TC PIPELINES LP
Form 10-Q
November 09, 2018
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2018

or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 001-35358

TC PipeLines, LP

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**52-2135448** (I.R.S. Employer Identification Number)
700 Louisiana Street, Suite 700 **Houston, Texas** (Address of principle executive offices)	**77002-2761** (Zip code)

877-290-2772

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o
Emerging growth company o	

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No x

As of November 9, 2018, there were 71,306,396 of the registrant s common units outstanding.

TC PIPELINES, LP

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All amounts are stated in United States dollars unless otherwise indicated.

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DEFINITIONS

The abbreviations, acronyms, and industry terminology used in this quarterly report are defined as follows:

2013 Term Loan Facility	TC PipeLines, LP s term loan credit facility under a term loan agreement as amended, dated September 29, 2017
2015 GTN Acquisition	Partnership s acquisition of the remaining 30 percent interest in GTN on April 1, 2015
2015 Term Loan Facility	TC PipeLines, LP s term loan credit facility under a term loan agreement as amended, dated September 29, 2017
2017 Acquisition	Partnership s acquisition of an additional 11.81 percent interest in PNGTS and 49.34 percent in Iroquois on June 1, 2017
2017 Great Lakes Settlement	Stipulation and Agreement of Settlement for Great Lakes regarding its rates and terms and conditions of service approved by FERC on February 22, 2018
2017 Northern Border Settlement	Stipulation and Agreement of Settlement for Northern Border regarding its rates and terms and conditions of service approved by FERC on February 23, 2018
2017 Tax Act	H.R.1, originally known as the Tax Cuts and Jobs Act, enacted on December 22, 2017
2018 FERC Actions	FERC s March 15, 2018 issuance of (1) a revised Policy Statement to address the treatment of income taxes for ratemaking purposes for master limited partnerships (MLPs), (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact of the federal income tax rate reduction and the revised Policy Statement could have on pipelines revenue requirements, and (3) a Notice of Inquiry (NOI) seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation; and FERC s July 18, 2018 issuance of (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing related to the revised Policy Statement and (2) a Final Rule adopting procedures from, and clarifying aspects of, the NOPR
2018 GTN Settlement	Stipulation and Agreement of Settlement for GTN regarding its rates and terms and conditions of service filed for approval with FERC on October 16, 2018
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM program	At-the-market equity issuance program
Bison	Bison Pipeline LLC
Class B Distribution	Annual distribution to TransCanada based on 30 percent of GTN s annual distributions as follows: (i) 100 percent of distributions above $20 million through March 31, 2020; and (ii) 25 percent of distributions above $20 million thereafter
Class B Reduction	35 percent reduction applied to the estimated annual Class B Distribution beginning in 2018, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018. The Class B Reduction will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit
Consolidated Subsidiaries	GTN, Bison, North Baja, Tuscarora and PNGTS
C2C Contracts	PNGTS Continent-to-Coast Contracts with several shippers for a term of 15 years for approximately 82,000 Dth/day
DOT	U.S. Department of Transportation
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
General Partner	TC PipeLines GP, Inc.
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest LLC
IDRs	Incentive Distribution Rights
ILPs	Intermediate Limited Partnerships

Iroquois	Iroquois Gas Transmission System, L.P.

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LIBOR	London Interbank Offered Rate
MLPs	Master limited partnerships
NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
Our pipeline systems	Our ownership interests in GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, PNGTS and Iroquois
Partnership	TC PipeLines, LP including its subsidiaries, as applicable
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
PXP	Portland XPress Project
Term Loan Facilities	The 2013 Term Loan Facility and the 2015 Term Loan Facility, collectively
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP s senior facility under revolving credit agreement as amended and restated, dated September 29, 2017
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
VIEs	Variable Interest Entities

Unless the context clearly indicates otherwise, TC PipeLines, LP and its subsidiaries are collectively referred to in this quarterly report as we, us, our and the Partnership. We use our pipeline systems and our pipelines when referring to the Partnership s ownership interests in Gas Transmission Northwest LLC (GTN), Northern Border Pipeline Company (Northern Border), Bison Pipeline LLC (Bison), Great Lakes Gas Transmission Limited Partnership (Great Lakes), North Baja Pipeline, LLC (North Baja), Tuscarora Gas Transmission Company (Tuscarora), Portland Natural Gas Transmission System (PNGTS) and Iroquois Gas Transmission System, LP (Iroquois).

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PART I

FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This report includes certain forward-looking statements. Forward-looking statements are identified by words and phrases such as: anticipate, assume, estimate, expect, project, intend, plan, believe, forecast, should, predict, could, will, may, and other terms ar meaning. The absence of these words, however, does not mean that the statements are not forward-looking. These statements are based on management s beliefs and assumptions and on currently available information and include, but are not limited to, statements regarding anticipated financial performance, future capital expenditures, liquidity, dropdown opportunities, market or competitive conditions, regulations, organic or strategic growth opportunities, contract renewals and ability to market open capacity, business prospects, outcome of regulatory proceedings and cash distributions to unitholders.

Forward-looking statements involve risks and uncertainties that may cause actual results to differ materially from the results predicted. Factors that could cause actual results and our financial condition to differ materially from those contemplated in forward-looking statements include, but are not limited to:

- the ability of our pipeline systems to sell available capacity on favorable terms and renew expiring contracts which are affected by, among other factors:

- demand for natural gas;
- changes in relative cost structures and production levels of natural gas producing basins;
- natural gas prices and regional differences;
- weather conditions;
- availability and location of natural gas supplies in Canada and the United States (U.S.) in relation to our pipeline systems;
- competition from other pipeline systems;
- natural gas storage levels; and
- rates and terms of service;

- the performance by the shippers of their contractual obligations on our pipeline systems;

- the outcome and frequency of rate proceedings or settlement negotiations on our pipeline systems;
- the impact of the 2017 Tax Act and the 2018 FERC Actions on our future operating performance;
- other potential changes in taxation of master limited partnerships (MLPs) by state or federal governments;
- increases in operational or compliance costs resulting from changes in laws and governmental regulations affecting our pipeline systems, particularly regulations issued by the Federal Energy Regulatory Commission (FERC), the U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT);
- the impact of downward changes in oil and natural gas prices, including the effects on the creditworthiness of our shippers;
- our ongoing ability to grow distributions through acquisitions, accretive expansions or other growth opportunities, including the timing, terms and closure of future potential acquisitions;
- potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner), TransCanada Corporation (TransCanada) and us;
- the impact of any impairment charges;
- the ability to maintain secure operation of our information technology including management of cybersecurity threats, acts of terrorism and related distractions;
- the expected impact of future accounting changes, commitments and contingent liabilities (if any);
- operating hazards, casualty losses and other matters beyond our control;
- the level of our indebtedness, including the indebtedness of our pipeline systems, and the availability of capital;
- unfavorable conditions in capital and credit markets, inflation and fluctuations in interest rates; and
- the overall increase in the allocated management and operational expenses on our pipeline systems for functions performed by TransCanada.

These are not the only factors that could cause actual results to differ materially from those expressed or implied in any forward-looking statement. Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. These and other risks are described in greater detail in Part II, Item 1A Risk Factors of this report and in Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2017 as filed with the SEC on February 26, 2018. All forward-looking

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statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. All forward-looking statements are made only as of the date made and except as required by applicable law, we undertake no obligation to update any forward-looking statements to reflect new information, subsequent events or other changes.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

TC PIPELINES, LP

CONSOLIDATED STATEMENTS OF INCOME

(unaudited) **(millions of dollars, except per common unit amounts)**	**Three months ended September 30,** **2018**	**2017**	**Nine months ended September 30,** **2018**	**2017**
Transmission revenues, net *(Notes 4 and 6)*	**103**	100	**328**	313
Equity earnings *(Note 5)*	**34**	27	**129**	87
Operation and maintenance expenses	**(15)**	(16)	**(48)**	(47)
Property taxes	**(7)**	(7)	**(21)**	(21)
General and administrative	**(2)**	(1)	**(4)**	(6)
Depreciation	**(25)**	(25)	**(73)**	(73)
Financial charges and other *(Note 15)*	**(23)**	(23)	**(69)**	(59)
Net income before taxes	**65**	55	**242**	194
Income taxes *(Note 18)*			**(1)**	(1)
Net income	**65**	55	**241**	193
Net income attributable to non-controlling interests	**3**	1	**10**	7
Net income attributable to controlling interests	**62**	54	**231**	186
Net income attributable to controlling interest allocation ***(Note 9)***				
Common units	**57**	42	**222**	164
General Partner	**1**	4	**5**	12
TransCanada and its subsidiaries	**4**	8	**4**	10
	62	54	**231**	186
Net income per common unit ***(Note 9)*** basic and diluted	**$ 0.79**	$ 0.61	**$ 3.11**	$ 2.38
Weighted average common units outstanding basic and diluted *(millions)*	**71.3**	69.4	**71.3**	68.9
Common units outstanding, end of period *(millions)*	**71.3**	69.6	**71.3**	69.6

The accompanying notes are an integral part of these consolidated financial statements.

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TC PIPELINES, LP CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited) (millions of dollars)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Net income	**65**	55	**241**	193
Other comprehensive income				
Change in fair value of cash flow hedges *(Note 13)*	**2**		**8**	1
Amortization of realized loss on derivative financial instruments *(Note 13)*			**2**	1
Reclassification to net income of gains and losses on cash flow hedges *(Note 13)*	**1**	1	**4**	
Comprehensive income	**68**	56	**255**	195
Comprehensive income attributable to non-controlling interests	**2**	1	**11**	7
Comprehensive income attributable to controlling interests	**66**	55	**244**	188

The accompanying notes are an integral part of these consolidated financial statements.

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TC PIPELINES, LP

CONSOLIDATED BALANCE SHEETS

(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	**48**	33
Accounts receivable and other *(Note 14)*	**39**	42
Inventories	**7**	8
Other	**8**	7
	102	90
Equity investments *(Note 5)*	**1,196**	1,213
Property, plant and equipment (Net of $1,252 accumulated depreciation; 2017 - $1,181)	**2,075**	2,123
Goodwill	**130**	130
Other assets	**13**	3
	3,516	3,559
LIABILITIES AND PARTNERS EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**30**	31
Provision for revenue sharing *(Note 4)*	**9**	
Accounts payable to affiliates *(Note 12)*	**5**	5
Distribution payable		1
Accrued interest	**20**	12
Current portion of long-term debt *(Note 7)*	**36**	51
	100	100
Long-term debt, net *(Note 7)*	**2,211**	2,352
Deferred state income taxes *(Note 18)*	**10**	10
Other liabilities	**29**	29
	2,350	2,491
Partners Equity		
Common units	**921**	824
Class B units *(Note 8)*	**99**	110
General partner	**23**	24
Accumulated other comprehensive income (AOCI)	**18**	5
Controlling interests	**1,061**	963
Non-controlling interests	**105**	105
	1,166	1,068
	3,516	3,559

Contingencies *(Note 16)*

Variable Interest Entities *(Note 17)*

Subsequent Events *(Note 19)*

The accompanying notes are an integral part of these consolidated financial statements.

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TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CASH FLOWS

(unaudited) (millions of dollars)	Nine months ended September 30, 2018	2017
Cash Generated from Operations		
Net income	**241**	193
Depreciation	**73**	73
Amortization of debt issue costs reported as interest expense	**1**	1
Amortization of realized loss on derivative instrument *(Note 13)*	**2**	1
Equity earnings from equity investments *(Note 5)*	**(129)**	(87)
Distributions received from operating activities of equity investments *(Note 5)*	**142**	106
Change in other long-term liabilities	**(1)**	
Change in operating working capital *(Note 11)*	**25**	24
	354	311
Investing Activities		
Investment in Northern Border		(83)
Investment in Great Lakes	**(4)**	(4)
Acquisition of a 49.34 percent in Iroquois and an additional 11.81 percent in PNGTS		(646)
Distribution received from Iroquois as return of investment *(Note 5)*	**8**	3
Capital expenditures	**(28)**	(26)
	(24)	(756)
Financing Activities		
Distributions paid *(Note 10)*	**(171)**	(210)
Distributions paid to Class B units *(Note 8)*	**(15)**	(22)
Distributions paid to non-controlling interests	**(11)**	(5)
Distributions paid to former parent of PNGTS		(1)
Common unit issuance, net *(Note 8)*	**40**	126
Long-term debt issued, net *(Note 7)*	**159**	732
Long-term debt repaid *(Note 7)*	**(316)**	(164)
Debt issuance costs	**(1)**	(2)
	(315)	454
Increase in cash and cash equivalents	**15**	9
Cash and cash equivalents, beginning of period	**33**	64
Cash and cash equivalents, end of period	**48**	73

The accompanying notes are an integral part of these consolidated financial statements.

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TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS EQUITY

(unaudited)	Limited Partners Common Units millions of units	Limited Partners Common Units millions of dollars	Limited Partners Class B Units millions of units	Limited Partners Class B Units millions of dollars	General Partner millions of dollars	Accumulated Other Comprehensive Income (a) millions of dollars	Non-Controlling Interest millions of dollars	Total Equity millions of dollars
Partners Equity at December 31, 2017	70.6	824	1.9	110	24	5	105	1,068
Net income		222		4	5		10	241
Other comprehensive income						13	1	14
ATM equity issuances, net *(Note 8)*	0.7	39			1			40
Distributions		(164)		(15)	(7)		(11)	(197)
Partners Equity at September 30, 2018	**71.3**	**921**	**1.9**	**99**	**23**	**18**	**105**	**1,166**

(a) Gains (Losses) related to cash flow hedges reported in Accumulated Other Comprehensive Income and expected to be reclassified to Net income in the next 12 months are estimated to be $4 million. These estimates assume constant interest rates over time; however, the amounts reclassified will vary based on actual value of interest rates at the date of settlement.

