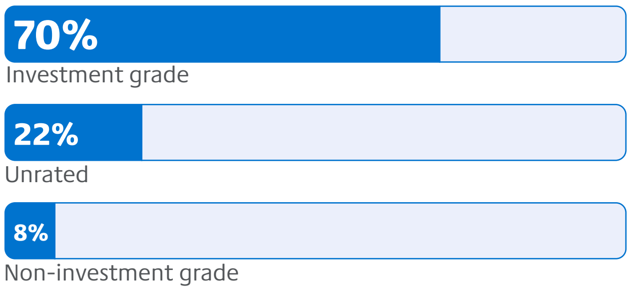
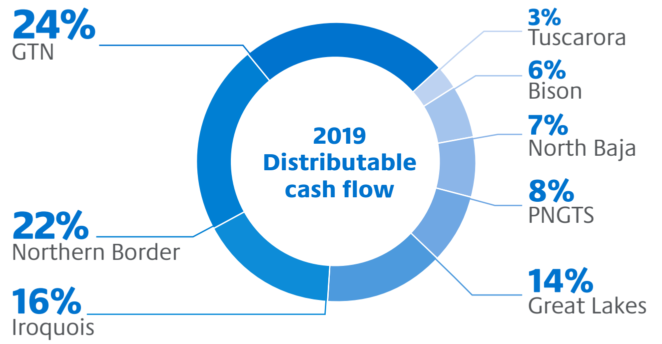
Annual report 2019

Financial highlights

Transportation customers by credit quality





Year Ended December 31 (millions of dollars, except unit amounts)	2019	2018	2017	2016	2015
Cash Flow					
Distributable cash flow [1]	340	391	310	313 [4]	290 [4]
Cash distributions paid	189	218	284	250	228
Class B Distributions paid	13	15	22	12	-
Income Statement					
Net income (loss) attributable to controlling interests	280	(182)	252	248 [4]	37 [4]
Adjusted earnings [1]	280	317	252	248 [4]	236 [4]
EBITDA [1]	460	27	445	433 [4]	223 [4]
Adjusted EBITDA [1]	460	526	445	433 [4]	422 [4]
Balance Sheet					
Total assets [2]	2,853	2,899	3,559	3,354 [4]	3,459 [4]
Long-term debt (including current maturities) [2]	2,012	2,118	2,415	1,920 [4]	1,980 [4]
Partners' equity	760	699	1,068	1,272 [4]	1,391 [4]
Common Unit Statistics (per unit)					
Cash distributions paid	2.60	2.95	3.88	3.66	3.46
Net income (loss) per common unit – basic and diluted	3.74	(2.68)	3.16	3.21	(0.03)
Adjusted earnings per common unit – basic and diluted [1]	3.74	4.18	3.16	3.21	3.03
Common Units Outstanding (millions)					
Units issued [3]	-	0.7	3.2	3.1	0.7
Weighted average for the year [3]	71.3	71.3	69.2	65.7	63.9
End of year [3]	71.3	71.3	70.6	67.4	64.3

(1) Distributable cash flow, EBITDA, adjusted EBITDA, adjusted earnings and adjusted earnings per common unit are non-GAAP measures. Non-GAAP measures do not have any standardized meaning prescribed by generally accepted accounting principles (GAAP). For more information on non-GAAP financial measures see item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K for the year ended December 31, 2019, filed with the Securities Exchange Commission (SEC).

(2) As a result of the application of ASU No. 2015-03 "Interest-Imputation of Interest" and similar to the presentation of debt discounts, debt issuance costs previously reported as other assets in the balance sheet were reclassified as an offset against their respective debt liabilities.

(3) In 2014, the Partnership launched its ATM program. Please read Note 11 – Partners' Equity in Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules".

(4) Recast information to consolidate PNGTS for all periods presented as a result of an additional 11.81 percent in PNGTS that was acquired from a subsidiary of TC Energy on June 1, 2017. Prior to this transaction, the Partnership owned a 49.9 percent interest in PNGTS that was acquired from TC Energy on January 1, 2016. Please read Note 2 – Significant Accounting Policies – Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules".

This material contains forward-looking statements relating to expectations, plans or prospects for TC PipeLines, LP. These statements are based upon the current expectations and beliefs of management and are subject to certain risks and uncertainties, including market conditions and other factors beyond the Partnership's control. Important factors that could cause actual results to differ materially from those described in the forward-looking statements herein are found in TC PipeLines, LP's Forms 10-K and 10-Q as filed with the SEC.

Nathan Brown,
President
TC PipeLines GP, Inc.

Message to unitholders

2019 was a solid, constructive year at TC PipeLines, LP. We worked hard to take full advantage of our existing natural gas infrastructure and to deliver disciplined capital projects. Following our FERC challenges in 2018, we identified sustainable, self-funded growth as our strategic focus going forward. Our goal is to achieve a healthy balance of distribution stability, strong financials and accretive capital investment opportunities. We're pleased with our progress in 2019 and we've entered 2020 with an enviable portfolio of highly contracted assets and significant momentum for growth.

Strong results

TC PipeLines finished 2019 in a very healthy financial position. Our commercial team succeeded in finding incremental transportation revenue opportunities across our portfolio, largely recouping the reduction in revenues that arose from the 2018 FERC Actions. Highlights include:

+ **$460 million in EBITDA realized**
+ **$340 million of distributable cash flow generated**
+ **Consistent cash distributions of $2.60 per common unit declared**
+ **$106 million in long-term debt repaid**
+ **Credit rating from Standard & Poor's upgraded to BBB/Stable**

Our accomplishments in 2019 translated into a 42 percent total unitholder return for investors. We believe that TC Pipelines' value proposition — a highly-contracted suite of natural gas infrastructure assets, low-risk business model, long track record of safe and reliable operations and sustainable growth — will deliver solid returns for our investors going forward.

Significant progress on organic growth in 2019

In November, we announced GTN XPress, our largest-ever project. This $335 million capital investment makes good economic sense – the multi-stage project reflects an optimal combination of horsepower replacement and reliability work coupled with new compression at existing sites to meet its customers' need for reliable and affordable transportation of clean-burning natural gas, consistent with the Pacific Northwest's desire for a cleaner energy future. Three quarters of this investment is expected to be placed into service and recovered in GTN's recourse rates commencing in 2022. The remaining investment is underpinned by 30-year fixed rate contracts and will increase GTN's firm transportation capacity by close to nine percent or 250,000 Dth/day, coming into service in November 2022 and 2023.

Visible growth continued at our Portland Natural Gas Transmission System where we are midway through two multi-phase compression-only projects fully backed by fixed rate 20+ year contracts. November 1 marked the in-service date of Phase II of Portland XPress and Phase I of Westbrook XPress, providing a reliable and affordable conduit for markets urgently in need of natural gas delivery service in New England and Canada's Maritime provinces. These efforts will double the firm delivery capacity of our asset to about 0.4 Bcf/day by 2022 while having a very minimal impact on neighboring landowners or the environment.

Finally, we recently announced a $13 million compression-only expansion project backed by a 20-year contract on Tuscarora that will increase the capability of that system by about seven percent.

Stable distributions and capital discipline

Our network of natural gas infrastructure is substantially long-term contracted and in high demand. We are pursuing accretive capital projects designed to provide stable cash distributions while maintaining the low-risk profile that TC PipeLines has stood for since its inception. We are confident our assets will support strong and stable distributions to our investors for the foreseeable future.

Looking forward, our focus is on maintaining a healthy balance sheet – over the past year we have de-levered to create the liquidity and financial capacity we need to fund our capital growth opportunities without issuing new equity. We value our investment-grade credit ratings, and guard them carefully. Our goal is to pursue disciplined growth opportunities across our asset footprint while maintaining a prudent annual distribution coverage of about 1.3 times and bank leverage metrics in the high 3 to low 4 times.

Bakken solutions

TC PipeLines continues to pursue opportunities to redeploy its Bison pipeline in response to the needs of producers in the prolific, transportation-capacity-constrained Bakken formation. We have received significant market interest in Bison's potential to have its direction of flow reversed, enabling it to deliver gas off Northern Border and on to existing third-party pipelines with links to the Cheyenne supply hub. We continue to work with prospective anchor shippers for this project, seeking to announce solutions for the Bakken's take-away needs within this calendar year.

Pursuing sustainable growth for a cleaner future

TC PipeLines is well positioned to capitalize on growing demand for innovative, lower-carbon solutions to meet America's energy needs, as evidenced by Iroquois' recently announced Expansion by Compression proposal. Designed to facilitate a rational and orderly transition to a renewable energy future and fully contracted for 20 years, this proposed project complements and supports New York State's environmental policy choices while at the same time addressing an urgent need for incremental natural gas transportation capacity into that region. Iroquois filed its FERC application in early February and is working through its regulatory review process. A decision as to whether this project will proceed is expected by early 2021.

We also announced our North Baja XPress project in 2019. This potential project responds to growing global demand for LNG as markets throughout the world transition to cleaner fuels. Still subject to our shipper's final investment decision by mid-2020, this 495,000 Dth/day compression-only capacity enhancement project will double the southbound capability of our North Baja system and is backed by a 20-year fixed rate contract.

These proposals support the shift from higher to lower emitting resources via compression-only solutions that maximize usage of existing systems. We will continue to pursue these and other responsible development opportunities in 2020. We believe this will drive our success going forward and will enable us to deliver long-term value to our investors.

Long-term value

Looking back over 2019, TC PipeLines has demonstrated that its sustainable natural gas infrastructure footprint, financial strength and careful management enable it to adapt to change and grow within the energy industry. As always, safe and reliable operations remain a constant focus for us as we are committed to maintaining TC Energy's industry-leading pipeline operations and safety practices. Our assets are well positioned to continue to deliver reliable, safe and environmentally responsible energy to markets that need and value our service and we are confident in TC PipeLines' ability to deliver unitholder value to you for decades to come.

Thank you for your continued investment.

Sincerely,

Nathan Brown
President, TC PipeLines GP, Inc.

Our strategy

Natural gas infrastructure is deeply interwoven into the U.S. economy – our industry touches nearly every other industry, and our success supports the success of many businesses, big and small. Natural gas and its associated infrastructure also complement renewables, and therefore are key to achieving national and global environmental aspirations. Here at TC PipeLines, our strategy is focused on generating long-term, steady and predictable distributions to our unitholders through long-life investments in critical infrastructure that provide safe and reliable delivery of clean-burning natural gas to our customers.

We are managed by our General Partner, which is wholly owned by TC Energy Corporation. For over 65 years, TC Energy has constructed, operated, maintained and modernized robust energy infrastructure networks across North America. Our GP operates our natural gas pipelines, apart from Iroquois' and PNGTS' joint facilities, which are owned together with third parties and operated by independent management.

In high demand

Natural gas is a major component of the power behind the plug that makes everything turn on, from appliances and electronics in homes, street and traffic lights in cities and computers that run the world. Natural gas demand continues to increase as electrical generation, industrial sectors and residential users seek increased use of cleaner-burning natural gas for their power, heating and cooling needs. Recent technological advances have made natural gas abundant, enabling the U.S. to become one of the world's largest natural gas exporters. North American natural gas production is expected to grow between now and 2040 to meet these needs, providing opportunities for the responsible growth of our infrastructure systems.

Organic growth

Our business model focuses on developing organic growth projects across our footprint that will enhance connections between North America's abundant natural gas supply and the premium markets that our assets already serve. We are actively pursuing opportunities that will deliver value for our unitholders through economic and efficient enhancements to our natural gas infrastructure systems, supported by long-term contracts.

We are executing compression-only expansion projects across our asset footprint to responsibly enhance and modernize our natural gas infrastructure and help build a cleaner energy future. In the West, our $335 million GTN XPress project is the largest organic opportunity in our history. It consists of horsepower replacement together with incremental compression capability at existing stations along its right-of-way. Tuscarora is proceeding with a compression-only project in response to demand in the region, demonstrating our commitment to maximizing the value of existing infrastructure. In the Northeast, our Portland XPress and Westbrook XPress projects are proceeding as planned and will nearly double capacity on this system by 2022.

And our efforts do not stop with these three successful projects – we are pursuing low-impact, compression-only projects across our suite of assets, including the Iroquois and North Baja systems, in response to customer demand.

Safe and reliable

Our natural gas infrastructure systems can transport about 10.9 Bcf/d or 13 percent of average daily U.S. natural gas demand. Our customers span the energy value chain and include large utilities, local distribution companies, major natural gas marketers and producers. These customers, and the markets they serve, depend on us to provide safe and reliable delivery of natural gas. We operate primarily in the Western U.S., the Midwest and the Northeast and have a strong market position in these regions.

GTN

GTN is our largest pipeline investment and provides a key service delivering natural gas from Western Canada and the Rocky Mountains to local utilities and power generation facilities in the Pacific Northwest, California and Nevada.

Northern Border

Northern Border is our next largest asset and provides a critical transportation route linking Canadian natural gas out of Western Canada, as well as U.S. gas out of the Bakken formation in North Dakota, with key markets in Minneapolis and the Chicago area.

Iroquois

Iroquois maintains key market connections into New York City, and serves regional LDCs and power plants in the Northeast.

Great Lakes

Our Great Lakes pipeline is utilized by the TC Energy Mainline and other shippers to provide service to natural gas producers seeking markets in the U.S. Midwest and central Canada. It is an important regional supplier of natural gas to local utilities in the upper Midwest and provides access to storage fields in Michigan and Southern Ontario which are vital to balancing supply and demand throughout the year as seasonal demands for natural gas fluctuate.

PNGTS, North Baja and Tuscarora are smaller in size but are critical infrastructure in their local markets. Although our Bison pipeline earns contractual revenue, it is not currently flowing gas due to changing natural gas basin dynamics in the Midwest and we are evaluating opportunities for this asset.

As operator of most of our assets, TC Energy is committed to industry-leading infrastructure operation and safety practices, a cornerstone for TC PipeLines over our 20-year history. Our pipelines are monitored 24/7/365 and our historical record of reliable operatorship is exemplary. We are focused on developing and operating our facilities safely, reliably and with minimal impact on the environment.

Highly contracted

Solid commercial and market fundamentals support our portfolio of natural gas pipeline assets. Most of our cash flows are derived from long-term contracts underpinned by high quality, creditworthy counterparties. Approximately 70 percent of our shippers are of investment grade status. And our contracts are structured such that shippers pay us for transportation capacity regardless of the quantity of gas they ship.

In the West, the majority of GTN's capacity is under long-term contracts with some maturing as late as 2045, Tuscarora is fully contracted through 2020, and North Baja's contracts mature between 2022 and 2031. In the Midwest, Northern Border is fully contracted with revenues substantially supported by long-term contracts with recent contract extensions typically for terms of up to five years. Great Lakes' contract tenor is lengthening as it remains a critical transportation link between natural gas storage fields in Michigan and Southern Ontario and major population centers in Minnesota, Wisconsin and Michigan in coordination with its TC Energy affiliate, ANR Pipeline. Great Lakes also provides a critical connection to the attractive Dawn market for gas producers in Western Canada. In the Northeast, PNGTS is effectively contracted through to 2032 and beyond. And Iroquois is highly contracted in the near term with contracts that expire out to 2026. Our Bison pipeline's capacity is contracted to approximately 40 percent until expiry in January of 2021.

Stable rates

Our response to the 2018 FERC actions has resolved uncertainty and restored stability in our business. The regulated rates on our pipelines will continue to afford cash flow certainty and underpin the stable nature of our asset portfolio.

Our pipeline systems operate under long-term FERC-approved rates. Our GTN pipeline is operating under a settlement with its shippers under which there is no requirement to file for new rates until 2022. Similarly, Great Lakes, Tuscarora and Northern Border have no requirement to file for new rates until 2022, 2023 and 2024, respectively. Iroquois also has no requirement to file for new rates until 2023. North Baja and PNGTS operate primarily under long-term negotiated rates and have no requirement to file for new rates.

Solid financial position

Our strong financial health is reflected in our investment-grade credit ratings from both Standard & Poor's and Moody's. Additionally, our lending group is strong and continues to be supportive.

Our assets continued to deliver value in 2019. Demand in the West remains strong, and natural gas producers in the WCSB are eager to access this premium market through our GTN and Tuscarora systems, leading to additional contracting. Northern Border continues to generate solid results as a very competitive transportation path out of Western Canada. Great Lakes remains a critical delivery infrastructure system in the upper Midwest market serving heating loads in the winter and providing access to substantial storage in the summer. The remainder of our assets performed well and in line with our expectations.

We generated $280 million in adjusted earnings and $340 million in distributable cash flow over the year. The 12 percent decrease in adjusted earnings year-over-year reflects the Bison contract terminations in fourth quarter 2018 and its resulting lower revenue in 2019. The rate decreases on our pipelines emanating from the 2018 FERC actions were largely offset by increased discretionary revenue from strong natural gas flows out of the WCSB and our robust contract position across our portfolio.

