are not subject to counterparty credit risks when using futures on futures exchanges.

Our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $5.4 million and $17.6 million, during the three months ended June 30, 2017 and 2016, and $(1.3) million and $38.9 million, during the six months ended June 30, 2017 and 2016, as a result of transactions accounted for as derivatives. We account for derivatives designated as hedges that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income until the underlying hedged transactions settle. We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

Our risk management position has moved from a net liability position of $53.3 million at December 31, 2016 to a net asset position of $38.0 million at June 30, 2017. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position.

As of June 30, 2017, we had the following derivative instruments that will settle during the years shown below:

Natural GAS

Instrument		Price					
Type	Index	$/MMBtu		MMBtu/d			Fair Value (In millions)
				2017	2018	2019	
Gathering & Processing							
Swap	IF-Waha	2.87		103,600	-	-	$ 2.5
Swap	IF-Waha	2.68		-	73,600	-	3.5
Swap	IF-Waha	2.77		-	-	45,383	4.8
				103,600	73,600	45,383	
Swap	IF-PB	2.64		25,900	-	-	(0.3)
Swap	IF-PB	2.50		-	25,900	-	0.2
Swap	IF-PB	2.42		-	-	15,000	(0.0)
				25,900	25,900	15,000	
Swap	IF-PEPL	2.6835		16,000	-	-	(0.1)
Swap	IF-PEPL	2.6835		-	16,000	-	0.7
Swap	IF-PEPL	2.6835		-	-	16,000	1.3
				16,000	16,000	16,000	
Swap	NG-NYMEX	3.99		9,783	-	-	1.6
		Put Price	Call Price				
Collar	IF-Waha	3.00	3.67	7,500	-	-	0.5
Collar	IF-Waha	3.25	4.20	-	1,849	-	0.3
				7,500	1,849	-	
		Put Price	Call Price				
Collar	IF-PB	2.80	3.50	15,400	-	-	0.6
Collar	IF-PB	3.00	3.65	-	7,637	-	1.5

			15,400	7,637	-	
Basis Swap	EP-PERMIAN	(0.1444)	4,891	-	-	0.2
Basis Swap	PEPL	(0.3308)	4,891	-	-	0.0
Gathering & Processing total			187,965	124,986	76,383	$ 17.3
Other (1)						
Swap	NG-NYMEX	(3.1680)	(455)	(173)	(247)	$ (0.0)
Basis Swap	Various	Various	111,957	3,226	-	(0.7)
Future	Various	3.2640	-	1,103	-	(0.0)
Other total			111,502	4,156	(247)	$ (0.7)
						$ 16.6

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(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.

NGLs

Instrument		Price					
Type	Index	$/gal		Bbl/d			Fair Value (In millions)
				2017	2018	2019	
Gathering & Processing							
Swap	C2-OPIS-MB	0.2781		4,830	-	-	$ 0.9
Swap	C2-OPIS-MB	0.2794		-	2,918	-	(0.1)
Swap	C2-OPIS-MB	0.2917		-	-	2,260	(0.8)
Total				4,830	2,918	2,260	
Swap	C3-OPIS-MB	0.6456		7,802	-	-	1.8
Swap	C3-OPIS-MB	0.5530		-	2,650	-	(0.4)
Swap	C3-OPIS-MB	0.5530		-	-	2,650	0.4
Total				7,802	2,650	2,650	
Swap	IC4-OPIS-MB	0.8065		740	-	-	0.3
Swap	IC4-OPIS-MB	0.7487		-	230	-	0.2
Swap	IC4-OPIS-MB	0.7200		-	-	110	0.1
Total				740	230	110	
Swap	NC4-OPIS-MB	0.7935		1,800	-	-	0.7
Swap	NC4-OPIS-MB	0.7388		-	600	-	0.6
Swap	NC4-OPIS-MB	0.7050		-	-	300	0.2
Total				1,800	600	300	
Swap	C5-OPIS-MB	1.1056		1,510	-	-	0.9
Swap	C5-OPIS-MB	1.0385		-	810	-	(0.1)
Swap	C5-OPIS-MB	1.0825		-	-	569	0.4
Total				1,510	810	569	
		Put Price	Call Price				
Collar	C2-OPIS-MB	0.240	0.290	410	-	-	0.0
Total				410	-	-	
		Put Price	Call Price				
Collar	C3-OPIS-MB	0.570	0.68625	380	-	-	0.0
Collar	C3-OPIS-MB	0.530	0.65000	-	900	-	0.1
Total				380	900	-	

		Put Price	Call Price					
Collar	IC4-OPIS-MB			-	-	-		0.0
Collar	IC4-OPIS-MB	0.650	0.840	-	110	-		0.0
Collar	IC4-OPIS-MB	0.640	0.800	-	-	110		0.1
Total				-	110	110		

		Put Price	Call Price					
Collar	NC4-OPIS-MB			-	-	-		0.0
Collar	NC4-OPIS-MB	0.650	0.800	-	300	-		0.1
Collar	NC4-OPIS-MB	0.640	0.760	-	-	300		0.1
Total				-	300	300		

		Put Price	Call Price					
Collar	C5-OPIS-MB	1.210	1.415	130	-	-		0.2
Collar	C5-OPIS-MB	1.230	1.385	-	32	-		0.1
Total				130	32	-		
Gathering & Processing total				17,602	8,550	6,299	$	5.8
Other (1)(2)								
Future	C2-OPIS-MB	0.2741		5,707	-	-	$	0.7
Future	C2-OPIS-MB	0.3007		-	1,534	-		0.4
Total				5,707	1,534	-		
Future	C3-OPIS-MB	0.6520		9,321	-	-		2.2