The accompanying notes are an integral part of these consolidated financial statements.

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TC PIPELINES, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiaries are collectively referred to herein as the Partnership. The Partnership was formed by TransCanada PipeLines Limited, a wholly owned subsidiary of TransCanada Corporation (TransCanada Corporation together with its subsidiaries collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America.

The Partnership owns its pipeline assets through three intermediate limited partnerships (ILPs), TC GL Intermediate Limited Partnership, TC PipeLines Intermediate Limited Partnership and TC Tuscarora Intermediate Limited Partnership.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying financial statements and related notes have been prepared in accordance with United States generally accepted accounting principles (GAAP) and amounts are stated in U.S. dollars. The results of operations for the three and nine months ended September 30, 2018 and 2017 are not necessarily indicative of the results that may be expected over the full fiscal year.

The accompanying financial statements should be read in conjunction with the audited financial statements and notes thereto for the year ended December 31, 2017 included in our Annual Report on Form 10-K. That report contains a more comprehensive summary of the Partnership s significant accounting policies. In the opinion of management, the accompanying financial statements contain all of the appropriate adjustments, all of which are normally recurring adjustments unless otherwise noted, and considered necessary to present fairly the financial position of the Partnership, the results of operations and cash flows for the respective periods. Our significant accounting policies are consistent with those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017, except as described in Note 3, Accounting Pronouncements.

Basis of Presentation

The Partnership consolidates its interests in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. The Partnership uses the equity method of accounting for its investments in entities over which it is able to exercise significant influence.

Acquisitions by the Partnership from TransCanada are considered common control transactions. When businesses are acquired from TransCanada that will be consolidated by the Partnership, the historical financial statements are required to be recast, except net income per common unit, to include the acquired entities for all periods presented.

When the Partnership acquires an asset or an investment from TransCanada, which will be accounted for by the equity method, the financial information is not required to be recast and the transaction is accounted for prospectively from the date of the acquisition.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates.

NOTE 3 ACCOUNTING PRONOUNCEMENTS

Changes in Accounting Policies effective January 1, 2018

Revenue from contracts with customers

In 2014, the Financial Accounting Standards Board (FASB) issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Partnership s performance obligations. The total consideration to which the Partnership expects to be entitled can include fixed and variable amounts. The Partnership has variable revenue that is subject to factors outside the Partnership s influence, such as market volatility, actions of third parties and weather conditions. The Partnership considers this variable revenue to be constrained as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and the related cash flows. Effective January 1, 2018, the new guidance was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 6 - Revenues, for further information related to the impact of adopting the new guidance and the Partnership s updated accounting policies related to revenue recognition from contracts with customers.

Hedge Accounting

In August 2017, the FASB issued new guidance on hedge accounting, making more financial and nonfinancial hedging strategies eligible for hedge accounting. The new guidance amends the presentation requirements relating to the change in fair value of a derivative and additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019 with early adoption permitted. The Partnership has elected to prospectively apply this guidance effective January 1, 2018. The application of this guidance did not have a material impact on its consolidated financial statements.

Future accounting changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for the arrangement to qualify as a lease, the lessor is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

In January 2018, the FASB issued new guidance on accounting for land easements which provides an optional transition practical expedient to not evaluate existing or expired land easements not accounted for as leases prior to entity s adoption of the new guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Partnership intends to apply this practical expedient upon transition to the new standard.

The new guidance is effective on January 1, 2019, with early adoption permitted. The Partnership expects to adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. In July 2018, the FASB issued a transition option for entities to opt to not apply the new guidance, including disclosure requirements to the comparative periods they present in their financial statements in the year of adoption. The Partnership intends to apply this transition option upon adoption of the new standard which will allow the Partnership to not update financial information and disclosures required under the new standard for dates and periods before January 1, 2019.

The Partnership intends to elect the package of practical expedients which permits entities not to reassess under the new standard prior conclusions about lease identification, lease classification and initial direct costs. The Partnership continues to monitor and analyze other optional practical expedients as well as additional guidance and clarifications provided by the FASB.

The Partnership has developed a preliminary inventory of existing lease agreements and has substantially completed its analysis on these leases but continues to evaluate the financial impact on its consolidated financial statements. The Partnership has also selected a system solution and is in the testing stage of implementation. The Partnership continues to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and to analyze new contracts that may contain leases.

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Goodwill Impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit s carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted. The Partnership is currently evaluating the timing and impact of the adoption of this guidance.

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Fair Value Measurement

In August 2018, the FASB issued new guidance that relating to certain disclosure requirements for the fair value measurements as part of its disclosure framework project. This new guidance is effective January 1, 2020, however, early adoption is permitted. Entities that are making the election to early adopt are permitted to early adopt the eliminated or modified disclosure requirements and delay the adoption of the new disclosure requirements until their effective date. The Partnership is currently evaluating the impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

NOTE 4 REGULATORY

In December 2016, FERC issued a Notice of Inquiry (NOI) Regarding the Commission s Policy for Recovery of Income Tax Costs (Docket No. PL17-1-000) requesting initial comments regarding how to address any double recovery resulting from FERC s current income tax allowance and rate of return policies that had been in effect since 2005.

Docket No. PL17-1-000 is a direct response to *United Airlines, Inc., et al. v. FERC (United)*, a decision issued by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016 in which the D.C. Circuit directed FERC to explain how a pass-through entity such as an MLP receiving a tax allowance and a return on equity derived from the discounted cash flow (DCF) methodology did not result in double recovery of taxes.

On December 22, 2017, the President of the United States signed into law H.R.1, originally known as the Tax Cuts and Jobs Act (the 2017 Tax Act). This legislation provides for major changes to U.S. corporate federal tax law including a reduction of the federal corporate income tax rate. We are a non-taxable limited partnership for federal income tax purposes, and federal income taxes owed as a result of our earnings are the responsibility of our partners, therefore no amounts have been recorded in the Partnership s financial statements with respect to federal income taxes as a result of the 2017 Tax Act.

On March 15, 2018, FERC issued (1) a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) to address the treatment of income taxes for ratemaking purposes for MLPs, (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact of the federal income tax rate reduction and the Revised Policy Statement could have on a pipeline s Return on Equity (ROE) assuming a single-issue adjustment to a pipeline s rates, and (3) an NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes (ADIT) and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement (Order on Rehearing) dismissing rehearing requests related to the Revised Policy Statement and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR (collectively, the 2018 FERC Actions). The Final Rule became effective on September 13, 2018, and is subject to requests for further rehearing and clarification. Each is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates

The Revised Policy Statement changes FERC s long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

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On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regard to ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity s income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as the refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on Tax Law Changes for Interstate Natural Gas Companies

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantifies the isolated rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. Pipelines filing the one-time report will have four options:

- Option 1: make a limited Natural Gas Act (NGA) Section 4 filing to reduce its rates by the reduction in its cost of service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline s FERC Form 501-G shows the pipeline s estimated ROE as being 12 percent or less. Under the Final Rule and notwithstanding the Revised Policy Statement, a pipeline organized as an MLP is not required to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance, along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline s rate base used for rate-making purposes;

- Option 2: commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. If the pipeline commits to file either by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date;

- Option 3: file a statement explaining its rationale for why it does not believe the pipeline s rates must change; and

- Option 4: take no other action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates

In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, is required by FERC related to the ADIT that were reserved in anticipation of being paid to the Internal Revenue Service (IRS), but which no longer accurately reflect the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated rates or earnings.

As noted above, FERC s Order on Rehearing provided guidance with regard to ADIT for MLP pipelines, finding that if an MLP pipeline s income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

Filings required by the Final Rule

On October 16, 2018, GTN filed a rate settlement with FERC to address the changes proposed by the 2018 FERC Actions within its rates via an amendment to its prior settlement in 2015 (2018 GTN Settlement). The 2018 GTN Settlement will decrease GTN s existing maximum transportation rates by 10 percent effective January 1, 2019 until December 31, 2019. The existing maximum rates will decrease by an additional 6.6 percent for the period January 1, 2020 through December 31, 2021. GTN is required to have new rates in effect on January 1, 2022. These reductions will replace the eight percent rate reduction in GTN s reservation rates in 2020 agreed upon as part of GTN s last settlement in 2015. Furthermore, GTN and its customers have agreed upon a moratorium on further rate changes prior to January 1, 2022, providing a greater degree of regulatory certainty for GTN going forward. These new rates will reflect an elimination of tax allowance previously recovered in rates along with ADIT for rate-making purposes. The uncontested settlement, subject to approval by the FERC, will relieve GTN of its obligation to file a Form 501-G.

As part of the 2018 GTN Settlement, GTN has also agreed to issue a refund of approximately $10 million allocated amongst firm customers from January 1, 2018 to October 31, 2018 (2018 GTN Rate Refund). As a result of this, at September 30, 2018, the Partnership established a $9 million provision for this revenue sharing as an offset against revenue in the income statement and recognized the corresponding refund liability classified as a provision for revenue sharing in the balance sheet.

On October 11, 2018, North Baja elected to make a limited NGA Section 4 filing to reduce its maximum recourse rates by approximately 11 percent, which is the percentage reduction in the cost of service shown in North Baja s concurrent FERC Form No. 501-G (Option 1). The 11 percent reduction is not expected to have a material impact in North Baja s results as a significant portion of its contracts are negotiated rate arrangements.

On October 12, 2018, Iroquois requested a waiver of its requirement to file a Form 501-G from FERC based on its existing moratorium precluding rate changes prior to September 2020.

PNGTS and Bison filed their respective FERC Form No. 501-Gs on October 11, 2018 and November 8, 2018, respectively, along with an explanation why no rate change is needed (Option 3).

The Partnership s remaining assets, Northern Border, Great Lakes and Tuscarora, are scheduled to file their respective FERC Form No. 501-Gs by December 6, 2018. Thus, the Partnership anticipates finalizing its regulatory approach for all of the Partnership s assets by the end of the 2018.

Impairment Considerations

As noted under Note 2, the preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions, which cannot be known with certainty, that affect the reported amount of assets and liabilities at the date of the financial statements. Although we believe these estimates and assumptions are reasonable, actual results could differ.

We review property, plant and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate the possibility of impairment. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, an impairment test is not performed.

We continue to monitor developments following the Final Rule on the 2018 FERC Actions. We will incorporate results to date, future filings for the Partnership s assets and FERC s responses to others in the industry into our annual goodwill impairment test as well as our normal review of property, plant and equipment and equity investments for recoverability.

At September 30, 2018, the goodwill and the equity method goodwill balances related to Tuscarora and Great Lakes amounted to $82 million and $260 million (December 31, 2017- $82 million and $260 million), respectively. Additionally, the estimated fair values of Tuscarora and our investment in Great Lakes exceeded their carrying values by less than 10 percent in its most recent valuation. There is a risk that the goodwill balances related to Tuscarora and Great Lakes could be negatively impacted by the 2018 FERC Actions, once finalized or by other changes in management s estimates of fair value resulting in an impairment charge.

NOTE 5 EQUITY INVESTMENTS

The Partnership has equity interests in Northern Border, Great Lakes and Iroquois. The pipeline systems owned by these entities are regulated by FERC. The pipeline systems of Northern Border and Great Lakes are operated by subsidiaries of TransCanada. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Partnership uses the equity method of accounting for its interests in its equity

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investees. The Partnership s equity investments are held through our ILPs that are considered to be variable interest entities (VIEs) (Refer to Note 17).

	Ownership	Equity Earnings					
	Interest at	Three months		Nine months		Equity Investments	
(unaudited)	September 30,	ended September 30,		ended September 30,		September 30,	December 31,
(millions of dollars)	2018	2018	2017	2018	2017	2018	2017
Northern Border (a)	50%	**16**	16	**49**	50	**501**	512
Great Lakes	46.45%	**9**	2	**45**	24	**480**	479
Iroquois(b)	49.34%	**9**	9	**35**	13	**215**	222
		34	27	**129**	87	**1,196**	1,213

(a) Equity earnings from Northern Border is net of the 12-year amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the Partnership s acquisition of an additional 20 percent interest in April 2006.

(b) Equity earnings from Iroquois is net of the 29-year amortization of a $10 million purchase price discrepancy assumed by the Partnership from TransCanada at the time of the 2017 Acquisition.

Distributions from Equity Investments

Distributions received from equity investments for the nine months ended September 30, 2018 were $150 million, (2017 $109 million) of which $7.8 million (2017 - $2.6 million) was considered a return of capital and was included in investing activities in the Partnership s consolidated statement of cash flows. The return of capital was related to our investment in Iroquois (see further discussion below).

Northern Border

The Partnership did not have undistributed earnings from Northern Border for the three and nine months ended September 30, 2018 and 2017.