Disciplined and self-funded

> We are well positioned to capitalize on our growth opportunities. Debt repayments over the course of 2019 have further strengthened our balance sheet. Our growth projects will be funded through a combination of asset level debt and contributions from the partnership via cash from operations and draws under our revolving credit facility. No new equity issuances are anticipated – all growth will be self-funded. Our investment-grade credit ratings are indicative of our solid business platform and provide a firm basis from which to grow our business.

We see continued potential for organic expansion projects on our existing pipeline systems in our existing footprint. We continue to build a strong and diversified asset base of strategically located assets and believe that this strong foundation of reliable energy infrastructure will deliver unitholder value well into the future.

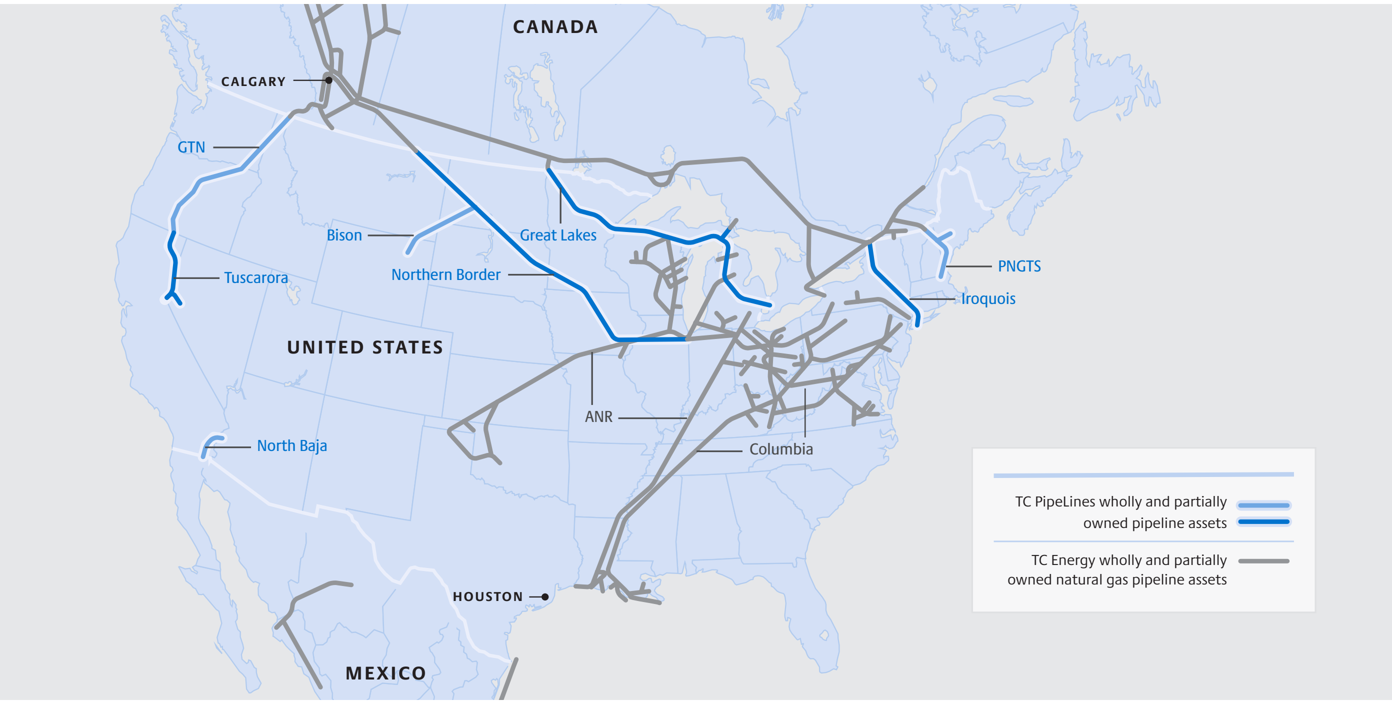


Table of contents

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

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," "estimate," "expect," "project," "intend," "plan," "believe," "forecast," "should," "predict," "could," "will," "may," and other terms and expressions of similar 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;
- potential changes in the taxation of master limited partnership (MLP) investments by state or federal governments such as elimination of pass-through taxation or tax deferred distributions;
- 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), 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, structure and closure of further potential acquisitions;
- potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner), TC Energy Corporation (TC Energy) and us;
- failure to comply with debt covenants, some of which are beyond our control;
- the ability to maintain secure operation of our information technology including management of cybersecurity threats, acts of terrorism and related distractions;

- the implementation of future accounting changes and ultimate outcome of commitments and contingent liabilities (if any);
- the impact of any impairment charges;
- changes in the political environment;
- operating hazards, casualty losses and other matters beyond our control;
- the overall increase in the allocated management and operational expenses to our pipeline systems for services performed by TC Energy; and
- the level of our indebtedness, including the indebtedness of our pipeline systems, changes in interest rates, and the availability of capital.

These and other risks are described in greater detail in Part I, Item 1A. "Risk Factors." Given these uncertainties, you should not place undue reliance on these forward-looking statements. All forward-looking 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.

Item 1. Business

NARRATIVE DESCRIPTION OF BUSINESS

GENERAL

We are a publicly traded Delaware master limited partnership. Our common units trade on the New York Stock Exchange (NYSE) under the symbol TCP. We were formed by TC Energy and its subsidiaries in 1998 to acquire, own and participate in the management of energy infrastructure businesses in North America. Our pipeline systems transport natural gas in the U.S.

We are managed by our General Partner, which is an indirect, wholly-owned subsidiary of TC Energy. At December 31, 2019, subsidiaries of TC Energy own approximately 24 percent of our common units, 100 percent of our Class B units, 100 percent of our incentive distribution rights (IDRs) and hold a two percent general partner interest in us. See Part II, Item 5. "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for more information regarding TC Energy's ownership in us.

RECENT BUSINESS DEVELOPMENTS

Growth Projects Update:

Below is a summary of our growth projects announced in 2019 and updates to previously announced projects:

PNGTS' Portland XPress Project — Our estimated $85 million Portland XPress Project or "PXP" was initiated in 2017 in order to expand deliverability on the PNGTS system to Dracut, Massachusetts through re-contracting and construction of incremental compression within PNGTS' existing footprint in Maine. PXP was designed to be phased in over a three-year time period. Phases I and II were placed into service on November 1, 2018 and November 1, 2019, respectively. Phase III of the project is expected to be in service on November 1, 2020. Beginning in 2021, PXP is expected to generate approximately $50 million in annual revenue for PNGTS. PNGTS filed the required applications with FERC for all three phases of the project in 2018, which included 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 natural gas supply to New England. The total final volume of the project is approximately 183,000 Dth/ day; 40,000 Dth/day from Phase I, 118,400 Dth/day from Phase II, which includes re-contracting and renewal of expiring contracts, and 24,600 Dth/day from Phase III. We continue to advance this project and have received all approvals on filings to date. We expect to file with FERC for approval to proceed with construction of Phase III of the project in early 2020. PXP is secured by long-term agreements and when all phases of the project are in service, PNGTS will be effectively fully contracted until 2032.

Additionally, in connection with PXP, PNGTS entered into an arrangement with TC Energy regarding the construction of certain facilities on the TC Energy system (TransQuebec and Maritimes Pipeline (TQM) and TC Energy's Canadian Mainline natural gas transmission system (Canadian Mainline)) that will be required to fulfill future PXP contracts on the PNGTS system. In the event the Canadian system expansions terminate prior to their in-service dates, PNGTS could be required to reimburse TC Energy for an amount up to the total outstanding costs incurred to the date of the termination. As a result of TC Energy's system expansions being commercially in service on November 1, 2019, and PNGTS' commitments on TC Energy's upstream pipelines being assigned to the PXP Phase II shippers, PNGTS' obligation to reimburse the costs for Phase I and II terminated, which was approximately $143 million at the time of termination. Going forward, in the event the Phase III expansion terminates prior to its in-service date, PNGTS will only be obligated to reimburse costs incurred by TC Energy in relation to Phase III, which was $0.6 million at December 31, 2019 and is estimated to be approximately $8.0 million by November 1, 2020, when TC Energy's facilities associated with the Phase III volumes go into service.

PNGTS' Westbrook XPress Project (Westbrook XPress) — Westbrook XPress is an estimated $125 million multi-phase expansion project that is expected to generate approximately $35 million in revenue for PNGTS on an annualized basis when fully in service. It is part of a coordinated offering to transport incremental Western Canadian Sedimentary Basin (WCSB) natural gas supplies to the Northeast U.S. and Atlantic Canada markets through additional compression capability at an existing PNGTS facility. Westbrook XPress is designed to be phased in over a four-year period which began on November 1, 2019 with Phase I. Phases II and III have estimated in-service dates of November 2021 and 2022, respectively. These three Phases will add incremental capacity of approximately 43,000 Dth/day, 69,000 Dth/day, and 18,000 Dth/day, respectively. Westbrook XPress, together with PXP, will increase PNGTS' capacity by 90 percent from 210,000 Dth/day to approximately 400,000 Dth/day. The Westbrook XPress contracts expire between 2036 and 2042.

GTN XPress Project (GTN XPress) — On November 1, 2019, we announced that GTN will move forward with the GTN XPress project which will transport approximately 250,000 Dth/day of additional volumes of natural gas enabled by TC Energy's system expansion upstream. The estimated total project cost of this integrated reliability and expansion project is $335 million. The project's reliability work is anticipated to be in service by the end of 2021 and will account for more than three quarters of the total project cost. These costs are expected to be recovered in recourse rates. The project's expansion work is anticipated to be commercially phased into service through November 2023. GTN XPress' expansion work is 100 percent underpinned by fixed rate negotiated contracts with an average term in excess of 30 years. The incremental capacity is expected to generate approximately $25 million in revenue annually when fully in service.

Tuscarora XPress Project (Tuscarora XPress) — Tuscarora XPress is an estimated $13 million expansion project through additional compression capability at an existing Tuscarora facility. Tuscarora XPress is 100 percent underpinned by a 20-year contract and will transport approximately 15,000 Dth/day of additional volumes when completed in November 2021. Tuscarora XPress is expected to generate approximately $2 million in revenue on an annualized basis when fully in service.

Iroquois Gas Transmission ExC Project (Iroquois ExC Project) — During the second quarter of 2019, Iroquois initiated the "Enhancement by Compression" project (ExC Project) which will optimize the Iroquois system to meet current and future gas supply needs of utility customers while minimizing the environmental impact through enhancements at existing compressor stations along the pipeline. In February 2020, Iroquois filed an application with FERC to authorize the construction of the project. The project's total design capacity is approximately 125,000 Dth/day with an estimated cost of $250 million and in-service date of November 2023. This project will be 100 percent underpinned with 20-year contracts.

North Baja XPress Project (North Baja XPress) — North Baja XPress is an estimated $90 million potential project to transport additional volumes of natural gas along North Baja's mainline system. The project was initiated in response to market demand to provide firm transportation service of up to approximately 495,000 Dth/day between Ehrenberg, Arizona and Ogilby, California. The binding open season for the project was concluded in April of 2019. In December 2019, North Baja filed an application with FERC to authorize the construction of this project. The estimated in-service date is November 1, 2022, subject to the satisfaction or waiver of certain conditions precedent, including a positive Final Investment Decision (FID) from Sempra LNG International, LLC.

PHMSA Compliance Regulation

On October 1, 2019, the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) released the first of three anticipated final rulemakings following its issuances in 2016 of an expansive proposed rulemaking (known as the "gas mega rule") revising the regulation of gas transmission and gathering lines. The October 1, 2019 final rule relates specifically to gas transmission pipelines and, among other things, updates reporting and records retention standards for covered pipelines and expands the level of required integrity assessments that must be completed on certain pipeline segments outside of high consequence areas (HCAs). The October 1, 2019 final rule also requires operators to review maximum allowable operating pressure records and perform specific remediation activities where records are not available. We are currently assessing the operational and financial impact related to this ruling which will become effective on July 1, 2020 with a 15-year implementation deadline. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020. See also Part I, Item 1. "Business — Government Regulation — Pipeline Safety Matters" for more information relating to PHSMA regulation of gas pipelines.

Cash Distributions to Common Units and our General Partner

Our quarterly declared cash distributions in 2019 remained the same as in 2018, which was $0.65 per common unit or $2.60 per common unit in total for the year. Please read Notes 15 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more information.

On April 23, 2019, the board of directors of our General Partner declared the Partnership's first quarter 2019 cash distribution in the amount of $0.65 per common unit, which was paid on May 13, 2019 to unitholders of record as of May 3, 2019. The declared distribution totaled $47 million and was paid 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 TC Energy as holder of 11,287,725 common units) and $1 million to our General Partner for its two percent general partner interest.

On July 23, 2019, the board of directors of our General Partner declared the Partnership's second quarter 2019 cash distribution in the amount of $0.65 per common unit, which was paid on August 14, 2019 to unitholders of record as of August 2, 2019. The declared distribution totaled $47 million and was paid 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 TC Energy as holder of 11,287,725 common units) and $1 million to our General Partner for its two percent general partner interest.

On October 22, 2019, the board of directors of our General Partner declared the Partnership's third quarter 2019 cash distribution in the amount of $0.65 per common unit, which was paid on November 14, 2019 to unitholders of record as of November 1, 2019. The declared distribution totaled $47 million and was paid 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 TC Energy as holder of 11,287,725 common units) and $1 million to our General Partner for its two percent general partner interest.

On January 21, 2020, the board of directors of the General Partner declared the Partnership's fourth quarter 2019 cash distribution in the amount of $0.65 per common unit, which was paid on February 14, 2020 to unitholders of record as of January 31, 2020. The declared distribution totaled $47 million and was paid 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 TC Energy as a holder of 11,287,725 common units) and $1 million to the General Partner for its two percent general partner interest.

Incentive distributions are paid to our General Partner if quarterly cash distributions on the common units exceed levels specified in the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (as amended, the Partnership Agreement). The distributions declared during 2019 did not reach the specified levels for any period and, therefore, the General Partner did not receive any distributions in respect of its IDRs in 2019. See Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cash Distribution Policy of the Partnership" for further information regarding the Partnership's distributions.

Class B Distributions

On January 21, 2020, the board of directors of our General Partner declared its annual Class B distribution in the amount of $8 million, which was paid on February 14, 2020. In 2019, the Class B distribution paid was $13 million. Please read Notes 11, 14 and 15 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more detailed disclosures on the Class B units.

Other Business Developments

Partnership structure — On December 31, 2018, the General Partner contributed its 1.0101 percent general partner interest in each of TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership (together, the Partnership ILPs) to TC PipeLines Intermediate GP, LLC (the Intermediate GP), a wholly-owned subsidiary of the Partnership, and received a one percent general partner interest in the Partnership in return (the ILP Contribution). This resulted in a simplification of the General Partner's effective two percent general interest in the Partnership previously held through its directly-held one percent and indirectly-held 1.0101 percent general partner interests in the Partnership and Partnership ILPs, respectively, to a directly-held two percent general partner interest in the Partnership. The Partnership subsequently held 100 percent of the Partnership ILPs' limited and general partner interests, with the general partner interest being held through the Intermediate GP.

During the fourth quarter of 2019, the Partnership initiated the dissolution of the Partnership ILPs and Intermediate GP. Effective October 31, 2019, the Intermediate GP and Partnership ILPs transferred 100 percent of the ownership of their pipeline assets to the Partnership, and the process of dissolving and unwinding the entities was completed in January 2020. Accordingly, the Partnership now owns its pipeline assets directly, which creates a more efficient partnership structure and aligns more closely with other MLP structures existing today, with no economic impact to the general and limited partners of the Partnership.

Financing

Partnership's 2013 $500 Million Term Loan Facility — In June 2019, the Partnership repaid $50 million of outstanding borrowings under its 2013 $500 million Term Loan Facility using the proceeds received from the Northern Border distribution on the same date. Additionally, the Partnership terminated an equivalent amount in interest rate swaps that were used to hedge this facility at a rate of 2.81%.

Partnership's Senior Credit Facility and Overall Debt Level — We continue to deleverage our balance sheet. At December 31, 2019, there was no outstanding balance under the Partnership's Senior Credit Facility. Additionally, the Partnership's overall consolidated debt was reduced by $106 million from $2,118 million at December 31, 2018 to $2,012 million at December 31, 2019 as a result of the (a) $40 million net repayment from cash flow of the outstanding balance under the Partnership's Senior Credit facility; (b) $50 million partial repayment of the Partnership's 2013 $500 Million Term Loan Facility; (c) the repayment of $35 million due upon the maturity of GTN's $75 million Unsecured Term Loan Facility; and (d) $1 million scheduled payment on Tuscarora's Unsecured Term Loan offset by $20 million of additional borrowings on PNGTS' revolving credit facility. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Result of Operations — Liquidity and Capital Resources" for more information.

Credit Rating Upgrade — On July 23, 2019, Standard & Poor's (S&P) upgraded the Partnership's credit rating to BBB/Stable from BBB−/Stable primarily due to the improvement in our financial risk profile resulting from our ongoing deleveraging efforts.