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Future	C3-OPIS-MB	0.6257	-	4,384	-	0.3
Total			9,321	4,384	-	
Future	IC4-OPIS-MB	0.7728	679	-	-	0.1
Future	IC4-OPIS-MB	0.7825	-	55	-	0.0
Total			679	55	-	
Future	NC4-OPIS-MB	0.7652	2,690	-	-	0.4
Future	NC4-OPIS-MB	0.8027	-	1,616	-	1.5
Total			2,690	1,616	-	
Future	C5-OPIS-MB	0.9846	190	-	-	(0.1)
Future	C5-OPIS-MB	1.0725	-	27	-	0.0
Total			190	27	-	
	Put Price					
Option	C2-OPIS-MB	0.2694	1,087	-	-	0.3
Option	C2-OPIS-MB	0.2963	-	1,644	-	1.3
Total			1,087	1,644	-	
Other total			19,674	9,260	-	$7.1
						$12.9

(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.
(2) The "Future" line items are comprised of futures transactions entered into on both the Intercontinental Exchange ("ICE") and Chicago Mercantile Exchange ("CME").

CONDENSATE

Instrument Type	Index	Price $/Bbl		Bbl/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing							
Swap	WTI-NYMEX	54.54		2,690	-	-	$ 3.8
Swap	WTI-NYMEX	48.79		-	2,190	-	0.4
Swap	WTI-NYMEX	51.19		-	-	1,063	0.7
				2,690	2,190	1,063	
		Put Price	Call Price				
Collar	WTI-NYMEX	54.04	64.09	1,380	-	-	2.1

Collar	WTI-NYMEX	49.76	58.50	-	691	-		1.1
Collar	WTI-NYMEX	48.00	56.25	-	-	590		0.4
				1,380	691	590		
Total				4,070	2,881	1,653		
							$	8.5

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

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity contract, the valuations are classified as Level 3 within the fair value hierarchy. See Note 17 - Fair Value Measurements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRC Revolver, the TRP Revolver and the Securitization Facility. As of June 30, 2017, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Revolver, TRP Revolver and the Securitization Facility will also increase. As of June 30, 2017, the Partnership had $250.0 million in outstanding variable rate borrowings under the TRP Revolver and Securitization Facility, and we had outstanding variable rate borrowings of $435.0 million under the TRC Revolver. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact the Partnership’s annual interest expense by $2.5 million and our consolidated annual interest expense by $6.9 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are margined daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with all our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $15.0 million as of June 30, 2017. The range of losses attributable to our individual counterparties would be between $0.4 million and $16.7 million, depending on the counterparty in default.

Customer Credit Risk

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

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable as of June 30, 2017, our operating income would decrease by $5.5 million in the year of the assessment.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered in this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were not effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure because of the material weakness in our internal control over financial reporting as described below.

Previously Identified Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our Annual Report, we did not maintain effective controls over the preparation and review of income tax provisions for interim periods. Specifically, our controls were not designed to detect material clerical errors, as well as identify and address unusual and infrequently occurring circumstances requiring special consideration under accounting standards applicable to the determination of income tax expense for interim periods.

Remediation Status

In response to the material weakness disclosed in our Annual Report, we developed a plan for remediation that consists of the following elements:

- Performing an independent detailed review and re-performance of key elements of the interim tax provision calculation and entries to provide additional assurance that clerical errors are detected, and that detailed reviews already required under our controls and procedures are performed timely and effectively.
- Incorporating into our process a formal interim tax provision checklist designed to ensure that we identify and appropriately address unusual and infrequently occurring circumstances requiring special consideration under GAAP applicable to interim income taxes.
- Conducting formal reviews with financial and tax executive management to provide enhanced transparency and to facilitate an assessment of appropriateness of the estimated annual effective tax rate utilized in the preparation of interim income tax provisions.

We are in the process of testing and evaluating the operational effectiveness of the revised controls and procedures in conjunction with the preparation of our interim financial statements during 2017.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, during our most recent fiscal quarter.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 18 – Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Part I—Item 1A Risk Factors” of our Annual Report. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

Recent Sales of Unregistered Securities.

None.

Repurchase of Equity by Targa Resources Corp. or Affiliated Purchasers.

Period	Total number of shares withheld (1)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet to be purchased under the plan
May 1, 2017 - May 31, 2017	517	$ 55.44	—	—
June 1, 2017 - June 30, 2017	35,351	$ 44.93	—	—

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

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Certificate of Designations of Series A Preferred Stock of Targa Resources Corp., filed with the Secretary of State of the State of Delaware on March 16, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
3.3	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.2 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.4	First Amendment to the Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed January 15, 2016 (File No. 001-34991)).
3.5	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.6	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.7	Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, effective December 1, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 21, 2016 (File No. 001-33303)).
3.8	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1+	Amended and Restated Targa Resources Corp. 2010 Stock Incentive Plan, as amended and restated effective May 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed May 23, 2017 (File No. 001-34991)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	

	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*Filed herewith
**Furnished herewith
+Management contract or compensatory plan or arrangement

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SIGNATURES

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

		Targa Resources Corp. (Registrant)
Date: August 3, 2017	By:	/s/ Matthew J. Meloy Matthew J. Meloy Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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