The summarized financial information provided to us by Northern Border is as follows:

(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
ASSETS		

Cash and cash equivalents	**17**	14
Other current assets	**34**	36
Property, plant and equipment, net	**1,048**	1,063
Other assets	**14**	14
	1,113	1,127
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	**43**	38
Deferred credits and other	**34**	31
Long-term debt, net (a)	**264**	264
Partners capital	**773**	795
Accumulated other comprehensive loss	**(1)**	(1)
	1,113	1,127

(a) No current maturities as of September 30, 2018 and December 31, 2017.

(unaudited) **(millions of dollars)**	**Three months ended September 30,**		**Nine months ended September 30,**	
	2018	**2017**	**2018**	**2017**
Transmission revenues	**72**	73	**212**	217
Operating expenses	**(19)**	(20)	**(57)**	(56)
Depreciation	**(15)**	(15)	**(45)**	(45)
Financial charges and other	**(5)**	(5)	**(12)**	(14)
Net income	**33**	33	**98**	102

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Great Lakes

The Partnership made an equity contribution to Great Lakes of $4 million in the first quarter of 2018. This amount represents the Partnership s 46.45 percent share of a $9 million cash call from Great Lakes to make a scheduled debt repayment.

The Partnership did not have undistributed earnings from Great Lakes for the three and nine months ended September 30, 2018 and 2017.

The summarized financial information provided to us by Great Lakes is as follows:

(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
ASSETS		
Current assets	**53**	107
Property, plant and equipment, net	**693**	701
	746	808
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	**18**	75
Net long-term debt, including current maturities (a)	**250**	259
Other long-term liabilities	**3**	1
Partners equity	**475**	473
	746	808

(a) Includes current maturities of $21 million as of September 30, 2018 (December 31, 2017 - $19 million).

(unaudited) (millions of dollars)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Transmission revenues	**49**	34	**183**	138
Operating expenses	**(17)**	(19)	**(50)**	(49)
Depreciation	**(8)**	(7)	**(24)**	(21)
Financial charges and other	**(5)**	(5)	**(13)**	(16)
Net income	**19**	3	**96**	52

Iroquois

On June 1, 2017, the Partnership, through its interest in TC PipeLines Intermediate Limited Partnership acquired a 49.34 percent interest in Iroquois. During the nine months ended September 30, 2018, the Partnership received distributions from Iroquois amounting to $42 million, which includes the Partnership s 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $7.8 million, respectively. The unrestricted cash does not represent a distribution of Iroquois cash from operations during the period and therefore it was reported as distributions received as return of investment in the Partnership s consolidated statement of cash flows.

Iroquois declared its third quarter 2018 distribution of $29 million on October 22, 2018, of which the Partnership received its 49.34 percent share of $14 million on November 1, 2018. The distribution includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $2.6 million. The Partnership did not have undistributed earnings from Iroquois for the three and nine months ended September 30, 2018 and 2017.

The summarized financial information provided to us by Iroquois for the period from the June 1, 2017 acquisition date through September 30, 2018 is as follows:

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(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
ASSETS		
Cash and cash equivalents	**91**	86
Other current assets	**34**	36
Property, plant and equipment, net	**582**	591
Other assets	**9**	8
	716	721
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	**23**	17
Net long-term debt, including current maturities (a)	**327**	329
Other non-current liabilities	**13**	9
Partners equity	**353**	366
	716	721

(a) Includes current maturities of $145 million as of September 30, 2018 (December 31, 2017 - $4 million).

(unaudited) (millions of dollars)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Four months ended September 30, 2017
Transmission revenues	**42**	43	**147**	57
Operating expenses	**(13)**	(13)	**(41)**	(18)
Depreciation	**(7)**	(7)	**(22)**	(9)
Financial charges and other	**(4)**	(4)	**(11)**	(5)
Net income	**18**	19	**73**	25

NOTE 6 REVENUES

In 2014, the FASB issued new guidance on revenue from contracts with customers. The Partnership adopted the new guidance on January 1, 2018 using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for all periods in 2018 reflect the application of the new guidance, while the reported results for all periods in 2017 were prepared under previous revenue recognition guidance which is referred to herein as legacy U.S. GAAP .

Disaggregation of Revenues

For the three and nine months ended September 30, 2018, virtually all of the Partnership s revenues were from capacity arrangements and transportation contracts with customers as discussed in more detail below.

Capacity Arrangements and Transportation Contracts

The Partnership s performance obligations in its contracts with customers consist primarily of capacity arrangements and natural gas transportation contracts.

The Partnership s revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas which are treated as a bundled performance obligation. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed. The Partnership has elected to utilize the practical expedient of recognizing revenue as invoiced.

The Partnership s pipeline systems are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management s best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained, as applicable, at the time a regulatory decision becomes final (See also the 2018 GTN Rate Refund discussion in Note 4). Revenues are invoiced and paid on a monthly basis. The Partnership s pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

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Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Partnership adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Partnership is not required to analyze completed contracts at the date of adoption. The adoption of the new guidance did not have a material impact on the Partnership s previously reported consolidated financial statements at December 31, 2017.

Pro-forma Financial Statements under Legacy U.S. GAAP

At September 30, 2018, had legacy U.S. GAAP been applied, there would be no change in the Partnership s reported balance sheet and income statement line items.

Contract Balances

(unaudited-millions of dollars)	**September 30, 2018**	**January 1, 2018**
Receivables from contracts with customers(a)	**37**	40
Contract assets(b)		

(a) Recorded as Trade accounts receivable and reported as Accounts receivable and other in the consolidated balance sheet (Refer also to Note 14). Additionally, our accounts receivable represents the Partnership s unconditional right to recognize revenue for services completed which includes billed and unbilled accounts.

(b) Contract assets primarily relate to the Partnership s right to consideration for services completed but the right is conditioned on something other than the passage of time. Any change in Contract assets is primarily related to the transfer to Accounts receivable when the right to recognize revenue becomes unconditional and the customer is invoiced as well as when revenue increases but remains to be invoiced. The Partnership did not have any Contract assets at January 1, 2018 and September 30, 2018.

Future revenue from remaining performance obligations

In the application of the right to invoice practical expedient, the Partnership s revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized on a monthly basis once the Partnership s performance obligation to provide capacity has been satisfied. The Partnership has also utilized the associated practical expedient that does not require disclosure of information related to its remaining performance obligations.

NOTE 7 DEBT AND CREDIT FACILITIES

(unaudited) (millions of dollars)	September 30, 2018	Weighted Average Interest Rate for the Nine months Ended September 30, 2018	December 31, 2017	Weighted Average Interest Rate for the Year Ended December 31, 2017
TC PipeLines, LP				
Senior Credit Facility due 2021	**60**	3.08%	185	2.41%
2013 Term Loan Facility due 2022	**500**	3.13%	500	2.33%
2015 Term Loan Facility due 2020	**170**	3.02%	170	2.22%
4.65% Unsecured Senior Notes due 2021	**350**	4.65%(a)	350	4.65%(a)
4.375% Unsecured Senior Notes due 2025	**350**	4.375%(a)	350	4.375%(a)
3.90% Unsecured Senior Notes due 2027	**500**	3.90%(a)	500	3.90%(a)
GTN				
5.29% Unsecured Senior Notes due 2020	**100**	5.29%(a)	100	5.29%(a)
5.69% Unsecured Senior Notes due 2035	**150**	5.69%(a)	150	5.69%(a)
Unsecured Term Loan Facility due 2019	**35**	2.82%	55	2.02%
PNGTS				
Revolving Credit Facility due 2023	**19**	3.49%		
5.90% Senior Secured Notes due 2018			30(b)	5.90%(a)
Tuscarora				
Unsecured Term Loan due 2020	**24**	3.00%	25	2.27%
	2,258		2,415	
Less: unamortized debt issuance costs and debt discount	**11**		12	
Less: current portion	**36**		51(b)	
	2,211		2,352	

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(a) Fixed interest rate.

(b) Includes the PNGTS portion due at December 31, 2017 amounting to $5.8 million that was paid on January 2, 2018.

TC PipeLines, LP

The Partnership s Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, maturing November 10, 2021, under which $60 million was outstanding at September 30, 2018 (December 31, 2017 - $185 million), leaving $440 million available for future borrowing. The LIBOR-based interest rate on the Senior Credit Facility was 3.35 percent at September 30, 2018 (December 31, 2017 2.62 percent).

As of September 30, 2018, the variable interest rate exposure related to the 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 3.26 percent (December 31, 2017 2.31 percent). Prior to hedging activities, the LIBOR-based interest rate on the 2013 Term Loan Facility was 3.35 percent at September 30, 2018 (December 31, 2017 2.62 percent).

The LIBOR-based interest rate on the 2015 Term Loan Facility was 3.25 percent at September 30, 2018 (December 31, 2017 2.51 percent).

The 2013 Term Loan Facility and the 2015 Term Loan Facility (collectively, the Term Loan Facilities) and the Senior Credit Facility require the Partnership to maintain a certain leverage ratio (debt to adjusted cash flow [net income plus cash distributions received, extraordinary losses, interest expense, expense for taxes paid or accrued, and depreciation and amortization expense less equity earnings and extraordinary gains]) no greater than 5.00 to 1.00 for each fiscal quarter, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the leverage ratio is to be no greater than 5.50 to 1.00. The leverage ratio was 4.09 to 1.00 as of September 30, 2018.

GTN

GTN s Unsecured Senior Notes, along with GTN s Unsecured Term Loan Facility contain a covenant that limits total debt to no greater than 70 percent of GTN s total capitalization. GTN s total debt to total capitalization ratio at September 30, 2018 was 43.3 percent. The LIBOR-based interest rate on the GTN s Unsecured Term Loan Facility was 3.05 percent at September 30, 2018 (December 31, 2017 2.31 percent).

PNGTS

On April 5, 2018, PNGTS entered into a revolving credit agreement under which PNGTS has the ability to borrow up to $125 million with a variable interest rate based on LIBOR (Revolving Credit Facility). The credit agreement matures on April 5, 2023 and requires PNGTS to maintain a leverage ratio not greater than 5.00 to 1.00. The leverage ratio was 0.38 to 1.00 as of September 30, 2018. The facility is utilized primarily to fund the costs of the PXP expansion project and to finance PNGTS other funding needs. As of September 30, 2018, $19 million was drawn on the Revolving Credit Facility and the LIBOR-based interest rate was 3.49 percent.

On May 10, 2018, PNGTS paid the remaining principal balance of its 5.90% Senior Secured Notes due 2018 (2003 Senior Secured Notes) using its available cash.

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Tuscarora

Tuscarora s Unsecured Term Loan contains a covenant that requires Tuscarora to maintain a debt service coverage ratio (cash available from operations divided by a sum of interest expense and principal payments) of greater than or equal to 3.00 to 1.00. As of September 30, 2018, the ratio was 9.89 to 1.00.

The LIBOR-based interest rate on the Tuscarora s Unsecured Term Loan Facility was 3.23 percent at September 30, 2018 (December 31, 2017 2.49 percent).

At September 30, 2018, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Third Amended and Restated Agreement of Limited Partnership (Partnership Agreement), incurring additional debt and distributions to unitholders. Refer also to Note 19 for important information relating to a distribution reduction to retain cash that will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage our financial metrics in response to the impact of the 2018 FERC Actions on our future operating performance and cashflows.

The principal repayments required of the Partnership on its debt are as follows:

(unaudited)
(millions of dollars)

2018	
2019	36
2020	293
2021	410
2022	500
Thereafter	1,019
	2,258

NOTE 8 PARTNERS EQUITY

ATM equity issuance program (ATM program)

During the nine months ended September 30, 2018, we issued 0.7 million common units under our ATM program (none during the three months ended September 30, 2018) generating net proceeds of approximately $39 million, plus $1 million contributed by the General Partner to maintain its effective two percent general partner interest. The commissions to our sales agents in the nine months ended September 30, 2018 were nil. The net proceeds were used for general partnership purposes.

Class B units issued to TransCanada

The Class B Units issued on April 1, 2015 to finance a portion of the 2015 GTN Acquisition represent a limited partner interest in us and entitle TransCanada to an annual distribution based on 30 percent of GTN s annual distributions as follows: (i) 100 percent of distributions above $20 million through March 31, 2020; and (ii) 25 percent of distributions above $20 million thereafter (Class B Distribution). Additionally, the Class B Distribution will be further reduced by 35 percent, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018 (Class B Reduction). The Class B Reduction was implemented during the first quarter of 2018 following the Partnership s common unit distribution reduction of 35 percent. The Class B Reduction will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit. Refer also to Note 19 for further information on the Partnership s distribution reduction.

For the year ending December 31, 2018, the Class B units equity account will be increased by the Class B Distribution, less the Class B Reduction, until such amount is declared for distribution and paid in the first quarter of 2019. During the nine months ended September 30, 2018, the Class B Distribution was $11 million (30 percent of GTN s total distributable cash flow, which was $31 million less the $20 million annual threshold). After the estimated Class B Reduction for 2018 was applied, the Class B units equity account was increased by $4 million.

For the year ended December 31, 2017, the Class B distribution was $15 million and was declared and paid in the first quarter of 2018.

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NOTE 9 NET INCOME PER COMMON UNIT

Net income per common unit is computed by dividing net income attributable to controlling interests, after deduction of net income attributable to PNGTS former parent, amounts attributable to the General Partner and Class B units, by the weighted average number of common units outstanding.