Financing — Unconsolidated Subsidiaries

Northern Border — In June 2019, Northern Border borrowed an additional $100 million under its $200 million revolving credit facility to finance a $100 million cash distribution, of which $50 million was received by the Partnership. Northern Border's outstanding balance under this facility amounted to $115 million at December 31, 2019.

Iroquois Financing — On May 9, 2019, Iroquois refinanced $140 million of 6.63% Senior Notes due 2019 and $150 million of 4.84% Senior Notes due in 2020 by issuing $140 million of new 15-year 4.12% Senior Notes and $150 million of new 10-year 4.07% Senior Notes. The debt covenants require Iroquois to maintain a debt to capitalization ratio below 75 percent and a debt service coverage ratio of at least 1.25 times for the four preceding quarters and are unchanged from those governing the refinanced Senior Notes.

Business Strategies

- Our strategy is focused on generating long-term, steady and predictable distributions to our unitholders by investing in long-life critical energy infrastructure that provides reliable delivery of energy to customers.
- Our investment approach is to develop or acquire assets that provide stable cash distributions and opportunities for new capital additions, while maintaining a low-risk profile. We are opportunistic and disciplined in our approach when identifying new investments.
- Our goal is to maximize distributable cash flows over the long term through efficient utilization of our pipeline systems and appropriate business strategies, while maintaining a commitment to safe and reliable operations.

Understanding the Natural Gas Infrastructure Business

Natural gas infrastructure moves natural gas from major sources of supply or upstream gathering facilities to downstream locations or markets that use natural gas to meet their energy needs. Infrastructure systems include meter stations that record how much natural gas comes on to the pipeline and how much exits at the delivery locations; compressor stations that act like pumps to move the large volumes of natural gas along the pipeline; and the pipelines themselves that transport natural gas under high pressure.

Regulation, rates and cost recovery

Interstate natural gas pipelines are regulated by FERC. FERC approves the construction of new facilities and regulates aspects of our business including the maximum rates that are allowed to be charged. Maximum rates are based on operating costs, which include allowances for operating and maintenance costs, income and property taxes, interest on debt, depreciation expense to recover invested capital and a return on the capital invested. During 2018, FERC issued a revised policy statement that changed its long-standing policy on the treatment of income taxes for rate-making purposes for MLP-owned pipelines. The revised policy statement had a significant impact on MLPs in general and on their respective natural gas pipeline assets. (See also Part I, Item 1. "Business — Government Regulation — 2018 FERC Actions for" more information).

Although FERC regulates maximum rates for services, interstate natural gas pipelines frequently face competition and therefore may choose to discount their services in order to compete.

Because FERC rate reviews are periodic and not annual, actual revenues and costs typically vary from those projected during a rate case. If revenues no longer provide a reasonable opportunity to recover costs, a pipeline can file with FERC for a determination of new rates, subject to any moratoriums in effect. FERC also has the authority to initiate a review to determine whether a pipeline's rates of return are just and reasonable. In some cases, a settlement or agreement with the pipeline's shippers is achieved, precluding the need for FERC to conduct a rate case, which may include mutually beneficial performance incentives. A settlement is ultimately subject to FERC approval.

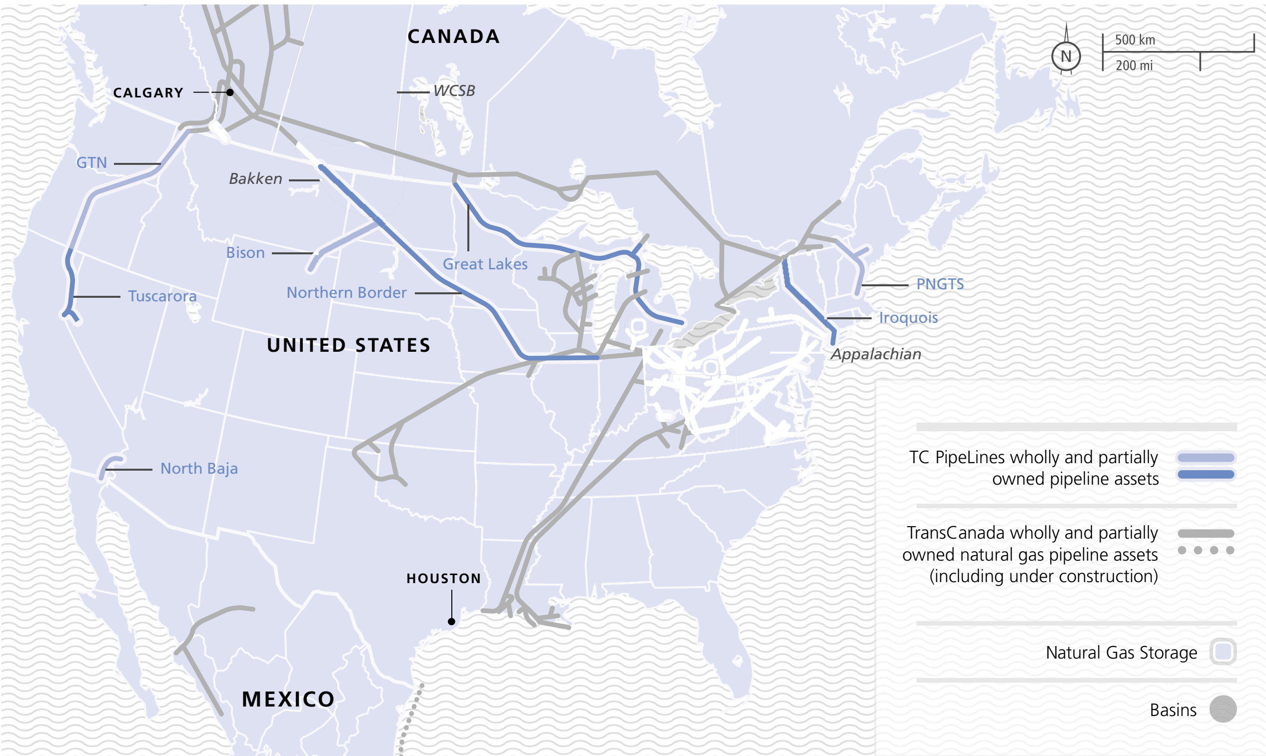
Contracting

New infrastructure projects are typically supported by long-term contracts. The term of the contracts is dependent on the individual developer's appetite for risk and is a function of expected rates of return, stability and certainty of returns. Transportation contracts expire at varying times and underpin varying amounts of capacity. As existing contracts approach their expiration dates, efforts are made to extend and/or renew the contracts. If market conditions are not favorable at the time of renewal, transportation capacity may remain uncontracted, be contracted at lower rates or be contracted on a shorter-term basis. Unsold capacity may be recontracted if and when market conditions become more favorable. The ability to extend and/or renew expiring contracts and the terms of such subsequent contracts will depend upon the overall commercial environment for natural gas transportation and consumption in the region in which the pipeline is situated.

Business environment

The North American natural gas infrastructure network has been developed to connect supply to market. Use and growth of the systems are affected by changes in the location, relative cost of natural gas supply and changing market demand.

The map below shows the location of certain North American basins in relation to our systems together with those of our General Partner and TC Energy.



Supply

Natural gas is primarily transported from producing regions and, in limited circumstances, from liquefied natural gas (LNG) import facilities to market hubs or interconnects for distribution to natural gas consumers. The ongoing development of shale and other unconventional gas reserves has resulted in increases in overall North American natural gas production and economically recoverable reserves.

There has been an increase in production from the development of shale gas reserves that are located close to traditional markets, particularly in the Northeastern U.S. This has increased the number of supply choices for natural gas consumers and has contributed to the decline of higher-cost sources of supply (such as certain offshore gas production from Atlantic Canada) resulting in changes to historical natural gas pipeline flow patterns.

The supply of natural gas in North America is expected to continue increasing over the next decade and over the long-term for a number of reasons, including the following:

- use of technology, including horizontal drilling in combination with multi-stage hydraulic fracturing, is allowing companies to access unconventional resources economically. This is increasing the technically accessible resource base of existing and emerging gas basins; and
- application of these technologies to existing oil fields where further recovery of the existing resource is now possible. There is often associated natural gas discovered in the exploration and production of liquids-rich hydrocarbons (for example the Bakken oil fields), which also contributes to an increase in the overall natural gas supply for North America.

Other factors that can influence the overall level of natural gas supply in North America include:

- the price of natural gas — low prices in North America may increase demand but reduce drilling activities that in turn diminish production levels, particularly in dry natural gas fields where the extra revenue generated from the associated liquids is not available. High natural gas prices may encourage higher drilling activities but may decrease the level of demand;
- producer portfolio diversification — large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of pipeline transportation services. Basin-on-basin competition impacts the extent and timing of a resource development that, in turn, drives changing dynamics for pipeline capacity demand; and
- regulatory and public scrutiny — changes in regulations that apply to natural gas production and consumption could impact the cost and pace of development of natural gas in North America.

Demand

The natural gas pipeline business ultimately depends on a shipper's demand for pipeline capacity and the price paid for that capacity. Demand for pipeline capacity is influenced by, among other things, supply and market competition, economic activity, weather conditions, natural gas pipeline and storage competition and the price of alternative fuels.

The growing supply of natural gas has resulted in relatively low natural gas prices in North America which has supported increased demand for natural gas particularly in the following areas:

- natural gas-fired power generation;
- petrochemical and industrial facilities;
- the production of the Marcellus, Alberta's oil sands, and the Bakken and shale deposits, although new greenfield projects that have not begun construction may be delayed in the current oil price environment;
- exports to Mexico to fuel electric power generation facilities; and
- exports from North America to global markets through a number of proposed LNG export facilities.

Commodity Prices

In general, the profitability of the natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and its price impact can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure.

Competition

Competition among natural gas pipelines is based primarily on transportation rates and proximity to natural gas supply areas and consuming markets. Changes in supply locations and regional demand have resulted in changes to pipeline flow dynamics. Where pipelines historically transported natural gas from one or two supply sources to their markets under long-term contracts, today many pipelines transport gas in multiple directions and under shorter contract terms. Some pipelines have even reversed their flows in order to adapt to changing sources of supply. Competition among pipelines to attract supply and new or existing markets to their systems has also increased across North America.

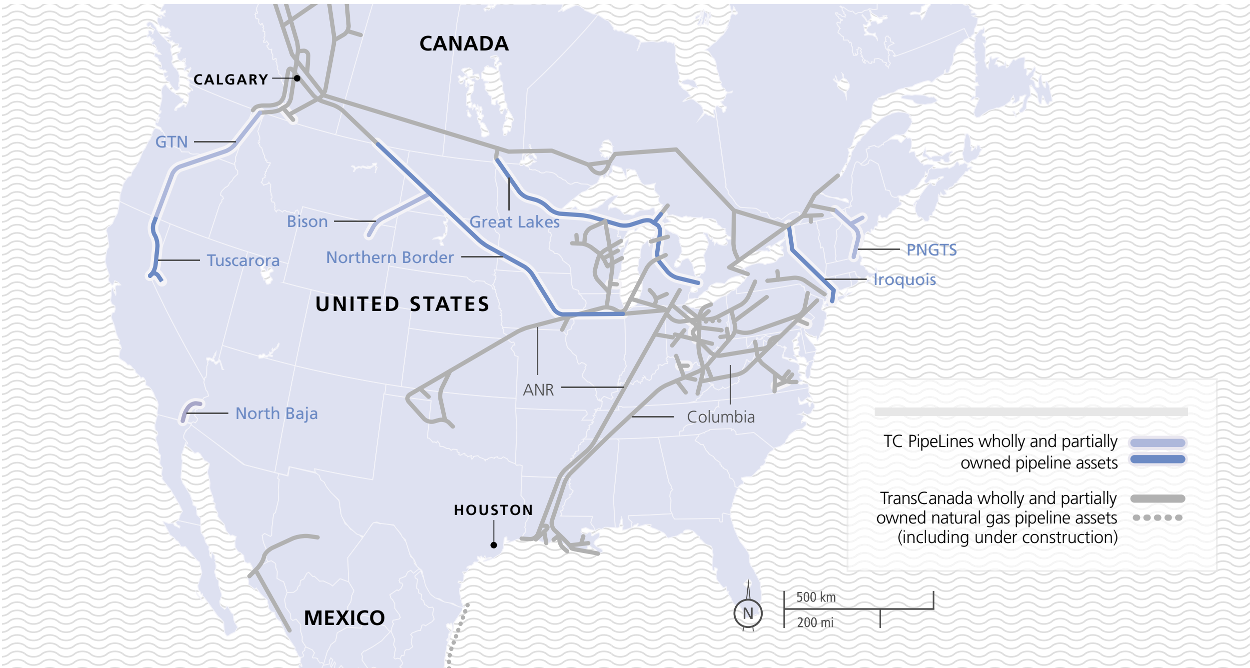
Our Natural Gas Infrastructure

We have ownership interests in eight natural gas interstate pipeline systems that are collectively designed to transport approximately 10.9 billion cubic feet per day of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western, Midwestern and Eastern U.S. All our pipeline systems, except Iroquois and the pipeline facilities jointly owned with MNE on PNGTS (Joint Facilities), are operated by subsidiaries of TC Energy. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Joint Facilities are operated by M&N Operating Company, LLC (MNOC), a subsidiary of Maritimes and Northeast Pipeline LLC (MNE). MNE is a subsidiary of Enbridge Inc.

Our pipeline systems include:

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends from an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100 percent
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can, but does not currently, transport natural gas from the Powder River Basin to Midwest markets.	100 percent
North Baja	86 miles	Extends from an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona to an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100 percent
Tuscarora	305 miles	Extends from the terminus of the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100 percent
Northern Border	1,412 miles	Extends from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Bakken, the Williston Basin and the Rocky Mountain area for deliveries to the Midwest. ONEOK Northern Border Pipeline Company Holdings LLC owns the remaining 50 percent of Northern Border.	50 percent
PNGTS	295 miles	Connects with the TQM pipeline at the Canadian border to deliver natural gas to customers in the U.S. northeast. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS. The 295-mile pipeline includes 107 miles of jointly owned pipeline facilities (the Joint Facilities) with MNE. The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32 percent of the Joint Facilities.	61.71 percent
Great Lakes	2,115 miles	Connects with the TC Energy Mainline at the Canadian border points near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TC Energy owns the remaining 53.55 percent of Great Lakes.	46.45 percent
Iroquois	416 miles	Extends from the TC Energy Mainline system near Waddington, New York to deliver natural gas to customers in the U.S. northeast. The remaining 50.66 percent is owned by: TC Energy (0.66 percent), Dominion Energy, Inc. (Dominion Energy) (50 percent)	49.34 percent

The map below shows the location of our pipeline systems.



Customers, Contracting and Demand

Our customers are generally large utilities, Local Distribution Companies (LDCs), major natural gas marketers, producing companies and other interstate pipelines, including affiliates. Our systems generate revenue by charging rates for transporting natural gas. Natural gas transportation service is provided pursuant to long-term and short-term contracts on a firm or interruptible basis. The majority of our pipeline systems' natural gas transportation services are provided through firm service transportation contracts with a reservation or demand charge that reserves pipeline capacity, regardless of use, for the term of the contract. The revenues associated with capacity reserved under firm service transportation contracts are not subject to fluctuations caused by changing supply and demand conditions, competition or customers. Customers with interruptible service transportation agreements may utilize available capacity after firm service transportation requests are satisfied.

Our pipeline systems actively market their available capacity and work closely with customers, including natural gas producers, LDCs, marketers and end users, to ensure our pipelines are offering attractive services and competitive rates. Approximately 70 percent of our long-term contract revenues are with customers who have an investment grade rating or who have provided guarantees from investment grade parties. We have obtained financial assurances as permitted by FERC and our tariffs for the remaining long-term contracts. See Part I, Item 1A. "Risk Factors."

Transactions with our major customers that are at least 10 percent of our consolidated revenues can be found under Note 17 — Transactions with major customers within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference. Additionally, our equity investee Great Lakes earns a significant portion of its revenue from TC Energy and its affiliates as disclosed under Note 18-Related party transactions within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

GTN — GTN's revenues are substantially supported by long-term contracts through the end of 2023 with its remaining contracts extending between 2024 and 2045. These contracts, which have historically been renewed on a long-term basis upon expiration, are primarily held by residential and commercial LDCs and power generators that use a diversified portfolio of transportation options to serve their long-term markets and marketers under a variety of contract terms. A small portion of our contract portfolio is contracted by industrial shippers and producers. We expect GTN to continue to be an important transportation component of these diversified portfolios. Incremental transportation opportunities are based on the difference in value between Western Canadian natural gas supplies and deliveries to Northern California.