The amount allocable to the General Partner equals an amount based upon the General Partner s effective two percent general partner interest, plus an amount equal to incentive distributions. Incentive distributions are paid to the General Partner if quarterly cash distributions on the common units exceed levels specified in the Partnership Agreement.

The amount allocable to the Class B units in 2018 equals 30 percent of GTN s distributable cash flow during the year ended December 31, 2018 less $20 million and is further reduced by the estimated Class B Reduction for 2018 (December 31, 2017 less the $20 million threshold and the Class B Reduction was not required). During the three and nine months ended September 30, 2018, $4 million was allocated to the Class B units (2017 - $8 million).

Net income per common unit was determined as follows:

(unaudited) **(millions of dollars, except per common unit amounts)**	**Three months ended September 30,** **2018**	**2017**	**Nine months ended September 30,** **2018**	**2017**
Net income attributable to controlling interests	**62**	54	**231**	186
Net income attributable to PNGTS former parent (a)				(2)
Net income attributable to General and Limited Partners	**62**	54	**231**	184
Incentive distributions allocated to the General Partner (b)		(3)		(9)
Net income attributable to the Class B units (c)	**(4)**	(8)	**(4)**	(8)
Net income attributable to the General Partner and common units	**58**	43	**227**	167
Net income attributable to General Partner s two percent interest	**(1)**	(1)	**(5)**	(3)
Net income attributable to common units	**57**	42	**222**	164
Weighted average common units outstanding *(millions)* basic and diluted	**71.3**	69.4	**71.3**	68.9
Net income per common unit basic and diluted	**$ 0.79**	$ 0.61	**$ 3.11**	$ 2.38

(a) Net income allocable to General and Limited Partners excludes net income attributed to PNGTS former parent as it was allocated to TransCanada and was not allocable to either the general partner, common units or Class B units.

(b) Under the terms of the Partnership Agreement, for any quarterly period, the participation of the incentive distribution rights (IDRs) is limited to the available cash distributions declared. Accordingly, incentive distributions allocated to the General Partner are based on the Partnership s available cash during the current reporting period, but declared and paid in the subsequent reporting period.

(c) During the nine months ended September 30, 2018, 30 percent of GTN s total distributable cash flow was $31 million. After applying the $20 million annual threshold and the estimated Class B Reduction for 2018, $4 million of net income attributable to controlling interests was allocated to the Class B units for both the three and nine months ended September 30, 2018. During the nine months ended September 30, 2017, 30 percent of GTN s total distributable cash flow was $28 million. After applying the $20 million annual threshold, $8 million of net income attributable to controlling interests was allocated to the Class B units for both the three and nine months ended September 30, 2018 (Refer to Note 8). The Class B Reduction did not apply in 2017.

NOTE 10 CASH DISTRIBUTIONS

During the three and nine months ended September 30, 2018, the Partnership distributed $0.65 and $2.30 per common unit, respectively, (September 30, 2017 $1.00 and $2.88 per common unit, respectively) for a total of $47 million and $171 million, respectively, (September 30, 2017 - $74 million and $210 million, respectively).

The distribution paid to our General Partner during the three months ended September 30, 2018 for its effective two percent general partner interest was $1 million (September 30, 2017 - $2 million for the effective two percent interest

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and a $3 million IDR payment). The General Partner did not receive any distributions in respect of its IDRs in the third quarter 2018.

The distribution paid to our General Partner during the nine months ended September 30, 2018 for its effective two percent general partner interest was $4 million along with an IDR payment of $3 million for a total distribution of $7 million (September 30, 2017 - $4 million for the effective two percent interest and a $7 million IDR payment).

NOTE 11 CHANGE IN OPERATING WORKING CAPITAL

(unaudited) (millions of dollars)	Nine months ended September 30, 2018	 2017
Change in accounts receivable and other	**3**	13
Change in other current assets	**1**	1
Change in accounts payable and other current liabilities (a)	**13**	2
Change in accounts payable to affiliates		(3)
Change in accrued interest	**8**	11
Change in operating working capital	**25**	24

(a) Excludes certain non-cash items primarily related to capital accruals.

NOTE 12 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the General Partner. The General Partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the General Partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to conduct the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the General Partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the General Partner in its sole discretion. During the three and nine months ended September 30, 2018 and 2017, the total costs charged to the Partnership by the General Partner were $1 million and $3 million, respectively.

As operator of our pipelines except Iroquois, TransCanada s subsidiaries provide capital and operating services to our pipeline systems. TransCanada s subsidiaries incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, and property and liability insurance costs. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. Therefore, Iroquois does not receive any capital and operating services from TransCanada.

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Capital and operating costs charged to our pipeline systems, except for Iroquois, for the three and nine months ended September 30, 2018 and 2017 by TransCanada s subsidiaries and amounts payable to TransCanada s subsidiaries at September 30, 2018 and December 31, 2017 are summarized in the following tables:

(unaudited) **(millions of dollars)**	**Three months ended September 30, 2018**	**2017**	**Nine months ended September 30, 2018**	**2017**
Capital and operating costs charged by TransCanada s subsidiaries to:				
Great Lakes (a)	**9**	10	**34**	27
Northern Border (a)	**8**	10	**26**	30
GTN	**8**	9	**25**	24
Bison	**2**	2	**5**	4
North Baja	**1**	1	**3**	3
Tuscarora	**1**	1	**3**	3
PNGTS (a)	**2**	2	**7**	6
Impact on the Partnership s net income:				
Great Lakes	**4**	4	**14**	11
Northern Border	**4**	4	**12**	11
GTN	**7**	7	**21**	21
Bison	**2**	2	**5**	4
North Baja	**1**	1	**3**	3
Tuscarora	**1**	1	**3**	3
PNGTS	**1**	1	**4**	4

(unaudited) **(millions of dollars)**	**September 30, 2018**	**December 31, 2017**
Net amounts payable to TransCanada s subsidiaries is as follows:		
Great Lakes (a) (b)	**3**	3
Northern Border (a)	**3**	4
GTN	**3**	3
Bison	**1**	1
North Baja		
Tuscarora		
PNGTS(a)	**1**	1

(a) Represents 100 percent of the costs.

(b) Excludes any amounts owed to affiliates relating to revenue sharing. See discussion below.

Great Lakes

Great Lakes earns significant transportation revenues from TransCanada and its affiliates, some of which are provided at discounted rates and some at maximum recourse rates. For the three and nine months ended September 30, 2018, Great Lakes earned 76 percent and 71 percent, respectively, of transportation revenues from TransCanada and its affiliates (2017 44 percent and 53 percent, respectively).

At September 30, 2018, $12 million was included in Great Lakes receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2017 $20 million).

During 2017, Great Lakes operated under a FERC approved 2013 rate settlement that included a revenue sharing mechanism that required Great Lakes to share with its customers certain percentages of any qualifying revenues earned above certain ROEs. For the year ended December 31, 2017, Great Lakes recorded an estimated revenue sharing provision amounting to $40 million. During the second quarter of 2018, the refund was settled with its customers and a significant portion of the refund was with its affiliates. Under the terms of the 2017 Great Lakes Settlement, beginning in 2018, its revenue sharing provision was eliminated (Refer to our Annual Report on Form 10-K for the year ended December 31, 2017).

During the second quarter of 2018, Great Lakes reached an agreement on the terms of new long-term transportation capacity contracts with its affiliate, ANR Pipeline Company. The contracts are for a term of 15 years from November

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2021 to October 31, 2036 with a total contract value of approximately $1.3 billion. The contracts contain reduction options (i) at any time on or before April 1, 2019 for any reason and (ii) any time before April 2021, if TransCanada is not able to secure the required regulatory approval related to anticipated expansion projects.

PNGTS

PNGTS earns transportation revenues from TransCanada and its affiliates. During the three and nine months ended September 30, 2018, PNGTS earned approximately nil and $1 million, respectively of its transportation revenues from TransCanada and its affiliates (2017 nil and $1 million, respectively).

At September 30, 2018, nil was included in PNGTS receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2017 nil).

In connection with anticipated future commercial opportunities, PNGTS has entered into an arrangement with its affiliates regarding construction of certain facilities on their systems that will be required to fulfill future contracts on the PNGTS system. In the event the anticipated developments do not proceed, PNGTS will be required to reimburse its affiliates for any costs incurred related to the development of these facilities. At September 30, 2018, the total costs incurred by these affiliates was approximately $31 million.

NOTE 13 FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under Accounting Standards Codification (ASC) 820, *Fair Value Measurements and Disclosures*, fair value measurements are characterized in one of three levels based upon the inputs used to arrive at the measurement. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access at the measurement date.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management s best estimate is used.

(b) Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable and other, accounts payable and accrued liabilities, accounts payable to affiliates and accrued interest approximate their fair values because of the short maturity or duration of these instruments, or because the instruments bear a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership s debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates. The fair value of interest rate derivatives is calculated using the income approach, which uses period-end market rates and applies a discounted cash flow valuation model.

Long-term debt is recorded at amortized cost and classified as Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified as Level 2 for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. The estimated fair value of the Partnership s debt as at September 30, 2018 and December 31, 2017 was $2,234 million and $2,475 million, respectively.

Market risk is the risk that changes in market interest rates may result in fluctuations in the fair values or cash flows of financial instruments. The Partnership s floating rate debt is subject to LIBOR benchmark interest rate risk. The Partnership uses interest rate derivatives to manage its exposure to interest rate risk. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

The Partnership s interest rate swaps are structured such that the cash flows of the derivative instruments match those of the variable rate of interest on the 2013 Term Loan Facility. From January 1 to June 30, 2018, the Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps at a weighted average fixed interest rate of 2.31 percent. Beginning July 1, 2018 and until its October 2, 2022 maturity, the 2013 Term Loan Facility was hedged using forward starting swaps at an average rate of 3.26 percent.

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At September 30, 2018, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $17 million (both on a gross and net basis). At December 31, 2017, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $5 million (on both gross and net basis). The change in fair value of interest rate derivative instruments recognized in other comprehensive income was a gain of $3 million and a gain of $12 million for the three and nine months ended September 30, 2018, respectively (2017 nil and gain of $1 million). During the three and nine months ended September 30, 2018, the amount reclassified from other comprehensive income to net income was a gain of $1 million and $4 million, respectively (2017 gain of $1 million and nil, respectively). For the three and nine months ended September 30, 2018, the net realized gain related to the interest rate swaps was nil and $2 million, respectively, and was included in financial charges and other (2017 - nil) (Refer to Note 15).

The Partnership has no master netting agreements; however, it has derivative contracts containing provisions with rights of offset. The Partnership has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. Had the Partnership elected to present these instruments on a net basis, there would be no effect on the consolidated balance sheet as of September 30, 2018 and December 31, 2017.

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with Accounting Standards Codification (ASC) 815, *Derivatives and Hedging*. PNGTS settled its position with a payment of $20.9 million to counterparties at the time of the refinancing and recorded the realized loss in accumulated other comprehensive income as of the termination date. The previously recorded loss was being amortized against earnings over the life of the PNGTS Senior Secured Notes. On May 10, 2018, PNGTS paid the remaining principal balance of its 2003 Senior Secured Notes using its available cash and as a result, our 61.71 percent proportionate share of the net unamortized loss on PNGTS included in other comprehensive income was all amortized against earnings (December 31, 2017 - $1 million). For the three and nine months ended September 30, 2018, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was nil and $1 million (2017 nil and $1 million).

NOTE 14 ACCOUNTS RECEIVABLE AND OTHER

(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
Trade accounts receivable, net of allowance of nil	**37**	40
Imbalance receivable from affiliates	**1**	1
Other	**1**	1
	39	42

NOTE 15 FINANCIAL CHARGES AND OTHER

(unaudited) (millions of dollars)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Interest Expense (a)	**23**	23	**71**	59
			2	1

PNGTS amortization of loss on derivative instruments *(Note 13)*				
Net realized (gain) loss related to the interest rate swaps			**(2)**	
Other Income			**(2)**	(1)
	23	23	**69**	59

(a) Includes amortization of debt issuance costs and discount costs.

NOTE 16 CONTINGENCIES

Great Lakes v. Essar Steel Minnesota LLC, et al. On October 29, 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar Minnesota LLC (Essar Minnesota) and certain Foreign Essar Affiliates (collectively, Essar) for breach of its monthly payment obligation under its transportation services agreement with Great Lakes. Great Lakes sought to recover approximately $33 million for past and future payments due under the agreement. In September 2015, the federal district court judge entered a judgment in the amount of $32.9 million in favor of Great

Lakes. Essar successfully appealed this decision to the United States Court of Appeals for the Eighth Circuit (Eighth Circuit) based on an allegation of improper jurisdiction and various other rulings by the federal district judge. The Eighth Circuit vacated Great Lakes judgment against Essar finding that there was no federal jurisdiction. Essar Minnesota filed for bankruptcy in July 2016.

Great Lakes filed a claim against Essar Minnesota in the bankruptcy court. The bankruptcy court approved Great Lakes unsecured claim in the amount of $31.5 million in April 2017. In May 2017, the federal district court awarded Essar Minnesota approximately $1.2 million for costs, including recovery of the premium for the performance bond Essar was required to post pending appeal. Following Essar s successful appeal and award of $1.2 million of costs, Great Lakes was required to release the $1.2 million into the bankruptcy estates.

The Foreign Essar Affiliates have not filed for bankruptcy and Great Lakes case against the Foreign Essar Affiliates in Minnesota state court remains pending. The Foreign Essar Affiliates gave an offer of judgment (Offer of Judgment) in the federal district court proceeding whereby the Foreign Essar Affiliates agreed to satisfy any judgment awarded to Great Lakes. The Foreign Essar Affiliates dispute that the Offer of Judgment is enforceable because the federal court judgment was vacated on appeal. Great Lakes has obtained a consent order from the bankruptcy court permitting it to petition the state court to enforce the Offer of Judgment. If unsuccessful in state court, Great Lakes can return to bankruptcy court for an order permitting it to proceed to trial in state court on its claims under the transportation services agreement against the Foreign Essar Affiliates.

At September 30, 2018, Great Lakes is unable to estimate the timing or the extent to which its claim will be recoverable in the bankruptcy proceedings, therefore, it did not recognize any gain contingency on its outstanding claim against Essar.

Additionally, at September 30, 2018, the Partnership is not aware of any contingent liabilities that would have a material adverse effect on the Partnership s financial condition, results of operations or cash flows.

NOTE 17   VARIABLE INTEREST ENTITIES

In the normal course of business, the Partnership must re-evaluate its legal entities under the current consolidation guidance to determine if those that are considered to be VIEs are appropriately consolidated or if they should be accounted for under other GAAP. A variable interest entity (VIE) is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity s operations through voting rights or do not substantively participate in the gains or losses of the entity. A VIE is appropriately consolidated if the Partnership is considered to be the primary beneficiary. The VIE s primary beneficiary is the entity that has both (1) the power to direct the activities of the VIE that most significantly impact the VIEs economic performance and (2) the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

As a result of its analysis, the Partnership continues to consolidate all legal entities in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs where the Partnership is not the primary beneficiary, but has a variable interest in the entity, are accounted for as equity investments.

Consolidated VIEs

The Partnership s consolidated VIEs consist of the Partnership s ILPs that hold interests in the Partnership s pipeline systems. After considering the purpose and design of the ILPs and the risks that they were designed to create and pass through to the Partnership, the Partnership has concluded that it is the primary beneficiary of these ILPs because of the significant amount of variability that it absorbs from the ILPs economic performance.

The assets and liabilities held through these VIEs that are not available to creditors of the Partnership and whose investors have no recourse to the credit of the Partnership are held through GTN, Tuscarora, Northern Border, Great Lakes, PNGTS and Iroquois due to their third party debt. The following table presents the total assets and liabilities of these entities that are included in the Partnership s consolidated balance sheets:

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(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
ASSETS (LIABILITIES) (a)		
Cash and cash equivalents	**13**	19
Accounts receivable and other	**26**	30
Inventories	**7**	6
Other current assets	**3**	5
Equity investments	**1,196**	1,213
Property, plant and equipment, net	**1,118**	1,133
Other assets	**1**	1
Accounts payable and accrued liabilities	**(21)**	(24)
Provision for revenue sharing	**(9)**	
Accounts payable to affiliates, net	**(47)**	(42)
Distributions payable		(1)
Accrued interest	**(5)**	(2)
Current portion of long-term debt	**(36)**	(51)
Long-term debt	**(291)**	(308)
Other liabilities	**(27)**	(26)
Deferred state income tax	**(10)**	(10)

(a) North Baja and Bison, which are also assets held through our consolidated VIEs, are excluded as the assets of these entities can be used for purposes other than the settlement of the VIE s obligations.

NOTE 18 INCOME TAXES

The Partnership s income taxes relate to business profits tax (BPT) levied at the partnership (PNGTS) level by the state of New Hampshire. As a result of the BPT, PNGTS recognizes deferred taxes related to temporary differences between the financial statement carrying amount of existing assets and liabilities and their respective tax bases. The deferred taxes at September 30, 2018 and December 31, 2017 relate primarily to utility plant. At September 30, 2018 and December 31, 2017 the New Hampshire BPT effective tax rate was 3.8 percent for both periods and was applied to PNGTS taxable income.

(unaudited) (millions of dollars)	Three months ended September 30, 2018	 2017	Nine months ended September 30, 2018	 2017
State income taxes				
Current			**1**	1
Deferred				
			1	1

NOTE 19 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through November 9, 2018, the date the financial statements were issued, and concluded there were no events or transactions during this period that would require recognition or disclosure in the consolidated financial statements other than what is disclosed here and/or those already disclosed in the preceding notes.

On October 22, 2018, the board of directors of the General Partner declared the Partnership s third quarter 2018 cash distribution in the amount of $0.65 per common unit payable on November 14, 2018 to unitholders of record as of November 2, 2018. The declared distribution totaled $47 million and is payable in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $1 million to the General Partner for its effective two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the third quarter 2018. This distribution as well as our first quarter and second quarter 2018 distributions each represent a 35 percent reduction compared to the Partnership s fourth quarter 2017 distribution of $1.00 per common unit. Cash retained by the Partnership will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage our financial metrics in response to the impact of the 2018 FERC Actions on our future operating performance and cash flows.

Northern Border declared its September 2018 distribution of $15 million on October 10, 2018, of which the Partnership received its 50 percent share or $7 million on October 31, 2018.

Great Lakes declared its third quarter 2018 distribution of $22 million on October 17, 2018, of which the Partnership received its 46.45 percent share or $10 million on November 1, 2018.

PNGTS declared its third quarter 2018 distribution of $8 million on October 23, 2018, of which $3 million was paid to its non-controlling interest owner on November 1, 2018.

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

The following discussion and analysis should be read in conjunction with the unaudited financial statements and notes included in Item 1 Financial Statements of this Quarterly Report on Form 10-Q, as well as our Annual Report on Form 10-K for the year ended December 31, 2017.

RECENT BUSINESS DEVELOPMENTS

In December 2016, FERC issued Docket No. PL17-1-000 requesting initial comments regarding how to address any double recovery resulting from FERC s current income tax allowance and rate of return policies that had been in effect since 2005.

Docket No. PL17-1-000 is a direct response to *United Airlines, Inc., et al. v. FERC*, a decision issued by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016 in which the D.C. Circuit directed FERC to explain how a pass-through entity such as an MLP receiving a tax allowance and a return on equity derived from the DCF methodology did not result in double recovery of taxes.

On December 22, 2017, the President of the United States signed into law the 2017 Tax Act. This legislation provides for major changes to U.S. corporate federal tax law including a reduction of the federal corporate income tax rate. We are a non-taxable limited partnership for federal income tax purposes and federal income taxes owed as a result of our earnings are the responsibility of our partners. Therefore, no amounts have been recorded in the Partnership s financial statements with respect to federal income taxes as a result of the 2017 Tax Act.

On March 15, 2018, FERC issued the following: (1) the Revised Policy Statement, (2) the NOPR and (3) the NOI. On July 18, 2018, FERC issued (1) an Order on Rehearing and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR. The Final Rule became effective September 13, 2018, and is subject to requests for further rehearing and clarification. Each of the 2018 FERC Actions is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates

The Revised Policy Statement changes FERC s long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regard to ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity s income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as the refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on Tax Law Changes for Interstate Natural Gas Companies

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rates settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantifies the rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. Pipelines filing the one-time report will have four options:

• Option 1: make a limited NGA Section 4 filing to reduce its rates by the reduction in its cost of service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline s FERC Form 501-G shows the pipeline s estimated ROE as being 12 percent or less. Under the Final Rule and notwithstanding the Revised Policy Statement, a pipeline organized as an MLP is not required to eliminate its income tax allowance but, instead can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance, along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline s rate base used for rate-making purposes;

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• Option 2: commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. If the pipeline commits to file either by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date;

• Option 3: file a statement explaining its rationale for why it does not believe the pipeline s rates must change; and

• Option 4: take no action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates

In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, is required by FERC related to the ADIT that were reserved in anticipation of being paid to the IRS, but which no longer accurately reflect the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated rates or earnings.

As noted above, FERC s Order on Rehearing provided guidance with regard to ADIT for MLP pipelines, finding that if an MLP pipeline s income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

Partnership Specific Considerations

The Partnership s pipeline systems do not currently have a requirement to file for new rates earlier than 2022 as a result of their existing rate settlements. However, the timing may be accelerated by the 2018 FERC Actions. The 2018 FERC Actions directly address two components of our pipeline systems cost-of-service based rates: the allowance for income taxes and the amount of ADIT. The 2018 FERC Actions also noted that precise treatment of entities with more ambiguous ownership structures must be separately resolved on a case-by-case basis, including those partially owned by corporations such as Great Lakes, Northern Border, Iroquois and PNGTS pipelines. Additionally, any FERC mandated rate reduction will not affect negotiated rate or non-recourse rate contracts. Approximately half of the Partnership s share of revenues (including those accounted for in the earnings of our equity investments) are derived from contracts that are negotiated or non-recourse which we do not expect to be impacted by the 2018 FERC Actions.

On October 16, 2018, GTN filed an uncontested settlement amongst GTN and its customers with the FERC to address the changes proposed by the 2018 FERC Actions within its rates via an amendment to its prior 2015 settlement. Among the terms of the 2018 GTN Settlement, GTN has agreed to a refund of approximately $10 million in 2018 to its firm customers reflective of reduced rates for the ten months ended October 31, 2018, as well as to reduce its existing maximum system rates by 10 percent effective January 1, 2019 until December 31, 2019. The existing maximum rates will then decrease by an additional 6.6 percent for the period January 1, 2020 through December 31, 2021. GTN is required to have new rates in effect on January 1, 2022. These reductions will replace the 8 percent reduction in GTN s reservation rates in 2020 agreed upon as part of the GTN s last settlement in 2015. Furthermore, GTN and its customers have agreed upon a moratorium on further rate changes prior to January 1, 2022, providing a greater degree of regulatory certainty for GTN going forward. The 2018 GTN Settlement will also reflect an elimination of tax allowance previously recovered in rates along with ADIT for rate-making purposes. The uncontested settlement, subject to approval by the FERC, will relieve GTN of its obligation to file a Form 501-G.

On October 11, 2018, North Baja elected to make a limited NGA Section 4 filing to reduce its recourse rates by approximately 11 percent and eliminate its deferred income tax balances previously used for rate setting (Option 1). The reduction in North Baja s recourse rates is not expected to have a material impact on North Baja s results given that over 80 percent of its contracts are negotiated.

On October 12, 2018, Iroquois made a filing with the FERC and requested a waiver of its requirement to file a FERC Form No. 501-G from FERC based on its existing moratorium precluding rate changes prior to September 2020.

PNGTS and Bison filed their respective FERC Form No. 501-G Forms on October 11, 2018 and November 8, 2018, respectively along with explanations why rate changes were not required (Option 3).

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The Partnership continues to re-examine its next steps following the changes summarized above and alternatives now available under the Final Rule. As noted above, the change in the Final Rule to allow MLPs to remove the ADIT liability from rate base, and thus increase net recoverable rate base, would partially mitigate the loss of the tax allowance in cost-of-service based rates. The Partnership s remaining pipeline systems, Northern Border, Great Lakes and Tuscarora, are scheduled to file their respective FERC Form No. 501-Gs by December 6, 2018. Thus, the Partnership anticipates finalizing its regulatory approach for all of the Partnership s pipeline systems by the end of 2018.

Following the 2018 GTN Settlement, the current estimated overall impact of the tax-related changes to our revenue and cash flow is a reduction of approximately $20-$30 million per year on an annualized basis beginning in 2019. This estimate could change due to numerous assumptions around the resolution of related issues as they are applied individually across our pipeline systems.

Outlook of Our Business

TransCanada, the ultimate parent company of our General Partner, has historically viewed us as an element of its capital financing strategy. Following the 2018 FERC Actions initially proposed in March 2018, TransCanada stated that further dropdowns to the Partnership were no longer considered to be a viable funding lever. Therefore, our traditional source of growth is not accessible under the current circumstances. TransCanada continues to monitor developments in the Partnership in order to determine whether the Partnership might be restored as a competitive financing option in the future.

We continue to strategically position the Partnership for the long term to further minimize any negative effects of the 2018 FERC Actions. Where market demand exists, we are prudently pursuing organic expansion opportunities that economically and efficiently expand our existing infrastructure to meet evolving market requirements.

Our focus remains on the safe and reliable operation of our pipeline assets and we expect our assets to continue to serve their customers as designed.

Impairment Considerations

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions, which cannot be known with certainty, that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ.

We review property, plant and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate the possibility of impairment. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, an impairment test is not performed.

We continue to monitor developments following the Final Rule on the 2018 FERC Actions. We will incorporate results to date, future filings for the Partnership s assets and FERC responses to others in the industry into our annual goodwill impairment test as well as normal our review of property, plant and equipment and equity investments for recoverability.

At September 30, 2018, the goodwill and the equity method goodwill balances related to Tuscarora and Great Lakes amounted to $82 million and $260 million (December 31, 2017- $82 million and $260 million), respectively. Additionally, the estimated fair values of Tuscarora and our investment in Great Lakes exceeded their carrying values by less than 10 percent in the most recent valuations. There is a risk that the goodwill balances related to Tuscarora and Great Lakes could be negatively impacted by the 2018 FERC Actions, once finalized or by other changes in management s estimates of fair value resulting in an impairment charge.