In 2018, GTN benefitted from an increase in the quantity of natural gas it transports as debottlenecking activities occurred on upstream pipeline systems which deliver natural gas to GTN. These upstream activities are continuing and, as a result, we have signed over 700,000 Dth/day in long-term contracts starting between 2018 and 2020, of which 348,000 Dth/day resulted in additional quantity flowing onto GTN mid-2018, and 114,000 Dth/day in the fourth quarter of 2019. The remaining quantity is expected to begin to flow in mid-2020. The majority of these contracts have terms of at least 15 years.

On January 29, 2019, GTN's largest customer, Pacific Gas and Electric Company (Pacific Gas), filed for Chapter 11 bankruptcy protection. Pacific Gas accounted for approximately seven percent of the Partnership's consolidated revenues in 2019 (2018 — six percent). As a utility company, Pacific Gas serves residential and industrial customers in the state of California and has an ongoing obligation to serve its customers. We have not experienced collection issues in 2019 and we do not expect the bankruptcy of Pacific Gas to have a material impact on our future cash flows and results of operations.

During the fourth quarter of 2019, we announced the GTN XPress project, our largest organic opportunity in TCP's 20-year history. This project includes a horsepower replacement program and a brownfield expansion. The reliability work will enable increased firm natural gas transportation on GTN, which together with the growth component of the project, will sum to 250,000 Dth/d in additional long-term contracts on the pipeline system. See Part I, Item 1. "Business — Recent Business Developments — Growth Projects" for more information.

Northern Border — Northern Border is a highly competitive pipeline system with a weighted average remaining contract length of approximately 4 years. Northern Border contracts that include renewal rights and expiring contracts have typically been renewed for terms of five years. A significant portion of Northern Border's contract portfolio is contracted by utilities, marketers and industrial load. In addition, Northern Border sells seasonal transportation services which have traditionally been strongest during peak winter months to serve heating demand and peak spring/summer months to serve electric cooling demand and storage injection.

Great Lakes — Great Lakes' revenue is derived from both short-haul and long-haul transportation services. The majority of its contracts are with TC Energy and affiliates on multiple paths across its system. Great Lakes' ability to sell its available and future capacity will depend on future market conditions which are impacted by a number of factors including weather, levels of natural gas in storage, the capacity of upstream and downstream pipelines and the availability and pricing of natural gas supplies. Demand for Great Lakes' services has historically been highest in the summer to fill the natural gas storage complexes in Ontario and Michigan in advance of the upcoming winter season. During the winter, Great Lakes serves peak heating requirements for customers in Minnesota, Wisconsin, Michigan and the upper Midwest of the U.S.

A significant portion of Great Lakes' total contract portfolio is contracted by its affiliates including its long-term transportation agreement with TC Energy's Canadian Mainline that commenced on November 1, 2017 for a ten-year period that allows TC Energy to transport up to 0.711 billion cubic feet (equivalent to about 722,000 Dth/day) of natural gas per day on the Great Lakes system. This contract, which contains volume reduction options up to full contract quantity until November 1, 2020, was a direct benefit from TC Energy's long-term fixed price service on its Canadian Mainline that was launched in 2017. TC Energy's long-term fixed price service provides long-term capacity to TC Energy's shippers for the transportation of WCSB natural gas to markets in Eastern Canada and the U.S.

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 2021 to October 31, 2036 with a total contract value of approximately $1.3 billion on 0.9 billion of cubic feet (equivalent to about 913,000 Dth/day) capacity. The contracts contain reduction options (i) at any time on or before April 1, 2020 for any reason and (ii) any time before April 2021, if TC Energy is not able to secure the required regulatory approval related to anticipated expansion projects. During the first quarter of 2019, Great Lakes reached an agreement to amend a volume reduction "for any reason" option by extending the period "on or before" April 1, 2019 to "on or before" April 1, 2020. All the other terms remained the same.

PNGTS — PNGTS' revenues are primarily generated from transportation agreements with LDCs throughout New England and Canada's Atlantic provinces. The majority of PNGTS' current revenue stream is supported by long-term contracts entered into via a series of open seasons for long-term capacity held by PNGTS in recent years. Long-term contract commitments of approximately 82,000 Dth/day from PNGTS' Continent-to-Coast Contracts with several shippers for a term of 15 years (the C2C Contracts) open season began December 1, 2017, necessitating an increase in PNGTS' certificated capacity up to approximately 210,000 Dth/day. The C2C Contracts mature in 2032.

In addition to the C2C Contracts, in 2017, as a result of its PXP open season, PNGTS executed 20-year precedent agreements with several LDCs in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019 as well as expand the PNGTS system. PXP Phases I and II were placed into service on November 1, 2018 and November 1, 2019, respectively. Phase III of the project is expected to be in service on November 1, 2020. The total final volume of the project is approximately 183,000 Dth/ day: 40,000 Dth/day from Phase I, 118,400 Dth/day from Phase II, which includes re-contracting and renewal of expiring contracts, and 24,600 Dth/day from Phase III. PXP, together with the C2C expansion brings additional, natural gas supply options to markets in New England and Atlantic Canada in response to the growing need for natural gas transportation capacity in the region.

PXP is fully subscribed with no uncontracted firm capacity to meet incremental market demand in this region. In response, PNGTS developed a second expansion project. In early 2019, PNGTS announced the Westbrook XPress project which is an independent project that is designed to be phased in over a four-year period beginning November 1, 2019 with Phase I. Phases II and III have estimated in-service dates of November 2021 and 2022, respectively. Westbrook XPress will add incremental capacity of approximately 43,000 Dth/day, 69,000 Dth/day, and 18,000 Dth/day, respectively. Westbrook XPress, together with PXP, will increase PNGTS' capacity by 90 percent from 210,000 Dth/day to approximately 400,000 Dth/day. PNGTS signed precedent agreements for Phases II and III of Westbrook XPress, pending receipt of various regulatory and corporate approvals. The Westbrook XPress contracts expire between 2036 and 2042. See Part I, Item 1. "Business — Recent Business Developments — Growth Projects" for more information about PXP and Westbrook XPress.

Iroquois — Iroquois transports natural gas under long-term contracts that expire between 2019 and 2026 and extends from TC Energy's Canadian Mainline system at the U.S. border near Waddington, New York to markets in the U.S. northeast, including New York City, Long Island and Connecticut. Iroquois provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, directly or indirectly, through interconnecting pipelines and exchanges throughout the northeastern U.S. Iroquois also earns discretionary transportation service revenues which can have a significant earnings impact. Discretionary transportation service revenues include short-term firm transportation service contracts with less than one-year terms as well as standard interruptible transportation service contracts. In 2019, Iroquois earned approximately 12 percent of its revenues from discretionary services.

During the second quarter of 2019, Iroquois initiated the ExC Project to meet current and future gas supply needs of utility customers by upgrading its compressor stations along the pipeline. This project will be 100 percent underpinned with 20-year contracts and is subject to necessary permits and approvals. This project has an estimated in-service date of November 2023. See Part I, Item 1. "Business — Recent Business Developments — Growth Projects" for more information.

North Baja — The North Baja pipeline system is an 86-mile bi-directional natural gas pipeline transporting gas between Arizona, California and the Mexican border since 2002. North Baja's historical steady financial performance is due to its strong contracting levels, having a weighted average remaining firm contract length of about 7 years. North Baja currently has a design capacity of 500 mcf/d of southbound transportation and is capable of transporting 600 mcf/d in a northbound direction.

In April 2019, we concluded a successful binding open season for North Baja XPress project to transport additional volumes of natural gas along North Baja's mainline system between Arizona and California. The estimated in-service date of the project is November 2022, subject to the satisfaction or waiver of certain conditions precedent including positive

FID from Sempra LNG International, LLC. See Part I, Item 1. “Business — Recent Business Developments — Growth Projects” for more information.

Bison — As previously disclosed, natural gas is not flowing on the Bison system in response to the recent relative cost advantage of WCSB and Bakken sourced gas versus Rockies production. From its in-service date in 2011 up to the fourth quarter of 2018, Bison was fully contracted on a ship-or-pay basis. During the fourth quarter of 2018, through a Permanent Capacity Release Agreement, Tenaska Marketing Ventures (Tenaska) assumed Anadarko Energy Services Company’s (Anadarko) ship-or-pay contract obligation on Bison, the largest contract on Bison. After assuming the transportation obligation, Bison accepted an offer from Tenaska to terminate this contract. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison. At the completion of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018.

The two customers represented approximately 60 percent of Bison’s revenue and accordingly, in 2019, Bison’s revenue was reduced by approximately $47 million. Its remaining contracts in the system expire in January 2021. Bison will therefore be approximately 40 percent contracted on a ship-or-pay basis in 2020 and is expected to generate approximately $30 million in revenue, similar to 2019.

Based on this development and other qualitative factors, the Partnership evaluated the remaining carrying value of Bison’s property, plant and equipment at December 31, 2018 and concluded that the entire amount was no longer recoverable, resulting in a non-cash impairment charge during the fourth quarter of 2018. We continue to explore alternative transportation-related options for Bison and we believe commercial potential exists to reverse the direction of natural gas flow on Bison for deliveries onto third party pipelines and ultimately connect into the Cheyenne hub. See also Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates” for more information.

Tuscarora — Tuscarora’s revenues are substantially supported by long-term contracts with a weighted average remaining contract length of approximately 5 years. We expect Tuscarora to continue be fully contracted on a long-term basis when its current contracts expire.

During the fourth quarter of 2019, we announced that we are proceeding with the Tuscarora XPress project, an expansion project through additional compression capability at an existing Tuscarora facility that is expected to increase capacity by approximately 7 percent by November 2021. Tuscarora XPress is 100 percent underpinned by a 20-year contract. See Part I, Item 1. “Business — Recent Business Developments — Growth Projects” for more information.

Competition

Overall, our pipeline systems generate a substantial portion of their cash flow from long-term firm contracts for transportation services and are therefore insulated from competitive factors during the terms of the contracts. If these long-term contracts are not renewed at their expiration, our pipeline systems face competitive pressures which influence contract renewals and rates charged for transportation services.

GTN and Northern Border, through their respective connections with TC Energy’s Foothills systems, and Great Lakes and Iroquois, through their respective connections with TC Energy’s Canadian Mainline, compete with each other for WCSB natural gas supply as well as with other pipelines, including the Alliance pipeline and the Westcoast pipeline. Northern Border and Great Lakes compete in their respective market areas for natural gas supplies from other basins as well, such as the Bakken, Rocky Mountain area, Mid-Continent, Gulf Coast, Utica and Marcellus basins. GTN primarily competes with pipelines supplying natural gas into California and Pacific Northwest markets.

Bison competes for deliveries with other pipelines that transport natural gas supplies within and away from the Rocky Mountain area, and gas from the Rocky Mountains that is delivered into the Midwest must compete with gas sourced from the Bakken and Western Canada.

North Baja’s southbound pipeline capacity competes with deliveries of LNG received at the Costa Azul terminal in Mexico. If LNG shipments are received at Costa Azul, North Baja’s northbound capacity competes with pipelines that deliver Rocky Mountain area, Permian and San Juan basin natural gas into the southern California area.

Tuscarora competes for deliveries primarily into the northern Nevada natural gas market with natural gas from the Rocky Mountain area.

PNGTS connects with the TQM pipeline at the Canadian border and shares facilities with the MNE from Westbrook, Maine to a connection with the Tennessee Gas Pipeline System near Boston, Massachusetts. PNGTS competes with LNG supplies and gas flows from Canada and with LNG delivered into Boston. Tennessee Gas Pipeline and Algonquin Gas Transmission also compete with PNGTS for gas deliveries into New England markets.

As noted above, Iroquois, through its connection with TC Energy's Canadian Mainline System, competes for WCSB natural gas supply with other pipelines. Iroquois connects at five locations with three interstate pipelines (Tennessee Gas, CNG Gas Transmission and Algonquin Gas Transmission) and TC Energy's Canadian Mainline System near Waddington, New York and provides a link between WCSB natural gas deliveries to markets in the states of Connecticut, Massachusetts, New Hampshire, New Jersey, New York, and Rhode Island.

Additionally, our pipeline assets face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our pipeline systems' investment hurdles or projects that proceed with lower overall financial returns.

Relationship with TC Energy

TC Energy is the indirect parent of our General Partner and at December 31, 2019, owns, through its subsidiaries, approximately 24 percent of our common units, 100 percent of our Class B units, 100 percent of our IDRs and has a two percent general partner interest in us. TC Energy is a major energy infrastructure company, listed on the Toronto Stock Exchange and NYSE, with more than 65 years of experience in the responsible development and reliable operation of energy infrastructure in North America. TC Energy's business is primarily focused on natural gas and liquids transmission and power generation services, delivering the energy millions of people rely on to power their lives in a sustainable way. TC Energy consists of investments in 57,900 miles of natural gas pipelines, approximately 3,000 miles of liquids pipelines and 653 billion cubic feet of natural gas storage capacity. TC Energy also owns or has interests in approximately 6,000 megawatts of power generation. TC Energy operates most of our pipeline systems and, in some cases, contracts for pipeline capacity.

See also Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information on our relationship with TC Energy.

Government Regulation

Federal Energy Regulatory Commission

All of our pipeline systems are regulated by FERC under the Natural Gas Act of 1938 (NGA) and Energy Policy Act of 2005, which gives FERC jurisdiction to regulate effectively all aspects of our business, including:

- transportation of natural gas in interstate commerce;
- rates and charges;
- terms of service and service contracts with customers, including counterparty credit support requirements;
- certification and construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- standards of conduct for business relations with certain affiliates.

Our pipeline systems' operating revenues are determined based on rate options stated in our tariffs which are approved by FERC. Tariffs specify the general terms and conditions for pipeline transportation service including the rates that may be charged. FERC, either through hearing a rate case or as a result of approving a negotiated rate settlement, approves the maximum rates permissible for transportation service on a pipeline system which are designed to recover the pipeline's cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set, a pipeline system is not permitted to adjust the maximum rates to reflect changes in costs or contract demand until new rates are approved by FERC. Pipelines are permitted to charge rates lower than the maximum tariff rates in order to compete. As a result, earnings and cash flows of each pipeline system depend on a number of factors including costs incurred, contracted capacity and transportation path, the volume of natural gas transported, and rates charged.

2018 FERC Actions

Background:

During the latter part of 2018, the Partnership completed its regulatory filings to address the issues contemplated by Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act (2017 Tax Act) and certain FERC actions that began in March of 2018, namely FERC's Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that 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 quantified 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 (collectively, the 2018 FERC Actions).

Pipelines filing FERC Form No. 501-G had 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 guaranteed a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G showed the pipeline's estimated return on equity (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 Accumulated Deferred Income Tax (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 believed that using the limited Section 4 option would not result in just and reasonable rates. If the pipeline committed to file by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it did not believe the pipeline's rates must change; or
- Option 4: take no action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that had not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

Impact of the 2018 FERC Actions to the Partnership:

The 2018 FERC Actions directly addressed two components of our pipeline systems' cost-of-service based rates: the allowance for income taxes and the inclusion of ADIT in their rate base. 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, such as those partially owned by corporations including Great Lakes, Northern Border, Iroquois and PNGTS. Additionally, any FERC-mandated rate reduction did not affect negotiated rate contracts.

Prior to the 2018 FERC Actions, none of the Partnership's pipeline systems had a requirement to file or adjust their rates earlier than 2022 as a result of their existing rate settlements. However, several of our pipeline systems accelerated such adjustments as a result of the 2018 FERC Actions. The actions taken by our pipelines are outlined below:

	Form 501-G Filing Option	Impact on Maximum Rates	Moratorium, Mandatory Filing Requirements and Other Considerations
Great Lakes	Option 1; reflected an elimination of income tax allowance and ADIT; Limited Section 4 accepted by FERC; 501-G Docket remains open	2.0% rate reduction effective February 1, 2019	No moratorium in effect; comeback provision with new rates to be effective by October 1, 2022
GTN	Settlement approved by FERC on November 30, 2018 eliminated the requirement to file Form 501-G	A refund of $10 million to its firm customers in 2018; 10.0% rate reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021; these reductions will replace the 8.3% rate reduction in 2020 agreed to as part of the last settlement in 2015	Moratorium on rate changes until December 31, 2021; comeback provision with new rates to be effective by January 1, 2022; Settlement agreement reflected an elimination of income tax allowance and ADIT
Northern Border	Option 1; reflected an elimination of income tax allowance and ADIT; subsequent settlement approved by FERC on May 24, 2019; 501-G docket closed	2.0% rate reduction effective February 1, 2019 to December 31, 2019 extended until July 1, 2024 unless superseded by a subsequent rate case or settlement	No moratorium in effect; comeback provision with new rates to be effective by July 1, 2024
Bison	Option 3; reflected an elimination of income tax allowance and ADIT; accepted by FERC; 501-G docket closed	No rate changes proposed	No moratorium or comeback provisions
Iroquois	Option 3; reflected an elimination of income tax allowance and ADIT; subsequent settlement approved by FERC on May 2, 2019; 501-G docket closed	3.25% rate reduction effective March 1, 2019; additional 3.25% rate reduction effective April 1, 2020	Moratorium on rate changes until September 1, 2020; comeback provision with new rates to be effective by March 1, 2023
PNGTS	Option 3; reflected an elimination of income tax allowance and ADIT; accepted by FERC; 501-G docket closed	No rate changes	No moratorium or comeback provisions
North Baja	Option 1; reflected an elimination of income tax allowance and ADIT; accepted by FERC; 501-G docket closed	10.8% rate reduction effective December 1, 2018	No moratorium or comeback provisions; approximately 90 percent of North Baja's contracts are negotiated; 10.8% reduction is on maximum rate contracts only
Tuscarora	Option 1; reflected an elimination of income tax allowance and ADIT; subsequent settlement approved by FERC on May 2, 2019; 501-G docket closed	1.7% rate reduction effective February 1, 2019; additional rate reduction of 10.8% effective August 1, 2019	Moratorium on rate changes until January 31, 2023; comeback provision with new rates to be effective by February 1, 2023; Settlement agreement reflected an elimination of income tax allowance and ADIT

The Final Rule allowed pipelines owned by MLPs and other pass through entities to remove the ADIT liability from their rate bases, and thus increase the net recoverable rate base, partially or in some cases wholly mitigated the loss of the tax allowance in cost-of-service based rates. Following the elimination of the tax allowance and the ADIT liability from rate base, rate settlements and related filings of all pipelines held wholly or in part by the Partnership summarized above, the estimated impact of the tax-related changes to our revenue and cash flow is a reduction of approximately $30 million per year on an annualized basis beginning in 2019.