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Other Business Developments

NOI on Certificate Policy Statement - FERC issued a Notice of Inquiry on April 19, 2018 (Certificate Policy Statement NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the Certificate Policy Statement NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. Any proposed changes to the current policy will be prospective only and it is expected that FERC will take many months to determine whether there will be any changes to proposed natural gas pipeline projects. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

Portland XPress Project - As noted in our Annual Report for the year ended December 31, 2017, the in-service dates of the PXP project are being phased-in over a three-year period beginning November 1, 2018. During the second quarter, PNGTS filed the required applications with FERC for all three phases of the project, which includes an amendment to its Presidential Permit and an increase in its certificated capacity through the addition of a compressor unit at its jointly owned facility with Maritimes and Northeast Pipeline LLC to bring additional volumes of natural gas to New England. On August 28, 2018, FERC issued a positive Environmental Assessment for Phase II of the PXP project. PNGTS expects the Environmental Assessment for Phase III will be issued during the late 2018.

HOW WE EVALUATE OUR OPERATIONS

We use certain non-GAAP financial measures that do not have any standardized meaning under GAAP as we believe they enhance the understanding of our operating performance. We use the following non-GAAP measures:

EBITDA

We use EBITDA as a proxy of our operating cash flow and current operating profitability.

Distributable Cash Flows

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period.

Please see Non-GAAP Financial Measures: EBITDA and Distributable Cash Flow for more information.

RESULTS OF OPERATIONS

Our ownership interests in eight pipelines were our only material sources of income during the period. Therefore, our results of operations and cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems.

(unaudited) (millions of dollars)	Three months ended September 30, 2018	2017	$ Change(a)	% Change(a)	Nine months ended September 30, 2018	2017	$ Change(a)	% Change(a)
Transmission revenues	**103**	100	3	3	**328**	313	15	5
Equity earnings	**34**	27	7	26	**129**	87	42	48
Operating, maintenance and administrative	**(24)**	(24)			**(73)**	(74)	1	1
Depreciation	**(25)**	(25)			**(73)**	(73)		
Financial charges and other	**(23)**	(23)			**(69)**	(59)	(10)	(17)
Net income before taxes	**65**	55	10	18	**242**	194	48	25
State income taxes					**(1)**	(1)		
Net income	**65**	55	10	18	**241**	193	48	25
Net income attributable to non-controlling interests	**3**	1	2	*	**10**	7	3	43
Net income attributable to controlling interests	**62**	54	8	15	**231**	186	45	24

(a) Positive number represents a favorable change; bracketed or negative number represents an unfavorable change.

* More than 100 percent

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Three Months Ended September 30, 2018 compared to Same Period in 2017

The Partnership s net income attributable to controlling interests increased by $8 million in the three months ended September 30, 2018 compared to 2017, an increase of $0.09 per common unit, mainly due to the following:

Transmission revenues Revenues were slightly higher due largely to the net effect of:

- Lower net revenue from GTN primarily due to the $9 million provision for revenue sharing recorded during the third quarter of 2018 as part of the 2018 GTN Settlement whereby GTN agreed to refund $10 million to its recourse rate customers from January 1 through October 31, 2018. Additionally, GTN generated lower revenues from its short-term discretionary services compared to the same period in 2017. These decreases, however, were partially offset by higher incremental long-term services sold by GTN associated with the increased available upstream capacity following debottlenecking activities on TransCanada s pipelines;

- Higher revenue from PNGTS primarily due to incremental contracting from PNGTS Continent-to-Coast contracts for approximately 82,000 Dth/day (C2C contracts) for a term of 15 years;

- Increase in short-term firm transportation services sold by North Baja.

Equity Earnings - The $7 million increase was primarily due to higher equity earnings from Great Lakes mainly due to the elimination of Great Lakes revenue sharing mechanism beginning in 2018 as part of the 2017 Great Lakes Settlement. Additionally, there was a slight increase in Great Lakes short-term incremental sales during the current period.

Net income attributable to non-controlling interests - The Partnership s net income attributable to non-controlling interests was higher due to the increase in PNGTS net income as a result of its higher revenue.

Nine months Ended September 30, 2018 compared to Same Period in 2017

The Partnership s net income attributable to controlling interests increased by $45 million in the nine months ended September 30, 2018 compared to 2017, an increase of $0.54 per common unit, mainly due to the following:

Transmission revenues Revenues were higher due to the following:

- Higher net revenue from GTN primarily due to incremental long-term services sold by GTN associated with the increased available upstream capacity following debottlenecking activities on TransCanada s pipelines offset by lower revenues from its short-term discretionary services compared to the same period in 2017. The increase was further offset by the $9 million provision for revenue sharing recorded at the end of September 30, 2018 as part of the 2018 GTN Settlement whereby GTN agreed to refund $10 million to its recourse rate customers from January 1 to October 31, 2018;

- Higher revenue from PNGTS primarily due to incremental contracting from PNGTS C2C contracts partially offset by certain expiring winter contracts;

- Increase in short-term firm transportation services sold by North Baja.

Equity Earnings - The $42 million increase was primarily due to the inclusion of equity earnings from Iroquois for the full nine months of 2018 compared to only four months in 2017 (our 49.34 percent ownership was effective June 1, 2017), as well as the increase in Iroquois short-term discretionary services during the 2018 period as a result of the colder winter weather in the Northeast. Additionally, equity earnings from Great Lakes increased as a result of incremental seasonal winter sales during the current period and the elimination of Great Lakes revenue sharing mechanism beginning in 2018 as part of the 2017 Great Lakes Settlement. The additional earnings were partially offset by lower revenues and earnings from Northern Border resulting from its rate reduction as part of the 2017 Northern Border Settlement.

Financial charges and other - The $10 million increase was primarily attributable to additional borrowings to finance the acquisition of a 49.34 percent interest in Iroquois and an additional 11.81 percent interest in PNGTS (the 2017 Acquisition).

Net income attributable to non-controlling interests - The Partnership s net income attributable to non-controlling interests was higher due to the increase in PNGTS net income as a result of its higher revenue.

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Net Income Attributable to Common Units and Net Income per Common Unit

2018

As discussed in Note 9 within Item 1 Financial Statements, we allocated $4 million of the Partnership s net income attributable to controlling interests to the Class B units in the three and nine months ended September 30, 2018, respectively, representing the excess of 30 percent of GTN s distribution over the 2018 threshold level of $20 million, which was further reduced by the estimated Class B Reduction for 2018. This allocation reduced net income attributable to the common units and accordingly, reduced net income per common unit by approximately $0.05 cents for both the three and nine months ended September 30, 2018, respectively.

2017

We allocated $8 million of the Partnership s net income attributable to controlling interests to the Class B units in the three and nine months ended September 30, 2017, respectively, representing the excess of 30 percent of GTN s distribution over the 2017 threshold level of $20 million. This allocation reduced net income attributable to the common units and accordingly, reduced net income per common unit by approximately $0.12 for both the three and nine months ended September 30, 2017, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity and cash flows include distributions received from our equity investments, operating cash flows from our subsidiaries, public offerings of debt and equity, term loans and our Senior Credit Facility. The Partnership funds its operating expenses, debt service and cash distributions (including those distributions made to TransCanada through our General Partner and as holder of all our Class B units) primarily with operating cash flow.

Given the magnitude of future cash flow decreases as a result of the 2018 FERC Actions, the Partnership reduced its 2018 quarterly distribution to $0.65 per common unit, a 35 percent reduction from the fourth quarter 2017 distribution of $1.00 per common unit. Cash retained by the Partnership will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage its financial metrics.

Currently, we are continuing to use the cash retained from reduction of distributions to further deleverage our balance sheet. As of September 30, 2018, our cash and cash equivalents totaled $48 million, an increase of $15 million or 45 percent from December 31, 2017. In 2018 through the end of the third quarter, we reduced the outstanding balance of our Senior Credit Facility by 68 percent, from $185 million at December 31, 2017 to $60 million at September 30, 2018. We believe our cash position, remaining borrowing capacity on our Senior Credit Facility (see table below), and our operating cash flows are adequate to fund our short-term liquidity requirements, including the revised distributions to our unitholders, ongoing capital expenditures, required debt repayments.

The following table sets forth the available borrowing capacity under the Partnership s Senior Credit Facility:

(unaudited) (millions of dollars)	September 30, 2018	December 31, 2017
Total capacity under the Senior Credit Facility	500	500
Less: Outstanding borrowings under the Senior Credit Facility	60	185
Available capacity under the Senior Credit Facility	440	315

The principal sources of liquidity on our pipeline systems are cash generated from operating activities, long-term debt offerings, bank credit facilities and equity contributions from their owners. Our pipeline systems have historically funded operating expenses, debt service and cash distributions to their owners primarily with operating cash flow. However, since the fourth quarter of 2010, Great Lakes has funded its debt repayments with cash calls to its owners.

Capital expenditures of our pipeline systems are funded by a variety of sources, including cash generated from operating activities, borrowings under bank credit facilities, issuance of senior unsecured notes or equity contributions from our pipeline systems owners. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends on their financial position and general market conditions.

The Partnership s pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs which, although limited by FERC, allow them to request credit support as circumstances dictate.

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Cash Flow Analysis for the Nine months Ended September 30, 2018 compared to Same Period in 2017

(unaudited) **(millions of dollars)**	**Nine months ended September 30,** **2018**	**2017**
Net cash provided by (used in):		
Operating activities	**354**	311
Investing activities	**(24)**	(756)
Financing activities	**(315)**	454
Net increase in cash and cash equivalents	**15**	9
Cash and cash equivalents at beginning of the period	**33**	64
Cash and cash equivalents at end of the period	**48**	73

Operating Cash Flows

Net cash provided by operating activities increased by $43 million in the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to the net effect of:

- addition of distributions from Iroquois for the full nine months in 2018 as compared to the period from June 1 to the end of September in 2017;
- higher distributions received from Great Lakes primarily due to an increase in its revenue;
- higher cash flow from operations at PNGTS and North Baja primarily resulting from an increase in their revenues; and
- higher interest expense attributable to additional borrowings to finance the 2017 Acquisition;

Investing Cash Flows

Net cash used in investing activities decreased by $732 million during the nine months ended September 30, 2018 compared to the same period in 2017 due to the net effect of:

- $646 million total cash payments to TransCanada during 2017 for the 2017 Acquisition;
- $83 million equity contribution to Northern Border representing our 50 percent share of a requested capital contribution to reduce the outstanding balance of its revolving credit facility; and

- $8 million unrestricted cash distribution received from Iroquois during the nine months ended September 30, 2018 representing a return of investment, which is a $5 million increase compared to the nine months ended September 30 2017.

Financing Cash Flows

The net increase in cash used in financing activities was approximately $769 million in the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to the net effect of:

- $157 million in net debt repayments in 2018 compared to $568 million in net debt issuance in 2017 primarily due to the issuance of $500 million 3.90% Senior Notes on May 25, 2017 to partially finance the 2017 Acquisition;
- $39 million decrease in distributions paid on our common units and to our General Partner in respect of its two percent general partner interest and IDRs as a result of the 35 percent reduction in distributions declared from the fourth quarter 2017 distribution of $1.00 per common unit to $0.65 per common unit beginning with the first quarter of 2018;
- $7 million decrease in distributions paid to Class B units in 2018 as compared to 2017;
- $86 million decrease in our ATM equity issuances in the nine months ended September 30, 2018, as compared to the same period in 2017; and
- $6 million increase in distributions paid to non-controlling interests due to higher distributions paid by PNGTS.

Short-Term Cash Flow Outlook

Operating Cash Flow Outlook

Northern Border declared its September 2018 distribution of $15 million on October 10, 2018, of which the Partnership received its 50 percent share or $7 million. The distribution was paid on October 31, 2018.

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Great Lakes declared its third quarter 2018 distribution of $22 million on October 17, 2018, of which the Partnership received its 46.45 percent share or $10 million. The distribution was paid on November 1, 2018.

Iroquois declared its third quarter 2018 distribution of $29 million on October 22, 2018, of which the Partnership received its 49.34 percent share or $14 million on November 1, 2018.

Our equity investee Iroquois has $2 million of scheduled debt repayments for the remainder of 2018 and Iroquois debt repayments are expected to be funded through its cash flow from operations.

Investing Cash Flow Outlook

The Partnership made an equity contribution to Great Lakes of $4 million in the first quarter of 2018. This amount represents the Partnership s 46.45 percent share of a $9 million cash call from Great Lakes to make a scheduled debt repayment. The Partnership expects to make an additional $5 million equity contribution to Great Lakes in the fourth quarter of 2018 to further fund debt repayments. This is consistent with prior years.

Our consolidated entities have commitments of $10 million as of September 30, 2018 in connection with various maintenance and general plant projects.

Financing Cash Flow Outlook

On October 23, 2018, the board of directors of our General Partner declared the Partnership s third quarter 2018 cash distribution in the amount of $0.65 per common unit payable on November 14, 2018 to unitholders of record as of November 2, 2018. Please see Liquidity and Capital Resources and Note 19 within Item 1 Financial Statements for additional disclosures.

PNGTS declared its third quarter 2018 distribution of $8 million on October 23, 2018, of which $3 million was paid to its non-controlling interest owner on November 1, 2018.

Non-GAAP Financial Measures: EBITDA and Distributable Cash Flow

EBITDA is an approximate measure of our operating cash flow during the current earnings period and reconciles directly to the most comparable measure of net income. It measures our earnings before deducting interest, taxes, depreciation and amortization, net income attributable to non-controlling interests, and includes earnings from our equity investments.

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period and reconcile directly to the net income amount presented.

Total distributable cash flow includes EBITDA *plus:*

- Distributions from our equity investments

less:

- Earnings from our equity investments,
- Equity allowance for funds used during construction (Equity AFUDC),
- Interest expense,
- Income taxes,
- Distributions to non-controlling interests,
- Distributions to TransCanada as the former parent of PNGTS, and
- Maintenance capital expenditures from consolidated subsidiaries.

Distributable cash flow is computed net of distributions declared to the General Partner and distributions allocable to Class B units. Distributions declared to the General Partner are based on its effective two percent interest plus an amount equal to incentive distributions. For the year ending December 31, 2018, distributions allocable to the Class B units (30 percent of GTN s 2018 distributable cash flow less $20 million) will be further reduced by the Class B Reduction. The Class B Reduction was implemented during the first quarter of 2018 following the Partnership s common unit distribution reduction of 35 percent and will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit. The Class B Reduction was not required during 2017.

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Distributable cash flow and EBITDA are performance measures presented to assist investors in evaluating our business performance. We believe these measures provide additional meaningful information in evaluating our financial performance and cash generating performance.

The non-GAAP measures described above are provided as a supplement to GAAP financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP. Additionally, these measures as presented may not be comparable to similarly titled measures of other companies.

Reconciliations of Net Income to EBITDA and Distributable Cash Flow

The following table represents a reconciliation of the non-GAAP financial measures of EBITDA, total distributable cash flow and distributable cash flow, to the most directly comparable GAAP financial measure of Net Income:

(unaudited) (millions of dollars)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Net income	**65**	55	**241**	193
Add:				
Interest expense(a)	**23**	23	**71**	60
Depreciation and amortization	**25**	25	**73**	73
Income taxes			**1**	1
EBITDA	**113**	103	**386**	327
Add:				
Distributions from equity investments(b)				
Northern Border	**22**	21	**60**	61
Great Lakes	**10**	1	**49**	28
Iroquois (c)	**14**	14	**42**	28
	46	36	**151**	117
Less:				
Equity earnings:				
Northern Border	**(16)**	(16)	**(49)**	(50)
Great Lakes	**(9)**	(2)	**(45)**	(24)
Iroquois	**(9)**	(9)	**(35)**	(13)
	(34)	(27)	**(129)**	(87)
Less:				
Interest expense (a)	**(23)**	(23)	**(71)**	(60)
Income taxes			**(1)**	(1)
Distributions to non-controlling interests(d)	**(3)**	(2)	**(12)**	(10)
Distributions to TransCanada as PNGTS former parent(e)				(1)
Maintenance capital expenditures (f)	**(11)**	(9)	**(21)**	(26)
	(37)	(34)	**(105)**	(98)
Total Distributable Cash Flow	**88**	78	**303**	259
General Partner distributions declared (g)	**(1)**	(5)	**(3)**	(13)
Distributions allocable to Class B units (h)	**(4)**	(8)	**(4)**	(8)

Distributable Cash Flow	**83**	65	**296**	238

(a) Interest expense as presented includes net realized loss or gain related to the interest rate swaps and amortization of realized loss on PNGTS derivative instruments. Refer to Note 15 within Item 1 Financial Statements .

(b) Amounts are calculated in accordance with the cash distribution policies of each of our equity investments. Distributions from our equity investments represent our respective share of these entities quarterly distributable cash during the current reporting period.

(c) This amount represents our proportional 49.34 percent share of the distribution declared by our equity investee Iroquois during the current reporting period and includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $2.6 million and $7.8 million, respectively, for the three and nine months ended September 30, 2018 (2017 - $2.6 million and $5.2 million).

(d) Distributions to non-controlling interests represent the respective share of our consolidated entities distributable cash from earnings not owned by us during the periods presented.

(e) Distributions to TransCanada as PNGTS former parent represent TransCanada s respective share of PNGTS distributable cash not owned by us during the periods presented.

(f) The Partnership s maintenance capital expenditures include expenditures made to maintain, over the long term, the operating capacity, system integrity and reliability of our pipeline assets. This amount represents the Partnership s and its consolidated subsidiaries maintenance capital expenditures and does not include the Partnership s share of maintenance capital expenditures for our equity investments. Such amounts are reflected in Distributions from equity investments as those amounts are withheld by those entities from their quarterly distributable cash.

(g) Distributions declared to the General Partner for the three and nine months ended September 30, 2018 did not trigger any incentive distribution (2017 $3 million and $9 million).

(h) During the nine months ended September 30, 2018, 30 percent of GTN s total distributions amounted to $31 million. After applying the $20 million annual threshold and an estimate of Class B Reduction for 2018, $4 million was allocated to the Class B units for both the three and nine months ended September 30, 2018. During the nine months ended September 30, 2017, 30 percent of GTN s total distributions amounted to $28 million. After applying the $20 million annual threshold, $8 million was allocated to the Class B units for both the three and nine months ended September 30, 2017. The Class B reduction was not required during 2017. Please read Notes 8 and 9 within Item 1 Financial Statements for additional disclosures on the Class B units.

Three months ended September 30, 2018 Compared to Same Period in 2017

Our EBITDA was higher for the third quarter of 2018 compared to the same period in 2017 primarily due to higher equity earnings and an increase in our revenues during the period as discussed in more detail under the Results of Operations section.

Our distributable cash flow increased by $18 million in the third quarter of 2018 compared to the same period in 2017 due to the net effect of:

- higher EBITDA from PNGTS and North Baja due to an increase in their revenues generated during the third quarter of 2018 partially offset by lower EBITDA from GTN due to its lower net revenues during the period;

- higher distributions from Great Lakes due to the increase in revenue during the third quarter of 2018;
- higher maintenance capital expenditures compared to the third quarter of 2017 primarily due to timing of pipeline reliability projects on GTN;
- reduction in our declared distributions which did not result in any IDR allocation to our General Partner during the current period; and
- reduction in distributions allocable to Class B units caused by the Class B Reduction, which was prompted by the reduction in distributions declared for common units.

Nine months ended September 30, 2018 Compared to Same Period in 2017

Our EBITDA was higher for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to higher equity earnings and an overall increase in our revenues during the period as discussed in more detail under the Results of Operations section.

Our distributable cash flow increased by $58 million in the nine months ended September 30, 2018 compared to the same period in 2017 due to the net effect of:

- higher EBITDA from GTN, PNGTS and North Baja due to an increase in their revenues generated during the nine months ended September 30, 2018;
- three quarters of distributions received from Iroquois during the nine months ended September 30, 2018 compared to two distributions received during the previous period (ownership of 49.34 percent was effective June 1, 2017);
- higher distributions from Great Lakes due to the increase in revenue generated during the nine months ended September 30, 2018;

- lower maintenance capital expenditures compared to 2017 during which there were major compression equipment overhauls on GTN;
- increased interest expense due to additional borrowings to finance the 2017 Acquisition;
- reduction in declared distributions which did not result in any IDR allocation to our General Partner during the current period; and
- reduction in distributions allocable to Class B units caused by the Class B Reduction, which was prompted by the reduction in distributions declared for common units.

Contractual Obligations

The Partnership s Contractual Obligations

The Partnership s contractual obligations related to debt as of September 30, 2018 included the following:

		Payments Due by Period				
(unaudited) (millions of dollars)	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**	**Weighted Average Interest Rate for the Nine months Ended September 30, 2018**
TC PipeLines, LP						
Senior Credit Facility due 2021	60			60		3.08%
2013 Term Loan Facility due 2022	500			500		3.13%
2015 Term Loan Facility due 2020	170		170			3.02%
4.65% Senior Notes due 2021	350		350			4.65%(a)
4.375% Senior Notes due 2025	350				350	4.375%(a)
3.9% Senior Notes due 2027	500				500	3.90%(a)
GTN						
5.29% Unsecured Senior Notes due 2020	100		100			5.29%(a)
5.69% Unsecured Senior Notes due 2035	150				150	5.69%(a)
Unsecured Term Loan Facility due 2019	35	35				2.82%
PNGTS						
Revolving Credit Facility due 2023	19				19	3.49%
Tuscarora						
Unsecured Term Loan due 2020	24	1	23			3.00%
	2,258	36	643	560	1,019	

(a) Fixed interest rate

The Partnership s long-term debt results in exposures to changing interest rates. The Partnership uses derivatives to assist in managing its exposure to interest rate risk. Refer to Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional information regarding the derivatives.

The fair value of the Partnership s long-term debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates. The estimated fair value of the Partnership s debt at September 30, 2018 was $2,234 million.

Please read Note 7 within Item 1. Financial Statements for additional information regarding the Partnership s debt.

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Summary of Northern Border s Contractual Obligations

Northern Border s contractual obligations related to debt as of September 30, 2018 included the following:

		Payments Due by Period (a)				
(unaudited) (millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Nine months Ended September 30, 2018
$200 million Credit Agreement due 2020	15		15			3.00%
7.50% Senior Notes due 2021	250		250			7.50%(b)
	265		265			

(a) Represents 100 percent of Northern Border s debt obligations

(b) Fixed interest rate

As of September 30, 2018, $15 million was outstanding under Northern Border s $200 million revolving credit agreement, leaving $185 million available for future borrowings. At September 30, 2018, Northern Border was in compliance with all of its financial covenants.

Northern Border has commitments of $3 million as of September 30, 2018 in connection with the meter station growth project, the compressor station overhaul project and other capital projects.

Summary of Great Lakes Contractual Obligations

Great Lakes contractual obligations related to debt as of September 30, 2018 included the following:

		Payments Due by Period (a)				
(unaudited) (millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Nine months Ended September 30, 2018
9.09% series Senior Notes due 2018 - 2021	40	10	20	10		9.09%(b)
6.95% series Senior Notes due 2019 - 2028	110	11	22	22	55	6.95%(b)
8.08% series Senior Notes due 2021 - 2030	100		10	20	70	8.08%(b)

250	21	52	52	125

(a) Represents 100 percent of Great Lakes debt obligations

(b) Fixed interest rate

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the senior note agreements, approximately $135 million of Great Lakes partners capital was restricted as to distributions as of September 30, 2018 (December 31, 2017 $139 million). Great Lakes was in compliance with all of its financial covenants at September 30, 2018.

Great Lakes has commitments of $3 million as of September 30, 2018 in connection with pipeline integrity program spending, major overhaul projects, and right of way renewals.

Summary of Iroquois Contractual Obligations

Iroquois contractual obligations related to debt as of September 30, 2018 included the following:

(unaudited) (millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Nine months Ended September 30, 2018
		Payments Due by Period (a)				
6.63% series Senior Notes due 2019	140	140				6.63%(b)
4.84% series Senior Notes due 2020	150		150			4.84%(b)
6.10% series Senior Notes due 2027	37	5	8	8	16	6.10%(b)
	327	145	158	8	16	

(a) Represents 100 percent of Iroquois debt obligations.

(b) Fixed interest rate

Iroquois has commitments of $2 million as of September 30, 2018 relative to procurement of materials on its expansion project.

Iroquois is restricted under the terms of its note purchase agreement from making cash distributions to its partners unless certain conditions are met. Before a distribution can be made, the debt/capitalization ratio must be below 75% and, the debt service coverage ratio must be at least 1.25 times for the four preceding quarters. At September 30, 2018, the debt/capitalization ratio was 48.1% and the debt service coverage ratio was 7.81 times, therefore, Iroquois was not restricted from making any cash distributions.

RELATED PARTY TRANSACTIONS

Please read Note 12 within Item 1. Financial Statements for information regarding related party transactions.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

The Partnership and our pipeline systems are exposed to market risk, counterparty credit risk, and liquidity risk. Our exposure to market risk discussed below includes forward-looking statements and is not necessarily indicative of actual results, which may not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual market conditions.

Our primary risk management objective is to mitigate the impact of these risks on earnings and cash flow, and ultimately, unitholder value. We do not use financial instruments for trading purposes.

We record derivative financial instruments on the balance sheet as assets and liabilities at fair value. We estimate the fair value of derivative financial instruments using available market information and appropriate valuation techniques. Changes in the fair value of derivative financial instruments are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. Qualifying derivative financial instruments gains and losses may offset the hedged items related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

MARKET RISK

From time to time, and in order to finance our business and that of our pipeline systems, the Partnership and our pipeline systems issue debt to invest in growth opportunities and provide for ongoing operations. The issuance of floating rate debt exposes the Partnership and our pipeline systems to market risk from changes in interest rates which affect earnings and the value of the financial instruments we hold.

Market risk is the risk that changes in market interest rates may result in fluctuations in the fair values or cash flows of financial instruments. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

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As of September 30, 2018, the Partnership s interest rate exposure resulted from our floating rate Senior Credit Facility, 2015 Term Loan Facility, GTN s Unsecured Term Loan Facility, PNGTS Revolving Credit Facility and Tuscarora s Unsecured Term Loan Facility, under which $308 million, or 14 percent, of our outstanding debt was subject to variability in LIBOR interest rates (December 31, 2017- $435 million or 18 percent). As of September 30, 2018, the variable interest rate exposure related to 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 3.26 percent.

If interest rates hypothetically increased (decreased) on these facilities by one percent (100 basis points), compared with rates in effect at September 30, 2018, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately $3 million.