In 2019, the estimated impact of the tax-related changes to our revenue and cashflow have been largely mitigated by additional revenue generated from continued strong natural gas flows mainly out of WCSB and from solid contracting levels across the Partnership pipeline assets. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information.

Filings required by the Final Rule and Rate Settlements:

GTN

On October 16, 2018, GTN filed an uncontested settlement with FERC to address the changes proposed by the 2018 FERC Actions on its rates via an amendment to its prior 2015 settlement (the 2018 GTN Settlement). The 2018 GTN Settlement reflects an elimination of the tax allowance previously recovered in rates along with ADIT for rate-making purposes (see details of the 2018 GTN Settlement in the table above).

Tuscarora

On December 6, 2018, Tuscarora elected to make a limited NGA Section 4 filing to reduce its maximum rates by approximately 1.7 percent and eliminate its deferred income tax balances previously used for rate setting (Option 1). On March 15, 2019, Tuscarora filed an uncontested settlement with FERC to address the issues contemplated by the 2017 Tax Act and 2018 FERC Actions via an amendment to its prior 2016 settlement (the 2019 Tuscarora Settlement).

Among the terms of the 2019 Tuscarora Settlement, Tuscarora agreed to reduce its existing maximum system rates by 1.7 percent effective February 1, 2019 through to July 31, 2019, followed by an additional decrease of 10.8 percent for the period August 1, 2019 through the term of the settlement. Tuscarora is required to have new rates in effect on February 1, 2023. Tuscarora and its customers also agreed on a moratorium on rate changes until January 31, 2023. The 2019 Tuscarora Settlement, which was approved by FERC on May 2, 2019, will also reflect an elimination of the tax allowance previously recovered in rates along with ADIT for rate-making purposes.

Iroquois

On December 6, 2018, Iroquois submitted its FERC Form No. 501-G in response to the FERC Final Rule along with an explanation as to why rate changes were not required. On February 28, 2019, Iroquois filed an uncontested settlement with FERC to address the issues contemplated by the 2017 Tax Act and 2018 FERC Actions via an amendment to its prior 2016 settlement (the 2019 Iroquois Settlement). Among the terms of the 2019 Iroquois Settlement, Iroquois agreed to reduce its existing maximum system rates by 6.5 percent to be implemented in two phases, (i) effective March 1, 2019, a 3.25 percent rate reduction and (ii) effective April 1, 2020, an additional 3.25 percent rate reduction, which will conclude the total 6.5 percent rate reduction from the 2016 settlement rates. The 2019 Iroquois Settlement, which was approved by FERC on May 2, 2019, preserved the 2016 settlement moratorium on further rate changes until September 1, 2020. Unless superseded by a subsequent rate case or settlement, Iroquois will be required to have new rates in effect by March 1, 2023.

Existing Settlements with subsequent limited section 4 rate reductions

Great Lakes — Great Lakes operates under a settlement approved by FERC effective January 1, 2018 (the 2017 Great Lakes Settlement). The 2017 Great Lakes Settlement did not contain a moratorium and eliminated its revenue sharing mechanism with customers. Great Lakes is required to file new rates effective October 1, 2022. Effective February 1, 2019, FERC approved an additional 2 percent rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to Great Lakes' limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and mitigated the loss of Great Lakes' tax allowance.

Northern Border — Northern Border operates under a settlement approved by FERC effective January 1, 2018 (the 2017 Northern Border Settlement). The 2017 Northern Border Settlement provided for tiered rate reductions from January 1, 2018 to December 31, 2019 that equate to an overall rate reduction of 12.5 percent when compared to 2017 rates by January 1, 2020 (10.5 percent by December 31, 2019 and additional two percent by January 1, 2020). The 2017 Northern Border Settlement did not contain a moratorium and Northern Border is required to file new rates effective July 1, 2024. Effective February 1, 2019, FERC approved an additional two percent rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to Northern Border's limited NGA Section 4 filing. On April 4, 2019, Northern Border filed an amended settlement agreement that extended the two percent rate reduction implemented on February 1, 2019 to July 1, 2024 effective January 1, 2020 unless superseded by a subsequent rate case or settlement. On May 24, 2019, FERC approved the amended settlement agreement and Northern Border's 501-G proceeding was terminated. The removal of ADIT increased net recoverable rate base and mitigated the loss of Northern Border's tax allowance.

Bison — Bison operates under the rates approved by FERC in connection with Bison's initial construction and has no requirement to file a new rate proceeding.

North Baja — North Baja operates under the rates approved by FERC in its original certificate proceeding in 2001 and has no requirement to file a new rate proceeding. Effective December 1, 2019, FERC approved a 10.8 percent rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to North Baja's limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and partially mitigated the loss of North Baja's tax allowance.

PNGTS — PNGTS operates under the rates approved by FERC in PNGTS' most recent rate proceeding, effective December 1, 2010. PNGTS has no requirement to file a new rate proceeding.

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 changes in this policy to affect us in a materially different manner than other similarly sized natural gas pipeline companies operating in the United States.

Environmental Matters

Our assets are subject to a variety of stringent U.S. federal, tribal, state and local environmental laws and regulations relating to air quality, biodiversity, wastewater discharges, waste management, water management, and water quality. These laws and regulations generally require natural gas pipeline companies to obtain and comply with a variety of environmental registrations, licenses, permits and other authorizations required for construction and operations. Consequences of noncompliance with these laws, regulations, or authorizations include, but are not limited to, the following: administrative, civil, and/or criminal penalties; imposition of investigatory, remedial, and/or corrective actions; delay in obtaining necessary authorizations; denial or termination of project authorizations; imposition of restrictions or limitations on project authorizations; addition or removal of conditions or terms in project authorizations; and/or the issuance of orders limiting or prohibiting operations or construction. Violations of certain environmental laws and regulations can result in the imposition of strict, joint and several liability.

Federal Environmental Laws and Regulations

Federal environmental laws, and their related regulations, that most significantly impact our pipeline operations include:

- *the Clean Air Act (CAA),* which regulates air pollution on a national level by restricting the emission of air pollutants from various stationary and mobile sources and imposes an array of pre-construction, operational, monitoring, and reporting requirements. The CAA authorizes the EPA to adopt climate change regulatory initiatives relating to greenhouse gas (GHG) emissions;

- *the Federal Water Pollution Control Act,* also known as the Clean Water Act (CWA), which regulates discharges of pollutants into state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected "Waters of the United States" (WOTUS);
- *the Oil Pollution Act of 1990 (OPA),* which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in WOTUS;
- *the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA),* which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- *the Resource Conservation and Recovery Act (RCRA),* which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- *the Toxic Substances Control Act (TSCA),* which governs the production, importation, use and disposal of specific chemicals and provides the EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and mixtures, including polychlorinated biphenyls (PCBs), asbestos, radon, and lead-based paint;
- *the Emergency Planning and Community Right-to-Know Act (EPCRA),* which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories;
- *the Endangered Species Act (ESA),* which restricts activities that may affect federally identified endangered and threatened species or their habitats by the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas; and
- the National Environmental Policy Act (NEPA), which requires federal agencies to evaluate the environmental effects of major agency actions and prepare environmental assessments (EAs) or more detailed environmental impact statements (EISs) that may be made available for public review and comment.

Regional, State, Tribal, and Local Environmental Laws and Regulations

In addition to the numerous environmental laws and regulations at the federal level, there are also regional, state, tribal, and local environmental laws and regulations that sometimes make permitting, development, or expansion of certain projects more extensive and complex. For example, some of our projects may require the acquisition of permits from more than one level of government. Additionally, regional, state, tribal, or local laws and regulations may be more stringent than their federal counterparts. The existence of environmental laws at various levels of government also provide more opportunities for citizens' suits or other forms of opposition to new developmental projects or the expansion of existing projects. These factors all have the potential to substantially restrict or delay project permitting, development, or expansion of projects and increase costs to the Partnership in the process. See Risk Factors under Part I, Item 1A of this Form 10-K for further discussion on environmental laws and regulations, including with respect to climate change, including methane and other GHG emissions, ozone standards, site remediation; and other regulations relating to environmental protection.

Total Financial Impact of Compliance with Environmental Laws and Regulations

At this time, the ultimate financial impact of complying with U.S. environmental laws and regulations is indeterminable. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any regulatory violations, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated facilities, and with damage claims arising from the contamination. The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because (1) interpretation and enforcement of environmental laws and regulations are constantly changing or evolving; (2) new claims can be brought against our existing or discontinued assets;

(3) our pollution control and clean-up cost estimates may change, especially when our current estimates are based on preliminary site investigations or agreements; (4) new contaminated facilities and sites may be found, or what we know about existing sites and facilities could change; and (5) where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

We have incurred and will continue to incur operating and capital expenditures costs, some of which could be material, as environmental laws and regulations continue to evolve, change, and become stricter and more robust. Additional regulatory restrictions continue to be placed on activities that may have a detrimental effect on the environment. For this reason, new laws and regulations, amendments and reinterpretations, and stricter enforcement permitting programs result in compliance and remediation obligations that can have a material adverse effect on our operations and financial position now and in the future. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results.

Pipeline Safety Matters

Our gas pipeline systems are subject to federal pipeline safety statutes, such as the Natural Gas Pipeline Safety Act of 1968 (NGPSA), the Pipeline Safety Improvement Act of 2002 (the PSI Act), the Pipeline Inspection, Protection, and Enforcement Act of 2006 (the PIPES Act), the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the 2011 Pipeline Safety Act) and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the 2016 Pipeline Safety Act), as well as regulations promulgated and administered by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities to ensure adequate protection for the public and to prevent accidents and failures. Pursuant to this act, PHMSA has promulgated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs to comprehensively evaluate certain relatively higher risk areas, known as HCAs and moderate consequence areas (MCAs) along pipelines and take additional safety measures to protect people and property in these areas in the event of a pipeline leak or rupture. The HCAs for gas pipelines are predicated on high-population areas, which may include Class 3 and Class 4 areas. An MCA for gas pipelines is also based on population totals in addition to the existence of certain principal, high-capacity roadways, but an MCA does not meet the relative higher population totals of an HCA and therefore are located outside of HCA coverages

Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business, financial condition or results of operations. See Risk Factors under Part I, Item 1A of this Form 10-K for further discussion on pipeline safety matters.

During 2016, PHMSA also proposed new rules and issued a Notice of Public Rule Making for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting, and integrity management requirements on operators. However, PHMSA has since decided to split its 2016 proposed rule, which has become known as the “gas mega rule,” into three separate rulemakings, focusing on (1) maximum allowable operating pressure, integrity assessments and non-high consequence areas known as moderate consequence areas; (2) repair criteria, safety features for pigging, inspections and corrosion control; and (3) gathering lines. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019, becomes effective on July 1, 2020, and imposes numerous requirements on such pipelines, including maximum allowable operating pressure (MAOP) reconfirmation, the assessment of additional pipeline mileage outside of HCAs (including all MCAs and those Class 3 and Class 4 areas found not to be in HCAs) within 14 years of the publication date and at least once every 10 years thereafter, the reporting of exceedances of MAOP, and the consideration of seismicity as a risk factor in integrity management. We are currently assessing the operational and financial impact related to this final rule which will become effective on July 1, 2020 with a 15-year implementation deadline. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020.

On July 31, 2018, PHMSA published an advance notice of proposed rulemaking (ANPRM) requesting public comment on the additional safety measures pipelines facilities are required to take in response to class location changes due to population growth. The class location concept predates the extension of Integrity Management (IM) principles and it has been argued that public safety can be improved if IM measures are implemented as an alternative to pressure reductions, pipe replacements, or hydrostatic pressure testing. While this rulemaking process is expected to be lengthy, efforts to modernize the existing PHMSA regulations may have a material effect on costs.

On October 31, 2019, PHMSA released its "Enhanced Emergency Order Procedures" final rule, which replaces an interim final rule issued by PHMSA in 2016,and allows PHMSA to respond to imminent threats during natural disasters, and when serious flaws are discovered in pipes or in equipment manufacturing processes, or when an accident reveals an industry practice is unsafe. The final rule addressed comments made in response to the 2016 interim final rule, which resulted in several changes in the final rule. The Partnership is currently reviewing the final rule but does not expect any material issues in complying with the final rule, which took effect on December 2, 2019.

The Partnership expects new pipeline safety legislation to be proposed and finalized in 2020 that will reauthorize PHMSA pipeline safety programs, which expired under the 2016 Pipeline Safety Act at the end of September 2019. Any such new pipeline safety legislation could impose more stringent or costly compliance obligations on us and could require us to pursue additional capital projects or conduct integrity or maintenance programs on an accelerated basis, any or all of which tasks could result in the Partnership incurring increased operating costs that could have a material adverse effect on our costs of transportation services as well as our business, results of operations and financial condition.

The existing pipeline safety laws could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure their continued safe and reliable operation and to comply with the federal pipeline safety statutes and regulations. Additional rule makings regarding pipeline safety are likely and, despite compliance with applicable rules and regulations, our pipelines may experience leaks and ruptures that could impact the surrounding population and environment. This may result in civil and/or criminal fines and penalties or third-party property damage claims and could require additional testing or upgrades on the pipeline system unrelated to the incident. It is possible that these costs may not be covered by insurance or recoverable through rate increases. There can be no assurance that future compliance with the requirements will not have a material adverse effect on our pipeline systems and the Partnership's financial position, operational costs, cash flow and our ability to maintain current distribution levels to the extent the increased costs are not recoverable through rates.

U.S. Occupational Safety and Health Administration (OSHA)

Our pipelines are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (OSHA) and comparable state statutes, whose purpose is to protect the health and safety of workers. The OSHA and analogous state agencies oversee the implementation of these laws and regulations. Additionally, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Historically, worker safety and health compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results. While pipeline operators may increase expenditures in the future to comply with higher industry and regulatory safety standards, such increases in costs of compliance, and the extent to which they might be recoverable through our pipeline's rates, cannot be estimated at this time.

Cyber security

We rely on our information technology to process, transmit and store electronic information, including information pipeline operators use to safely operate our assets. We, our operators and other energy infrastructure companies in jurisdictions where we do business continue to face cyber security risks. Cyber security events could be directed against companies in the energy infrastructure industry.

A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets and result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.

TC Energy, the indirect parent of our General Partner and the operator of most of our assets, has a cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, preventions, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a cyber security awareness program for employees. Although TC Energy also has insurance which may cover losses from physical damage to our facilities as a result of a cyber security event, the insurance does not cover all events in all circumstances. There is no certainty that costs incurred related to securing against these threats will be recovered through rates.

EMPLOYEES

We do not have any employees. We are managed and operated by our General Partner. Subsidiaries of TC Energy operate most of our pipelines systems pursuant to operating agreements, with the exception of the Iroquois pipeline system and the Joint Facilities. The Iroquois pipeline system is operated by a wholly owned subsidiary of Iroquois. The Joint Facilities are operated by MNOC, a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.

AVAILABLE INFORMATION

We make available free of charge on or through our website (www.tcpipelineslp.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission (SEC). Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and the Audit Committee Charter of our General Partner are also available on our website under "Corporate Governance." We will also provide copies of these documents at no charge upon request. The information contained on our website is not part of this report.

Item 1A. Risk Factors

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Realization of any of the risks described below could have a material adverse effect on our business, financial condition, including valuation of our equity investments, results of operations and cash flows, including our ability to make distributions to our unitholders. Investors should review and carefully consider all information contained in this report, including the following discussion of risks when making investment decisions relating to our Partnership.

RISKS RELATED TO THE PARTNERSHIP

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we earn net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when losses are incurred and may not make cash distributions during periods when we earn net income.

Our ability to make cash distributions is dependent primarily on our cash flow, financial reserves and working capital borrowings.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate based on, among other things:

- the rates we charge for our transmission and changes in demand for our transportation services;
- legislative or regulatory action affecting the demand for natural gas, the supply of natural gas, the rates we can charge, how we contract for services, our existing contracts, operating costs and operating flexibility;

- the commodity price of natural gas, which could reduce the quantities of natural gas available for transport;
- the creditworthiness of our customers;
- changes in, or new, statutes, regulations or governmental policies by federal, state and local authorities with respect to protection of the environment;
- changes in accounting rules and/or tax laws or their interpretations;
- nonperformance or force majeure by, or disputes with or changes in contract terms with, major customers, suppliers, dealers, distributors or other business partners; and
- changes in, or new, statutes, regulations, governmental policies and taxes, or their interpretations.

Significant changes in energy prices could impact supply and demand balances for natural gas.
Prolonged low oil and natural gas prices can have a positive impact on demand but can negatively impact exploration and development of new natural gas supplies that could impact the availability of natural gas to be transported by our pipelines. Similarly, high commodity prices can increase levels of exploration and development but can reduce demand for natural gas leading to reduced demand for transportation services. Sustained low or high oil and natural gas prices could also impact shippers' creditworthiness that could impact their ability to meet their transportation service cost obligations.

Failure to complete capital projects or acquire additional assets may inhibit our strategy of providing long-term steady and predictable cash distributions.
If we cannot successfully finance and complete capital projects or make and integrate acquisitions that are accretive, we may not be able to maintain historical levels of cash flow and distributions. For example, if we are unable to replace cash flow that may be reduced through future rate proceedings or contract expirations on our pipeline systems, we could be required to take additional proactive measures, including further reductions from the current quarterly 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.

Capital projects or future acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.
Even if we complete capital projects or make acquisitions that we believe will be accretive, these capital projects or acquisitions may nevertheless reduce our cash from operations on a per-unit basis. Any capital project or acquisition involves potential risks, including:

- an inability to complete capital projects on schedule or within the budgeted cost due to, among other factors, the unavailability of required construction personnel, equipment or materials and the risk of cost overruns resulting from inflation or increased costs of materials, labor and equipment;
- a decrease in our liquidity as a result of using a significant portion of our available cash or borrowing capacity to finance the project or acquisition;
- an inability to receive cash flows from a newly built or acquired asset until it is operational; and
- unforeseen difficulties operating in new business areas or new geographic areas.

As a result, our new facilities may not achieve expected investment returns, which could adversely affect our results of operations, financial position or cash flows. If any completed capital projects or acquisitions reduce our cash from operations on a per unit basis, our ability to make distributions may be reduced.

Our indebtedness may limit our ability to obtain additional financing, make distributions or pursue business opportunities.
The amount of the Partnership's current or future debt could have significant consequences to the Partnership including the following:

- our ability to obtain additional financing, if necessary, for working capital, acquisitions, payment of distributions or other purposes may be impaired, or such financing may not be available on favorable terms;

- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our need for cash to fund interest payments on the debt reduces the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders; and
- our flexibility in responding to changing business and economic conditions may be limited.

In addition, our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance, the amount of our current maturities and debt maturing in the next several years and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, lack the ability to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the oil and gas markets or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we may refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities, or sell assets. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

If we are unable to obtain needed capital or financing on satisfactory terms to fund capital projects or future acquisitions, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase.

Over time, our industry's fundamentals have historically made it difficult for some entities to obtain funding. In order to fund some capital project expenditures, we may be required to use cash from our operations, incur borrowings or sell additional common units or other limited partner interests. Using cash from operations will reduce distributable cash flow to our common unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, the covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining funds for capital project expenditures through equity or debt financings, the terms thereof may be less favorable to us and could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate. If funding is not available to us when needed, or is available only on unfavorable terms, we may be unable to execute our business plans, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our financial condition, credit ratings, results of operations, cash flows and ability to make quarterly cash distributions to our unitholders.

Exposure to variable interest rates and general volatility in the financial markets and economy could adversely affect our business, our common unit price, results of operations, cash flows and financial condition.

As of December 31, 2019, $112 million of our total $2,012 million of consolidated debt was subject to variable interest rates. As a result, our results of operations, cash flows and financial condition could be adversely affected by significant increases in interest rates. From time to time, we may enter into interest rate swap arrangements which may increase or decrease our exposure to variable interest rates but there is no assurance that these will be sufficient to offset rising interest rates. As of December 31, 2019, the $450 million borrowed under the Partnership's term loan credit facility under a term loan agreement as amended on September 29, 2017 (the 2013 Term Loan Facility) was hedged by forward starting swap arrangements.

For more information about our interest rate risk, see Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk — Market Risk."

Any impairment of our goodwill, long-lived assets or equity investments will reduce our earnings and could negatively impact the value of our common units.

Consistent with U.S. Generally Accepted Accounting Principles (GAAP), we evaluate our goodwill for impairment at least annually. Our long-lived assets and equity investments, including intangible assets with finite useful lives, are evaluated whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test requires us to consider whether the fair value of the equity investment, not just that of the underlying net assets, has declined and whether that decline is other than temporary. If we determine that impairment is indicated, we would be required to take an immediate non-cash charge to earnings with a corresponding effect on equity and balance sheet leverage as measured by debt to total capitalization. For example, in the fourth quarter of 2018, we recognized impairment charges on Tuscarora's goodwill balance amounting to $59 million and Bison's long-lived assets totaling $537 million.

The risk of future impairments related to our goodwill, long-lived assets or equity investments, will continue to exist. If underlying business assumptions change, there can be no assurance that a future impairment charge will not be made with respect to our remaining balances of our goodwill, equity investments and long-lived assets. This could have a negative impact on the common unit price.

For more information, see Part II, Item 6 "Selected Financial Data" for summary of impairments recognized on our equity investments, goodwill and long-lived assets in the last 5 years. See also Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates — Impairment of Goodwill, Long-Lived Assets and Equity Investments."

We do not own a controlling interest in our equity investments in Northern Border, Great Lakes and Iroquois, which limits our ability to control these assets.

We do not own a controlling interest in our equity investments in Northern Border, Great Lakes and Iroquois and are therefore unable to cause certain actions to occur without the agreement of the other owners. As a result, we may be unable to control the amount of cash distributions received from these assets or the cash contributions required to fund our share of their operations. The major policies of these assets are established by their management committees, which consist of individuals who are designated by each of the partners including us. These management committees generally require at least the affirmative vote of a majority of the partners' percentage interests to take any action. Because of these provisions, without the concurrence of other partners, we would be unable to cause these assets to take or not to take certain actions, even though those actions may be in the best interests of the Partnership or these assets. Further, these assets may seek additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. In the event we do not elect or are unable to make a capital contribution to these assets, our ownership interest would be diluted.

Any disagreements with the other owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

RISKS RELATED TO OUR PIPELINE SYSTEMS

We may experience changes in demand for our transportation services which may lead to an inability of our pipelines to charge maximum rates or renew expiring contracts.

Our primary exposure to market risk and competitive pressure occurs at the time existing shipper contracts expire and are subject to renegotiation and renewal. Majority of our pipeline systems' revenue is generated from long-term, fixed fee transportation agreements. Depending on market conditions at the time of contract expiration and renewal, shippers may be unwilling to renew their contracts for long terms or at favorable rates. The inability of our pipeline systems to extend or replace expiring contracts on comparable terms could have a material adverse effect on our business, financial condition, results of operations and our ability to make cash distributions. Our ability to extend and replace expiring contracts, particularly long-term firm contracts, on terms comparable to existing contracts, depends on many factors beyond our control, including:

- changes in upstream and downstream pipeline capacity, which could impact the pipeline's ability to contract for transportation services;
- the availability and supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply;
- competition from other existing or proposed pipelines;
- contract expirations and capacity on competing pipelines;
- changes in rates upstream or downstream of our pipeline systems, which can affect our pipeline systems' relative competitiveness;
- basis differentials between the market location and location of natural gas supplies;
- the liquidity and willingness of shippers to contract for transportation services on a long-term fixed fee basis; and
- the impact of regulations, public policy and consumer demand for renewal energy on shipper contracting practices.

Rates and other terms of service for our pipeline systems are subject to approval and potential adjustment by FERC, which could limit the 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 effectively 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 current or future costs and could negatively impact their rate of return, results of operations and cash available for distribution. This could result in lower than anticipated distributable cashflow and necessitate a distribution reduction from the current quarterly level of $0.65 per common unit.

We are dependent on the continued availability of and demand for natural gas in relation to our pipeline systems.

As the long-term contracts on our pipeline systems expire, the demand for transportation service on our pipeline systems will depend on the availability of supply from the basins connected to our systems and the demand for natural gas in the markets we serve. Natural gas availability from basins depends upon numerous factors including basin production costs, production levels, environmental regulation, availability of storage and natural gas prices. Our pipeline systems are also dependent on the continued demand for natural gas in their market areas. If supply and/or demand should significantly fall, our pipeline systems may be at risk for loss of contracting or contracting at discounted rates which could impact our revenues.

Our pipeline systems' business systems could be negatively impacted by security threats, including cyber security threats, and related disruptions.

In 2012, the U.S. Department of Homeland Security issued public warnings that indicate that pipelines and other assets might be specific targets of terrorist organizations or "cyber security" events. During 2016, PHMSA posted warnings to all pipeline owners and operators of the importance of safeguarding and securing their pipeline facilities and monitoring their supervisory control and data acquisition (SCADA) systems for abnormal operations and/or indications of unauthorized access or interference with safe pipeline operations based on recent incidents involving environmental activists.

These potential security events might include our pipeline systems or operating systems and may result in damage to our pipeline facilities and affect our ability to operate or control our pipeline assets; their operations could be disrupted and/or customer information could be stolen.

We depend on the secure operation of our physical assets to transport the energy we deliver and our information technology to process, transmit and store electronic information, including information TC Energy uses to safely operate our pipeline systems. Security breaches could expose our business to a risk of loss, misuse or interruption of critical physical assets or information and functions that affect the pipeline operations. Such losses could result in operational impacts, damage to our assets, public or personnel safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions, litigation and a potential material adverse effect on our operations, financial position and results of operations. There is no certainty that costs incurred related to securing against threats will be recovered through rates.

If our pipeline systems do not make additional capital expenditures sufficient to offset depreciation expense, our rate base will decline and our earnings and cash flow could decrease over time.

Our pipeline systems are allowed to collect from their customers a return on their assets or "rate base" as reflected in their financial records, as well as recover a portion of that rate base over time through depreciation. In the absence of additions to the rate base through capital expenditures, the rate base will decline over time, and in the event of a rate proceeding, this could result in reductions in revenue, earnings and cash flows of our pipeline systems.

Our pipeline systems' indebtedness and commitments may limit their ability to borrow additional funds, make distributions to us or capitalize on business opportunities.

Our pipeline systems' respective debt levels and commitments could have negative consequences to each of them and the Partnership, including the following:

- their ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired, or such financing may not be available on favorable terms;
- their need for cash to fund interest payments on the debt reduces the funds that would otherwise be available for operations, future business opportunities and distributions to us;
- their debt level may make them more vulnerable to competitive pressures or a downturn in their business or the economy generally; and
- their debt level may limit their flexibility in responding to changing business and economic conditions.

Our pipeline systems' ability to service their respective debt will depend upon, among other things, future financial and operating performance which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond their control.

Our pipeline systems are subject to operational hazards and unforeseeable interruptions that may not be covered by insurance.

Our pipeline systems are subject to inherent risks such as, ruptures, earthquakes, adverse weather conditions, natural disasters, terrorist activity, civil disobedience or acts of aggression, third-party activity, and pipeline or equipment failure. Any of these risks could cause damage to one of our pipeline systems, business interruptions, a release of pollution or contaminants into the environment or other environmental hazards, or injuries to persons and property. The Partnership could suffer a substantial loss of revenue and incur significant costs to the extent they are not covered by insurance under our pipeline systems' shipper contracts, as applicable. Additionally, if one of our pipeline systems was to experience a serious pipeline failure, a regulator could require us to conduct testing of the pipeline system or upgrade segments of a pipeline unrelated to the failure, resulting in potential costs not covered by insurance or recoverable through rate increases. We could also face a potential reduction in operational parameters which could reduce the capacity available for sale.

Our pipelines could be subject to penalties and fines if they fail to comply with FERC regulations.

Our pipelines are subject to substantial penalties and fines in the event that our pipeline systems have failed to comply with all applicable FERC-administered statutes, rules, regulations and orders, or the terms of their tariffs on file with FERC. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for violations of up to approximately $1.29 million per day for each violation, to revoke existing certificate authority and to order disgorgement of profits associated with any violation.

Our pipeline systems may experience significant costs and liabilities related to compliance with pipeline safety laws and regulations.

Our pipeline systems are subject to pipeline safety statutes and regulations administered by PHMSA, which require pipeline operators to develop integrity management programs.

The ongoing implementation of the pipeline integrity management programs could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure their continued safe and reliable operation and to comply with the federal pipeline safety statutes and regulations. Additionally, we are subject to pipeline safety requirements that may impose more stringent safety obligations, require installation of new or modified safety controls, or perform capital or operating projects on an accelerated basis. Failure to comply with PHMSA's regulations could subject our pipeline systems to penalties, fines or restrictions on our pipeline systems' operations. New legislation or regulations adopted by PHMSA in recent years may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased operating and capital costs and result in operational delays.

The adoption of new PHMSA regulations could result in our pipeline systems incurring significant expenditures to comply, which could have a material adverse effect on our operations, financial position, cash flows, and our ability to maintain current distribution levels to the extent the increased costs are not recoverable through rates. For further discussion on pipeline safety matters, see Part I, Item 1 "Government Regulation" — "Pipeline Safety Matters."

Our pipeline systems are subject to federal, state and local environmental laws and regulations that could impose significant compliance-related costs and liabilities, or make the execution of our growth projects uneconomic or impossible.

New environmental laws, regulations, and enforcement policies could potentially increase our compliance-related costs. For example, since 2015, the EPA has made numerous revisions to the National Ambient Air Quality Standard (NAAQS) for ground-level ozone and its implementation under the CAA. Revisions included making the standard stricter and designating attainment and nonattainment regions. State implementation of the revised ozone NAAQS could increase our compliance costs, for example, by increasing our capital expenditures to install required emissions controls on certain equipment and by increasing operating costs through the prolonging of the permitting process.

Additionally, the promulgation of environmental regulations interpreting the complex and highly contentious definition of WOTUS under the CWA could give rise to significant future compliance-related costs. In 2015, the EPA and U.S. Army Corps of Engineers (Corps) released the Clean Water Rule, which expanded the definition of waters protected under the CWA. The rule would affect the oil and gas pipeline industry for example, by subjecting companies to federal regulation and permitting requirements under the CWA for construction, repair, replacement and even routine maintenance of pipeline facilities in or near waters in the expanded definition. Since 2015, numerous revisions to the rule have been made and debate on the subject between stakeholders has been ongoing. The numerous legal challenges to the many iterations of the rule have led to conflicting court decisions. In 2019, the EPA and the Corps rescinded the rule and on January 23, 2020, the EPA and Corps issued a final rule re-defining the jurisdiction of the federal government with respect to Waters of the U.S., making such jurisdiction narrower than was allowed under the rescinded 2015 Clean Water Rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective and the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over Waters of the U.S. However, there remains the expectation that the January 23, 2020 final rule will be legally challenged in federal district court. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we conduct operations, pipeline companies such as us may become subject to more burdensome federal regulation and CWA permitting requirements. Although there is insufficient information at this time to assess the extent of the impact, an increase in operating costs and capital expenditures is expected.

Additionally, in 2019 the EPA published a proposed rule to implement CWA Section 401, which requires states and/or authorized tribes to grant, deny, or waive a water quality certification for major federal licenses and permits. The proposed rule clarifies various aspects of the current Section 401 regulations, including the actions triggering a Section 401 review, as well as the timeliness and scope of state and tribal review. Notably, the EPA narrows the scope of state and tribal review to preclude them from considering issues other than water quality in their certifications and curtails delays in decision-making by defining the amount of time states and tribes have to consider permit applications.

Furthermore, under certain environmental laws and regulations we may be exposed to substantial liabilities for pre-existing contamination connected to past or current operations. For example, during routine maintenance activities of our pipelines and related facilities, we may discover historical hydrocarbon or PCB contamination. Discovery of such contaminants would require prompt notification to the appropriate governmental authorities and corrective actions to timely mitigate the contamination. Moreover, an accidental release of materials into the environment during the course of our operations may cause us to incur significant costs and liabilities. Remedial costs, penalties from governmental agencies, and other damages could have a material adverse effect on our liquidity, results of operations, and financial condition. For further discussion on environmental matters, see Part I, Item 1 "Government Regulation" — "Environmental Matters".