As of September 30, 2018, $15 million, or 6 percent, of Northern Border s outstanding debt was at floating rates. If interest rates hypothetically increased (decreased) by one percent (100 basis points), compared with rates in effect at September 30, 2018, Northern Border s annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately nil.

GTN s Unsecured Senior Notes, Northern Border s and Iroquois Senior Notes, and all of Great Lakes Notes represent fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates. Interest rate risk does not apply to Bison and North Baja, as they currently do not have any debt.

The Partnership and our pipeline systems use derivatives as part of our overall risk management policy to assist in managing exposures to market risk resulting from these activities within established policies and procedures. Derivative contracts used to manage market risk generally consist of the following:

- Swaps contractual agreements between two parties to exchange streams of payments over time according to specified terms.
- Options contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period.

The Partnership s interest rate swaps are structured such that the cash flows of the derivative instruments match those of the variable rate of interest on the 2013 Term Loan Facility. From January 1 to June 30, 2018, the Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps at a weighted average fixed interest rate of 2.31 percent. Beginning July 1, 2018 and until its October 2, 2022 maturity, the 2013 Term Loan Facility was hedged using forward starting swaps at an average rate of 3.26 percent.

At September 30, 2018, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $17 million (both on a gross and net basis). At December 31, 2017, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $5 million (both gross and net basis). The change in fair value of interest rate derivative instruments recognized in other comprehensive income was a gain of $3 million and a gain of $12 million for the three and nine months ended September 30, 2018, respectively (2017 nil and gain of $1 million). During the three and nine months ended September 30, 2018, the amount reclassified from other comprehensive income to net income was a gain of $1 million and $4 million, respectively (2017 gain of $1 million and nil, respectively). For the three and nine months ended September 30, 2018, the net realized gain related to the interest rate swaps was nil and $2 million, respectively, and was included in financial charges and other (2017 - nil).

The Partnership has no master netting agreements; however, it has derivative contracts containing provisions with rights of offset. The Partnership has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. Had the Partnership elected to present these instruments on a net basis, there would be no effect on the consolidated balance sheet as of September 30, 2018 and December 31, 2017.

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with ASC 815, *Derivatives and Hedging*. PNGTS settled its position with a payment of $20.9 million to counterparties at the time of the refinancing and recorded the realized loss in accumulated other comprehensive income as of the termination date. The previously recorded loss was being amortized against earnings over the life of the PNGTS Senior Secured Notes. On May 10, 2018, PNGTS paid the remaining principal balance of its 2003 Senior Secured Notes using its available cash and as a result, our 61.71 percent proportionate share of the net unamortized loss on PNGTS included in other comprehensive income was amortized against earnings (December 31, 2017 - $1 million). For the three and nine months ended

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September 30, 2018, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was nil and $1 million (2017 nil and $1 million).

OTHER RISKS

Counterparty credit risk represents the financial loss that the Partnership and our pipeline systems would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Partnership or its pipeline systems. The Partnership and our pipeline systems have significant credit exposure to financial institutions as they provide committed credit lines and critical liquidity in the interest rate derivative market, as well as letters of credit to mitigate exposures to non-creditworthy customers. The Partnership closely monitors the creditworthiness of our counterparties, including financial institutions. However, we cannot predict to what extent our business would be impacted by uncertainty in energy commodity prices, including possible declines in our customers creditworthiness.

Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consists primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable as well as the fair value of derivative financial assets. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At September 30, 2018, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At September 30, 2018 Anadarko Energy Services Company owed us approximately $4 million which represented greater than 10 percent of our trade accounts receivable.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they become due. Our approach to managing liquidity risk is to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation.

At September 30, 2018, the Partnership had a Senior Credit Facility of $500 million maturing in 2021 and the outstanding balance on this facility was $60 million. In addition, PNGTS had a $125 million Revolving Credit Facility maturing in 2023 with $19 million drawn at September 30, 2018 and Northern Border had a committed revolving bank line of $200 million maturing in 2020 with $15 million drawn at September 30, 2018. The Senior Credit Facility, the Northern Border $200 million credit facility and the PNGTS $125 million credit facility all have accordion features for additional capacity of $500 million, $100 million and $50 million, respectively, subject to lender consent.

Item 4. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act) the management of our General Partner, including the principal executive officer and principal financial officer, evaluated as of the end of the period covered by this report the effectiveness of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures.

The Partnership s disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon and as of the date of the evaluation, the management of our General Partner, including the principal executive officer and principal financial officer, concluded that the Partnership s disclosure controls and procedures as of the end of the period covered by this quarterly report were effective to provide reasonable assurance that the information required to be disclosed by the Partnership in the reports that it files or submits under the Exchange Act, is (a) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and (b) accumulated and communicated to the management of our General Partner, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the quarter ended September 30, 2018, there was no change in the Partnership s internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

We are involved in various legal proceedings that arise in the ordinary course of business, as well as proceedings that we consider material under federal securities regulations. For additional information on other legal and environmental proceedings affecting the Partnership, please refer to Part 1 - Item 3 of the Partnership s Annual Report on Form 10-K for the year ended December 31, 2017.

Great Lakes v. Essar Steel Minnesota LLC, et al.

A description of this legal proceeding can be found in Note 16 within Item 1 Financial Statements of this Quarterly Report on Form 10-Q, and is incorporated herein by reference.

In addition to the above written matter, we and our pipeline systems are parties to lawsuits and governmental proceedings that arise in the ordinary course of our business.

Item 1A. Risk Factors

The following updated risk factors should be read in conjunction with the risk factors disclosed in Part I, Item 1A Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2017.

Our strategy of providing stable cash distributions on our common units by expanding our business may be significantly inhibited by the 2018 FERC Actions.

TransCanada has historically sold certain FERC-regulated assets to the Partnership, subject to TransCanada s funding needs and market conditions. Absent these dropdowns from TransCanada, our options for further growth could be significantly limited and there is uncertainty in whether we could be restored as a viable funding lever for TransCanada as a result of the 2018 FERC Actions. Also, market response to the 2018 FERC Actions has increased the relative cost of equity that the Partnership would incur to partially fund acquisitions or expansions in the future. Further deterioration of financial conditions combined with the current environment of rising interest rates could also raise the borrowing costs of the Partnership.

Following the 2018 GTN Settlement as described more fully under Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Quarterly Report on Form 10-Q, the estimated overall impact of the tax-related changes to our revenue and cash flow is currently estimated to be a reduction of approximately $20 to $30 million per year on an annualized basis beginning in 2019. This estimate could change due to numerous assumptions around the resolution of related issues as they are applied individually across our pipeline systems. If we cannot successfully finance and complete expansion projects or make and integrate acquisitions that are accretive or our assumptions about the impact of the tax-related change to our revenue and cashflows are incorrect, we may not be able to maintain historical levels of cash flow and distributions. For example, if we are unable to replace revenues from Bison once its contracts expire in January of 2021 or we are unable to replace cash flow that may be reduced through future rate proceedings, we could be required to take additional proactive measures, including further reductions in distributions from the current level of $0.65 per common unit, to facilitate repayments of debt as may be needed to maintain compliance with financial covenants, in addition to taking other significant strategic actions.

Rates and other terms of service for our pipeline systems are subject to approval and potential adjustment by FERC, which could limit their ability to recover all costs of capital and operations and negatively impact their rate of return, results of operations and cash available for distribution.

Our pipeline systems are subject to extensive regulation over virtually all aspects of their business, including the types and terms of services they may offer to their customers, construction of new facilities, creation, modification or abandonment of services or facilities, and the rates that they can charge to shippers. Under the Natural Gas Act, their rates must be just, reasonable and not unduly discriminatory. Actions by FERC, such as refusing to honor existing moratoria on rate changes, could adversely affect our pipeline systems ability to recover all of their current or future costs and could negatively impact their rate of return, results of operations and cash available for distribution.

Following the 2018 GTN Settlement as described more fully under Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Quarterly Report on Form 10-Q, our earnings, cash flows and financial position will be materially adversely impacted. Uncertainties still exist with respect to the variability of outcomes around the ultimate resolution of the issues arising from the 2018 FERC Actions as they are applied

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individually to the rest of our assets. The impact in 2018 is expected to be limited, while subsequent periods will be more significantly affected.

There is a risk however, that our assumptions around the potential outcomes of the 2018 FERC Actions could be incorrect such that cash available for distribution in the future would be lower than anticipated, which could necessitate further action beyond our immediate responses described under Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Quarterly Report on Form 10-Q.

Future events, such as the outcome of the 2018 FERC Actions, could negatively impact our estimates of fair value of our pipeline systems and equity investments, necessitating recognition of impairment.

We consider the carrying value of our assets, including goodwill and our equity method investments, whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments that we account for under the equity method, the impairment test requires us to consider whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary.

Our assumptions related to the estimated fair value of our remaining carrying value of each of our pipeline systems could be negatively impacted by near and long-term conditions including:

- future regulatory rate action or settlement,
- valuation of assets in future transactions,
- changes in customer demand for pipeline capacity and services,
- changes in North American natural gas production in the major producing basins,
- changes in natural gas prices and natural gas storage market conditions, and
- changes in other long-term strategic objectives.

There is a risk that adverse changes in these key assumptions as a result of the 2018 FERC Actions or other circumstances could result in future impairment of the carrying value of our pipeline systems.

The development of fair value estimates requires significant judgment including estimates of future cash flows, which are dependent on internal forecasts, estimates of the long-term rate of growth, estimates of the useful life over which cash flows will occur, and determination of the weighted average cost of capital.

We are currently monitoring developments following the Final Rule on the 2018 FERC Actions. Many of these elements will be revisited and we will incorporate results to date, future filings for the Partnership s assets and FERC responses to others in the industry into our annual goodwill impairment test as well as our routine review of property, plant and equipment and equity investments for recoverability. At this time we are unable to precisely calculate the impact on fair value, if any, to our assets. There is a risk that our pipeline assets could be negatively impacted by the 2018 FERC Actions once finalized or by other changes in management s estimates of fair value resulting in an impairment charge.

Chemical substances in the natural gas our pipeline systems transport could cause damage or affect the ability of our pipeline systems or third party equipment to function properly, which could result in increased preventative and corrective action costs.

GTN recently identified the presence of a chemical substance, dithiazine, at several facilities on the GTN system and those of some upstream and downstream connecting pipeline facilities. It has been determined that dithiazine drops out of gas streams in a powdery form at some points of pressure reduction (for example, at a regulator). In incidents where a sufficient quantity of the material accumulates in certain appurtenances, improper functioning of equipment occurs, which results in increased preventative and corrective action costs.

While we believe that the intermittent presence of dithiazine on our pipeline systems is from upstream sourced gas, we have advised stakeholders of potential risks, mitigation efforts and safety measures. With appropriate inspection and maintenance protocols, we do not believe there are any imminent material safety issues to people, equipment or the environment. Our pipeline systems, as well as other conduits of upstream sourced gas, are actively gathering information on the substance, seeking potential options to address the issue, and have informed federal and state regulators, trade associations, and other stakeholders of this information.

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We do not currently anticipate the cumulative cost of addressing this issue to be material, but there can be no assurance that significant costs will not be incurred in the future or that dithiazine or other substances will not be identified on our other pipeline systems.

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Item 6. **Exhibits**

Exhibits designated by an asterisk (*) are filed herewith and those designated with asterisks (**) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

2.1	Agreement for Purchase and Sale of Partnership Interest in Iroquois Gas Transmission System, L.P. by and between TCPL Northeast Ltd. and TransCanada Iroquois Ltd., as Sellers and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.1 to TC PipeLines, LP s Form 8-K filed May 3, 2017).
2.1.1	First Amendment to Purchase and Sale Agreement by and between TCPL Northeast Ltd. and TransCanada Iroquois Ltd., as Sellers and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 31, 2017 (Incorporated by reference from Exhibit 2.1.1 to TC PipeLines, LP s Form 10-Q filed August 3, 2017).
2.2	Option Agreement Relating to Partnership Interest in Iroquois Gas Transmission System, L.P. by and between TransCanada Iroquois Ltd. and TC Pipelines Intermediate Limited Partnership as dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.2 to TC PipeLines, LP s Form 8-K filed May 3, 2017).
2.3	Agreement for Purchase and Sale of Partnership Interest in Portland Natural Gas Transmission System, by and between TCPL Portland Inc., as Seller and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.3 to TC PipeLines, LP s Form 8-K filed May 3, 2017).
3.1	Third Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated April 1, 2015 (Incorporated by reference from Exhibit 3.1 to TC PipeLines, LP s Form 8-K filed April 1, 2015).
3.1.1	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated December 13, 2017 (incorporated by reference from Exhibit 3.1 to TC PipeLines, LP s Form 8-K filed December 15, 2017).
3.2	Certificate of Limited Partnership of TC PipeLines, LP (Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP s Form S-1 Registration Statement, filed on December 30, 1998).
31.1*	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Principal Financial Officer 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 Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 on this 9th day of November 2018.

TC PIPELINES, LP
(A Delaware Limited Partnership)
by its General Partner, TC PipeLines GP, Inc.

By:	/s/ Nathaniel A. Brown Nathaniel A. Brown President TC PipeLines GP, Inc. (Principal Executive Officer)
By:	/s/ William C. Morris William C. Morris Vice President and Treasurer TC PipeLines GP, Inc. (Principal Financial Officer)