Our operations are subject to a series of risks arising from the threat of climate change that could lead to increased construction and operating costs and could also potentially reduce demand for our systems and services.

Climate change continues to attract considerable public, governmental, and scientific attention both domestically in the U.S. and internationally. Considered to be the leading driver of climate change, GHG emissions remain at the forefront of the climate change debate. The Partnership, along with the greater oil and gas industry, has a vested interest in the debate since increased scrutiny on the cause of climate change subjects our operations to a number of regulatory, political, litigation, and financial risks. These risks may lead to material adverse effects on our business, financial condition, and results of operations.

Regulatory Risk

With the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, efforts continue to be made at all levels of government within the U.S. to regulate GHGs and define the parameters of regulation. While no comprehensive climate change legislation has been implemented at the federal level, the EPA and numerous state agencies have pursued legal initiatives to reduce GHG emissions using tools like cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that require monitoring and reporting of GHG emissions and limiting GHGs directly from certain sources. Additionally, in 2019 the White House Council on Environmental Quality (CEQ) published draft guidance to assist federal agencies with the consideration of GHG emissions in NEPA analyses of environmental impacts of proposed major federal actions, such as some interstate natural gas pipeline projects. The CEQ took a deferential approach in its guidance by encouraging federal agencies to consider GHG emissions if it would be meaningful to the agencies' decision-making and to rely on their expertise, experience, and the "rule of reason."

In recent years, there has been a particular focus on the regulation of methane, a GHG. The regulation of methane emissions is of importance to the oil and gas industry since methane is the primary component in natural gas. In 2012 and 2016, the EPA promulgated rules requiring certain new, modified or reconstructed facilities in the oil and gas sector to reduce methane and specific volatile organic compounds (VOCs). Notably, the rules required the installation of technology to detect and repair methane leaks from pipelines, new wells, and storage facilities. In 2019, the EPA proposed amendments to the rules to remove regulatory duplication and requested comments on alternative measures that would further this aim. The first approach is to eliminate methane and VOC requirements for sources in the transmission and storage segment in the oil and gas industry, and rescind the methane requirements for sources in the production and processing segments. An alternative approach would be to rescind the methane-specific requirements that apply to all sources in the oil and natural gas industry, without removing the transmission and storage sources from the current source category. Under either alternative, the EPA plans to retain emissions limits for VOCs. While the relaxation of methane requirements on the oil and gas industry is positive, if the proposed amendments are made final, they will likely be legally challenged by interested parties. For example, in the month following the proposed amendments, legislation was introduced in the U.S. Senate to combat methane pollution from pipelines by reducing leaks of methane and other hazardous gases and pollutants. Similar methane leak reduction language was introduced as an amendment to the Senate Commerce, Science, and Transportation Committee's Pipeline Safety Act (PSA) reauthorization bill. The reauthorization of the PSA allows for the continued funding of PHMSA and its pipeline safety program. Methane emissions provisions are now being considered for inclusion in a final bill, which would essentially authorize PHMSA to be another federal regulator of GHG emissions.

The trend towards increased regulation of GHG emissions in the oil and natural gas sector as a means to combat climate change could increase the Partnership's costs of regulatory compliance and/or reduce demand for our systems and services due to regulations and policies incentivizing the use of alternative fuels by consumers and reducing demand for GHG-intensive fossil fuels. However, at this time there remains a great deal of uncertainty in GHG emissions legislation, regulation, and policies at the federal level, as the governing Administration attempts to alleviate burdensome GHG requirements placed on industry that may hinder economic development.

Political Risk
Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the U.S., including climate change related pledges made by candidates seeking the office of the President of the United States in 2020. More than one candidate running for the Democratic nomination for President has declared to combat climate change through various means such as banning hydraulic fracturing of crude oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. A new Presidential Administration could also pursue the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States' withdrawal from the Paris Agreement in November 2020. The Paris Agreement is a non-binding United Nations-sponsored international accord to combat climate change through the establishment of individually-determined GHG emissions reduction goals. The current Administration began the lengthy process of withdrawing the United States from the Agreement in 2019, but the fate of the withdrawal may be dependent on the results of the 2020 Presidential Election.

Litigation Risk
Litigation risks are also increasing, as a number of state and local governments have sought to bring suit against energy companies, including natural gas transmission companies, in an effort to curb energy infrastructure as a means to further regulate GHGs. While state and local governments are considering certain legislative options, they are also increasingly evaluating litigation as an option. For example, some suits alleged that certain energy companies created public nuisances by contributing to global warming effects, such as rising seas levels, and are therefore responsible for resulting roadway and infrastructure damages. Other suits have alleged that the companies have been aware of their operations causing adverse effects of climate change for some time but have defrauded their investors by failing to adequately disclose those impacts. Moreover, state and local governments, as well as non-governmental organizations, are increasingly challenging, on a number of environmental and non-environmental grounds related to GHG review, the granting of federal and state environmental permits even though FERC authorization has been obtained.

Financial Risk
There are also growing financial risks as stockholders and bondholders who are currently invested in fossil-fuel energy companies become increasingly concerned about the potential effects of climate change and consider shifting some or all of their investments into non-fossil fuel energy related sectors. Additionally, some institutional lenders, who provide financing to fossil-fuel energy companies, have become more attentive to sustainable lending practices and may elect not to provide funding for fossil fuel energy companies. The lending and investing practices of institutional lenders have also been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change and the continued funding of fossil fuel producers.

Steadily increasing support for climate change legislation and regulations restricting or regulating GHGs by states and U.S. territories could increase operating and capital costs for our customers and reduce demand for our systems and services.
In the absence of consistency and predictability in GHG emissions legislation, regulation and policies at the federal level, state and U.S. territories are taking GHG regulation into their own hands. The commitment to lowering GHGs is growing significantly and steadfast. In addition to passing legislation and promulgating regulations for GHG emissions, numerous states have taken advantage of tools like cap-and-trade programs, carbon taxes, as well as GHG reporting and tracking

programs. A bipartisan coalition of governors from twenty-five states and U.S. territories have established the U.S. Climate Alliance to combat climate change through the implementation of state policies that are consistent with the U.S. goal of the Paris Agreement. Many of these policies are currently affecting or expected to affect our assets residing in those specific states and significantly increase our compliance-related costs. For example, Oregon recently established a program to regulate air emissions from industrial and commercial facilities by requiring the performance of health risk assessments for new and existing facilities and amending existing air permits if necessary. This may impact GTN's compressor stations in Oregon in the coming years. Additionally, a historically contentious piece of cap-and-trade legislation, which would have significant impacts on our GTN assets in Oregon, is expected to return for consideration by the Oregon legislature in 2020. GTN is expected to be further impacted by Washington state's enactment of a 100 percent clean energy law. Our Tuscarora facilities in California may also be impacted by the state's new climate change plan that includes a GHG cap-and-trade program and regulations on the monitoring and repair of methane leaks at oil and gas sites.

The regulation of GHGs to combat climate change is garnering increasing support, particularly at the state level. The increasing adoption and implementation of legislation and regulations that require reporting of GHGs or otherwise restrict emissions of GHGs will likely increase both operating costs and capital expenditures. Compliance-related costs and additional operating restrictions could have a material adverse effect on our business, financial condition, demand for our systems and services, results of operations, and cash flows. Finally, increasing concentrations of GHGs in the Earth's atmosphere may lead to significant climate changes with an increase in frequency and severity of storms, droughts, floods and other weather events that may have an adverse effect on our financial condition, results of operations, and the financial condition and operations of our customers.

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

The presence of a chemical substance, dithiazine, has been discovered at several facilities on the GTN system, as well as some upstream and downstream connecting pipelines. Dithiazine is a byproduct of triazine which is a liquid chemical scavenger used in the natural gas production industry to remove hydrogen sulfide (H2S) from natural gas streams. None of our pipelines utilize triazine in the facilities or operations, however, dithiazine may drop out of gas streams, under certain conditions, in a powdery form at certain points of pressure reduction. The powdered dithiazine has the potential to interfere with equipment functionality if a sufficient quantity of the material accumulates in certain appurtenances, leading to increased preventative and corrective action costs.

GTN and TC Energy are gathering information and working collaboratively with customers, producers, vendors, and other stakeholders in an effort to develop and implement a joint plan to address each stakeholders' respective issues, and have informed federal and state regulators, trade associations and other stakeholders of the issue. GTN has also taken steps, incurred costs and made capital expenditures to address the matter. Between 2018 and 2019, GTN has spent capital expenditures of approximately $13 million and has incurred operating costs of approximately $2 million. Unless the issue is resolved, GTN expects to spend approximately $6 million in capital expenditures and $1 million in operating costs between 2020 and 2021 to further resolve the matter. There is no assurance that significant additional costs will not be incurred in the future or that dithiazine or other substances will not be identified on our other pipeline systems.

We are exposed to credit risk when a customer fails to perform its contractual obligations.

Our pipeline systems are subject to a risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided and future performance over the remaining contract terms under firm transportation contracts. Our pipelines' FERC approved tariffs limit the amount of credit support that they may require in the event that a customer's creditworthiness is or becomes unacceptable. If a significant customer has financial problems, which result in a delay or failure to pay for services provided by them or contracted for with them, it could have a material adverse effect on our business and results of operations.

The operation of portions of our pipeline systems requires easements or rights-of-way across land owned by Native American tribes, governmental authorities and other third parties, the cost or denial of which could result in disruption to operations and higher costs that adversely affect our business, financial condition and results of operations.

The majority of the land on which our pipeline systems are located is leased pursuant to easements, rights-of-way and other land use rights from individual landowners, Native American tribes, governmental authorities and other third parties, the majority of which are perpetual and obtained through agreements with land owners or legal process, if necessary. Certain rights, however, are subject to renewal and, with respect to tribal land held in trust by the Bureau of Indian Affairs (BIA), approval by the applicable tribal governing authorities and the BIA. The cost of obtaining or renewing rights-of-way across tribal land can be significantly high. The inability to renew a right-of-way on tribal land at reasonable cost could require capital expenditures for removal and relocation of portions of pipeline and disrupt operations. Such costs could negatively impact the results of operations and cash available for distribution from our pipeline systems.

During the second quarter of 2018, rights-of-way expired for approximately 7.6 miles of our Great Lakes pipeline on tribal land located within the Fond du Lac Reservation and Leech Lake Reservation in Minnesota and the Bad River Reservation in Wisconsin. Great Lakes subsequently received a demand letter in April 2019 from the Fond du Lac Tribal Chairman to immediately cease operation of the Great Lakes pipeline and begin the process of removing all infrastructure from tribal land. Following receipt of the demand letter, we executed a Memorandum of Agreement with the Fond du Lac tribal authorities relating to the negotiation of a new right-of-way and are negotiating or in discussions to obtain new rights-of-way with the tribal authorities for the three reservations. We cannot predict the outcome of these negotiations. If we are unable to obtain new easements or rights-of-way across all or a portion of the tribal lands at reasonable rates, or at all, Great Lakes may be required to acquire the necessary rights at significant cost or remove and re-route portions of the pipeline at significant capital expense and disruption to operations that could have a material adverse effect on our financial condition, results of operations and cash flows.

RISKS RELATED TO OUR PARTNERSHIP STRUCTURE

We do not have the same flexibility as corporations to accumulate cash and equity to protect against illiquidity in the future.

We are required by our Partnership Agreement to make quarterly distributions to our unitholders of all available cash, reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per common unit. Accordingly, if we experience a liquidity shortfall in the future, we may not be able to recapitalize by issuing more equity.

Common unitholders have limited voting rights and are not entitled to elect our General Partner or its board of directors.

The General Partner is our manager and operator. Unlike the stockholders in a corporation, holders of our common units have only limited voting rights on matters affecting our business. Unitholders have no right to elect our General Partner or its board of directors. The members of the board of directors of our General Partner, including the independent directors, are appointed by its parent company and not by the unitholders.

Common unitholders cannot remove our General Partner without its consent.

Our General Partner may not be removed except by the vote of the holders of at least 66⅔ percent of the outstanding common units. These required votes would include the votes of common units owned by our General Partner and its affiliates. TC Energy's ownership of approximately 24 percent of our outstanding common units at December 31, 2019, has the practical effect of making removal of our General Partner difficult.

In addition, the Partnership Agreement contains some provisions that may have the effect of discouraging a person or group from attempting to remove our General Partner or otherwise change our management. If our General Partner is removed as our general partner under circumstances where cause does not exist and common units held by our General Partner and its affiliates are not voted in favor of that removal:

- any existing arrearages in the payment of the minimum quarterly distributions on the common units will be extinguished; and
- our General Partner will have the right to convert its general partner interests and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Our Partnership Agreement restricts voting and other rights of unitholders owning 20 percent or more of our common units.

The Partnership Agreement contains provisions limiting the ability of unitholders to call meetings of unitholders or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. Further, if any person or group other than our General Partner or its affiliates or a direct transferee of our General Partner or its affiliates acquires beneficial ownership of 20 percent or more of any class of common units then outstanding, that person or group will lose voting rights with respect to all of its common units. As a result, unitholders have limited influence on matters affecting our operations and third parties may find it difficult to attempt to gain control of us or influence our activities.

We may issue additional common units and other partnership interests, without unitholder approval, which would dilute the existing unitholders' ownership interests. In addition, issuance of additional common units or other partnership interests may increase the risk that we will be unable to maintain the quarterly distribution payment at current levels.

Subject to certain limitations, we may issue additional common units and other partnership securities of any type, without the approval of unitholders.

Based on the circumstances of each case, the issuance of additional common units or securities ranking senior to, or on parity with, the common units may dilute the value of the interests of the then-existing holders of common units in the net assets of the Partnership. In addition, the issuance of additional common units may increase the risk that we will be unable to maintain the quarterly distribution payment at current levels.

Our common unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner generally has unlimited liability for the obligations of a limited partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law and conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states. Our unitholders could be liable for any and all of our obligations as if our unitholders were a general partner if a court or government agency determined that:

- the Partnership had been conducting business in any state without compliance with the applicable limited partnership statute; or
- the right, or the exercise of the right, by the unitholders as a group to remove or replace our General Partner, to approve some amendments to the Partnership Agreement or to take other action under the Partnership Agreement constituted participation in the "control" of the Partnership's business.

In addition, under some circumstances, such as an improper cash distribution, a unitholder may be liable to the Partnership for the amount of a distribution for a period of three years from the date of the distribution.

Our General Partner has a limited call right that may require common unitholders to sell their common units at an undesirable time or price.

If at any time our General Partner and its affiliates own 80 percent or more of the common units, the General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or us, to acquire all of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a consequence, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would desire to receive upon sale. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2019, the General Partner and its affiliates own approximately 24 percent of our outstanding common units.

Our Partnership Agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties.

The Partnership Agreement contains provisions that eliminate the fiduciary standards to which the General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the Partnership Agreement does not provide for a clear course of action. This provision entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board of Directors;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the Partnership Agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our Board of Directors or to establish a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

The credit and business risk profiles of our General Partner and TC Energy could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner and TC Energy may be factors in credit evaluations of a master limited partnership because our General Partner can exercise control over our business activities, including our cash distribution and acquisition strategy and business risk profile. Other factors that may be considered are the financial conditions of our General Partner and TC Energy, including the degree of their financial leverage and their dependence on cash flows from us to service their indebtedness.

Costs reimbursed to our General Partner are determined by our General Partner and reduce our earnings and cash available for distribution.

Prior to making any distribution on the common units, we reimburse our General Partner and its affiliates, including officers and directors of the General Partner, for all expenses incurred by our General Partner and its affiliates on our behalf. During the year ended December 31, 2019, we paid fees and reimbursements to our General Partner in the amount of $4 million (2018 and 2017 — $4 million each). Our General Partner, in its sole discretion, determines the amount of these expenses. In addition, our General Partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the General Partner. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions.

Changes in TC Energy's costs or their cost allocation practices could have an effect on our results of operations, financial position and cash flows.
Under the Partnership Agreement, the Partnership's pipeline systems operated by TC Energy are allocated certain costs of operations at TC Energy's sole discretion. Accordingly, revisions in the allocation process or changes to corporate structure may impact the Partnership's operating results. TC Energy reviews any changes and their prospective impact for reasonableness, however there can be no assurance that allocated operating costs will remain consistent from period to period.

TAX RISKS

Our tax treatment depends on our status as a partnership and exemption from entity level taxes for U.S. federal, state and local income tax purposes. If we were to be treated as a corporation or otherwise become subject to a material amount of entity level taxation for U.S. federal, state and local tax purposes, our cash available for distribution to unitholders and the value of our common units could be substantially reduced.
The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes if the Internal Revenue Service (IRS) were to determine that we fail to satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us. Failing to meet the qualifying income requirement or any legislative, administrative or judicial change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation at the entity level.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income taxes on our taxable income at the applicable corporate tax rate, and we would likely have to pay state income taxes at varying rates. Distributions to our unitholders (to the extent of our earnings and profits) would generally be taxed again to unitholders as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. In the event of a tax imposed upon us as a corporation, the cash available for distribution to our unitholders could be substantially reduced and result in a material reduction in the anticipated cash flow and after-tax return to unitholders, which in turn would likely have a negative impact on the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for U.S. federal, state, or local income tax purposes, then specified provisions of the Partnership Agreement relating to distributions will be subject to change. These changes would include a decrease in cash distributions to unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.
The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships including legislative proposals that would have eliminated the qualifying income exception we rely upon; thus, treating certain publicly traded partnerships as corporations for U.S. federal income tax purposes. For example, the "Clean Energy for America Act," which is similar to legislation that was proposed during the Obama Administration, was introduced in the Senate on May 2, 2019. If enacted, this proposal would, among other things, repeal the qualifying income exception in Section 7704(d)(1)(E) of the Internal Revenue Code upon which we rely for our status as a partnership for U.S. federal income tax purposes.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future. We believe the income that we treat as qualifying satisfies the requirements under current regulations.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. Unitholders are urged to consult with tax advisors with respect to the status of regulatory or administrative developments and proposals and their potential effect on their investment in our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Under our limited Partnership Agreement, our general partner is permitted to make elections under the new rules to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our common units during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Unitholders may be required to pay taxes on income from us even if they receive no cash distributions.

Because unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash distributed, unitholders may be required to pay U.S. federal income taxes and, in some cases, state and local income taxes on their allocable share of our income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions equal to their allocable share of our taxable income or even the tax liability that results from that income.

Tax gains or losses on the disposition of common units could be different than expected.

If unitholders sell their common units, they will recognize a taxable gain or loss equal to the difference between the amount realized and their adjusted tax basis in those common units. Prior distributions in excess of the total net taxable income that a unitholder was allocated for a common unit, which distributions decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income if the common unit is sold at a price greater than its adjusted tax basis in that common unit, even if the price is less than the original cost. A substantial portion of the amount realized on the sale of common units, whether or not representing a gain, may be ordinary income to unitholders due to certain items such as potential depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units. If the IRS were to successfully contest some conventions we use, unitholders could recognize more taxable gain on the sale of common units than would be the case under those conventions without the benefit of decreased taxable income in prior years.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the 2017 Tax Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" may be limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion to the extent such depreciation, amortization or depletion is not capitalized into cost of goods sold with respect to inventory. The interest limitation does not apply to regulated pipeline businesses and, therefore, we believe that our interest expense is fully deductible. If the IRS contests this position or if further guidance is issued contrary to the positions taken, the unitholder's ability to deduct this interest expense could be limited.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business (effectively connected income). Income allocated to our unitholders and any gain from the sale of our common units will generally be considered "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferees but were not withheld. Because the "amount realized" includes a partner's share of the partnership's liabilities, 10% of the amount realized could exceed the total cash purchase price for the units. However, pending the issuance of final regulations, the IRS has suspended the application of this withholding rule to transfers of publicly traded interests in publicly traded partnerships. If recently promulgated regulations are finalized as proposed, such regulations would provide, with respect to transfers of publicly traded interests in publicly traded partnerships effected through a broker, that the obligation to withhold is imposed on the transferor's broker and that a partner's "amount realized" does not include a partner's share of a publicly traded partnership's liabilities for purposes of determining the amount subject to withholding. However, it is not clear when such regulations will be finalized and if they will be finalized in their current form.

We treat a purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization conventions that may not conform to all aspects of specified Treasury Regulations. A successful challenge to those conventions by the IRS could adversely affect the amount of tax benefits available to unitholders or could affect the timing of tax benefits or the amount of taxable gain from the sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to unitholders' tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Final Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the General Partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets.

Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction. Pursuant to the Bipartisan Budget Act of 2015, the IRS can isolate the resulting allocation adjustments that increase tax from those that decrease tax and assess tax at the partnership level, without netting the adjustments. Such a result would reduce the cash available for distribution by the partnership.

A successful IRS challenge to these methods, calculations or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount or character of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to U.S. federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not live in any of those jurisdictions. We may be required to withhold income taxes with respect to income allocable or distributions made to our unitholders. In addition, unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements.

We currently own assets in multiple states, many of which currently impose a personal income tax on individuals. Generally, these states also impose income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is the unitholders' responsibility to file all required U.S. federal, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Please read Item 1. Business for a description of our principal physical properties and a map showing the locations of our pipeline systems. Our pipeline systems are constructed and operated on property owned by individuals, governmental authorities, Native American tribes and other third parties pursuant to leases, easements, rights-of-way, permits and licenses, the majority of which are perpetual. Our pipeline systems also own or lease land for compressor stations, meter stations and pipeline field offices. Certain land use rights, in particular rights-of-way on tribal land held in trust by the BIA, are subject to periodic renewal, periodic payments, encumbrances and/or restrictions. We believe that we generally have sufficient rights, title and interest in the properties needed to operate our pipeline systems and conduct our business and that such periodic renewals, rental payments, encumbrances and restrictions should not materially detract from the value of our pipeline systems or materially interfere with the operation of their business.

See Part I, Item 1A "Risk Factors — Risks Related to Our Pipeline Systems" for further information regarding risks related to property rights.

Item 3. Legal Proceedings

We may be involved in various legal proceedings from time to time that arise in the ordinary course of business. Information regarding our pipeline systems' rate proceedings is described in Item 1. "Business — Government Regulation — Regulatory and Rate Proceedings" is incorporated herein by reference. Information on our legal proceedings can be found under Note 22 — Contingencies within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

As of February 19, 2020, there were approximately 27 holders of record of our common units. Our common units trade on the NYSE under the symbol "TCP."

As of February 19, 2020, the Partnership had 71,306,396 common units outstanding, of which 54,221,565 were held by non-affiliates and 17,084,831 common units were held by subsidiaries of TC Energy, including 5,797,106 common units held by our General Partner. Additionally, TC Energy, through our General Partner, owns 100 percent of our IDRs and a two percent general partner interest in the Partnership. TC Energy also holds 100 percent of our 1,900,000 outstanding Class B units. There is no established public trading market for our IDRs and Class B units.

Further details regarding our distributions can be found under Note 15 — Cash Distributions within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Item 6. Selected Financial Data

The selected financial data should be read in conjunction with the financial statements, including the notes thereto, and Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

(millions of dollars, except per common unit amounts)	2019	2018	2017	2016[(a)]	2015[(a)]
Income Data (for the year ended December 31)					
Transmission revenues	**403**	549[(e)]	422	426	417
Equity earnings[(b)]	**160**	173	124	97	97
Impairment of equity-method investment[(c)]	**—**	—	—	—	(199)
Impairment of goodwill[(d)]	**—**	59	—	—	—
Impairment of long-lived assets[(e)]	**—**	537	—	—	—
Net income (loss)	**297**	(165)	263	263	58
Net income (loss) attributable to controlling interests	**280**	(182)	252	248	37
Basic and diluted net (loss) income per common unit	**$3.74**	$(2.68)	$3.16	$3.21[(f)]	$(0.03)[(f)]
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$2.60**	$2.60	$3.94	$3.71	$3.51
Balance Sheet Data (at December 31)					
Total assets	**2,853**	2,899	3,559	3,354	3,459[(g)]
Long-term debt (including current maturities)	**2,012**	2,108	2,403	1,911	1,971[(g)]
Partners' equity	**760**	699	1,068	1,272	1,391

(a) Recast information to consolidate PNGTS as a result of an additional 11.81 percent in PNGTS that was acquired from a subsidiary of TC Energy on June 1, 2017. Prior to this transaction, the Partnership owned a 49.9 percent interest in PNGTS that was acquired from TC Energy on January 1, 2016. Please read Note 2 — Significant Accounting Policies — Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules".

(b) Equity earnings represent our share in investee's earnings and do not include any impairment charge on our equity investments.

(c) Represents the impairment charge on our investment in Great Lakes. The equity earnings as presented in 2015 did not include this impairment charge.

(d) Please read Note 4 — Goodwill and Regulatory, Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules" for more information.

(e) Please read Note 7 — Property, plant and Equipment, Notes to the Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more information.

(f) Represents basic and diluted net income per common unit prior to recast.

(g) As a result of the application of Accounting Standards Update (ASU) No. 2015-03 "Interest-Imputation of Interest" and similar to the presentation of debt discounts, debt issuance costs previously reported as other assets in the balance sheet were reclassified as an offset against their respective debt liabilities.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis (MD&A) is intended to give our unitholders an opportunity to view the Partnership through the eyes of our management. We have done so by providing management's current assessment of, and outlook of the business of the Partnership. This MD&A should be read in conjunction together with Part I Item 1. "Business" and the accompanying December 31, 2019 audited financial statements and notes included in Part IV, Item 15. "Exhibits and Financial Statement Schedules." Our discussion and analysis includes the following:

- EXECUTIVE OVERVIEW;
- HOW WE EVALUATE OUR OPERATIONS;
- RESULTS OF OPERATIONS;
- LIQUIDITY AND CAPITAL RESOURCES;
- CRITICAL ACCOUNTING ESTIMATES;
- CONTINGENCIES; and
- RELATED PARTY TRANSACTIONS.

EXECUTIVE OVERVIEW

Financial Performance Highlights

Our 2019 highlights are summarized as follows:

- Generated net income attributable to controlling interests of $280 million or $3.74 per common unit compared to a net loss of $182 million or $2.68 per common unit in 2018
- Generated adjusted earnings of $280 million or $3.74 per common unit compared to $317 million or $4.18 per common unit in 2018
- Generated both EBITDA and Adjusted EBITDA of $460 million in 2019 compared to $27 million and $526 million in 2018, respectively
- Declared and paid cash distributions totaling $2.60 per common unit, or $0.65 per quarter, for both 2019 and 2018
- Generated Distributable Cash flow of $340 million compared to $391 million in 2018
- Reduced debt balance by $106 million during 2019
- Received approval from FERC for both Iroquois and Tuscarora rate settlements on May 2, 2019
- S&P upgraded credit rating to BBB/Stable from BBB−/Stable

Please see "How We Evaluate Our Operations Section" for more information on our Non-GAAP Financial Measures: EBITDA, Adjusted earnings and Adjusted earnings per common unit and Distributable Cash Flows.

Outlook of Our Business

With the return to a stable regulatory environment in 2019 and our financial metrics solidly in line with a self-funding business model, we believe our pipeline systems, which are largely backed by long-term, ship-or-pay contracts, will deliver consistent financial performance going forward and support our current quarterly distribution level of $0.65 per common unit for the foreseeable future.

We have transformed our business strategy and are focusing on taking advantage of North America's abundant natural gas supply and our assets' connectivity to premium markets to compete for organic growth within our existing footprint. Our largest assets, GTN, Northern Border and Great Lakes, continued to benefit from positive market conditions in 2019. Additionally, PNGTS' PXP and Westbrook XPress projects continued to advance, with PXP Phase II and Westbrook XPress Phase I going into service on November 1, 2019. In 2019, we also announced the following new growth projects:

- GTN XPress project, the largest organic opportunity in our 20-year history, which will enhance system reliability through horsepower replacements and other reliability work and will provide up to 250,000 Dth/day of additional firm transportation services by late 2023; and
- Tuscarora XPress project, an expansion project that will transport an additional 15,000 Dth/day of natural gas along Tuscarora's system, increasing its capacity by seven percent.

Additionally, following successful binding open seasons, we announced the following projects which are in development and still subject to various conditions including corporate and regulatory approvals and final contracting or investment decisions:

- North Baja XPress project, an expansion project that will transport an additional 495,000 Dth/day of additional volumes of natural gas along North Baja's mainline system with an estimated in-service date of November 2022; and
- Iroquois ExC Project which involves compressor enhancements at existing compressor stations along the Iroquois pipeline that will increase Iroquois' capacity by approximately 125,000 Dth/day with an estimated in-service date of November 2023.

We continue to pursue new opportunities to capture the highest value from our pipelines and are actively seeking opportunities to further optimize our pipelines' capacity through potential expansion projects or commercial, regulatory and operational changes in response to positive supply fundamentals. Finally, we continue to evaluate redeployment alternatives for our Bison pipeline following expiration of its remaining long-term contracts in January 2021, including the potential to reverse the pipeline to transport growing associated natural gas supplies from the Bakken area. The safe and reliable operation of our pipeline assets remains our top priority as we prudently fund ongoing capital expenditures, repay debt and manage our financial metrics.

(Please see also "Item 1. Business — Recent Business Developments" for more information on these projects and other matters that could potentially impact our results of operations in the future.)

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 each enhance the understanding of our operating performance. We use the following non-GAAP measures:

EBITDA

We use EBITDA as an approximate measure of our current operating profitability. It measures our earnings from our pipeline systems before certain expenses are deducted.

Adjusted EBITDA, Adjusted Earnings and Adjusted Earnings per common unit

The evaluation of our financial performance and position from the perspective of earnings and EBITDA is inclusive of the following 2018 items which are one-time or non-cash in nature:

- Bison's contract termination proceeds amounting to $97 million recognized as revenue;
- the $537 million impairment charge related to Bison's remaining balance of property, plant and equipment; and
- the $59 million impairment charge related to Tuscarora's goodwill.

However, we do not believe this is reflective of our underlying operations during the periods presented. Therefore, we have presented Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit as non-GAAP measures that exclude the 2018 impacts of the $596 million non-cash impairment charges and the one-time $97 million revenue item relating to Bison's contract terminations. We had no similar adjustments in the 2019 and 2017 periods.

Distributable Cash Flows

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period. Our distributable cash flow includes Adjusted EBITDA and therefore excludes 2018's $596 million non-cash impairment charges and the one-time $97 million revenue item from receipt of proceeds relating to Bison's contract terminations.

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

RESULTS OF OPERATIONS

The ownership interests in our pipeline assets were our only material sources of income during the periods presented. Therefore, our results of operations and cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems.

Year Ended December 31, 2019 Compared with the Year Ended December 31, 2018

(unaudited) (millions of dollars, except per common unit amounts)	2019	2018	$ Change[b]	% Change[b]
Transmission revenues	**403**	549	(146)	(27)
Equity earnings	**160**	173	(13)	(8)
Impairment of long-lived assets	**—**	(537)	537	100
Impairment of goodwill	**—**	(59)	59	100
Operating, maintenance and administrative	**(105)**	(101)	(4)	(4)
Depreciation	**(78)**	(97)	19	20
Financial charges and other	**(83)**	(92)	9	10
Net income (loss) before taxes	**297**	(164)	461	*
Income taxes	**1**	(1)	2	*
Net income (loss)	**298**	(165)	463	*
Net income attributable to non-controlling interests	**18**	17	1	6
Net income (loss) attributable to controlling interests	**280**	(182)	462	*
Adjusted earnings[a]	**280**	317	(37)	(12)
Net income (loss) per common unit	**3.74**	(2.68)	6.42	*
Adjusted earnings per common unit[a]	**3.74**	4.18	(0.44)	(11)

(a) Adjusted earnings and Adjusted earnings per common unit are non-GAAP measures for which reconciliations to the appropriate GAAP measures are provided below.

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

* Change is greater than 100 percent.

For the year ended December 31, 2019, the Partnership generated net income attributable to controlling interests of $280 million compared to a loss of $182 million for the same period in 2018, resulting in a net income per common unit during the year of $3.74 compared to a loss $2.68. The loss in 2018 was primarily due to the recognition of non-cash impairments relating to Bison's property, plant and equipment and Tuscarora's goodwill partially offset by the $97 million revenue proceeds from Bison's contract terminations in the fourth quarter of 2018. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates — Impairment of Goodwill, Long-Lived Assets and Equity Investments" section for more details.

Adjusted earnings was lower by $37 million for the year ended December 31, 2019, a decrease of $0.44 per common unit. This decrease was primarily due to the net effect of:

Transmission revenues — Excluding the non-recurring $97 million revenue proceeds from Bison's contract terminations in 2018 noted above, revenues for 2019 were lower by $49 million due largely to the decrease in revenue from Bison. As a result of early contract pay out, Bison was only approximately 40 percent contracted beginning in 2019 compared to 100 percent contracted in 2018, resulting in decreased revenue of approximately $48 million.

Revenue from GTN, North Baja, Tuscarora and PNGTS was largely comparable to prior year. The scheduled rate decreases on our pipelines as a result of the 2018 FERC Actions were primarily offset by increased discretionary revenue as a result of strong natural gas flows mainly out of WCSB and solid contracting across our Consolidated Subsidiaries. See also Part I, Item 1. "Business — Government Regulations — 2018 FERC Actions."

Equity Earnings — The $13 million decrease was primarily due to the net effect of the following:

- decrease in Iroquois' equity earnings as a result of a decrease in its revenue. The sustained cold temperatures in the first quarter of 2018 resulted in incremental seasonal winter sales that were not achieved in the same period of 2019. Additionally, a scheduled reduction of Iroquois' existing rates as part of the 2019 Iroquois Settlement went into effect; and
- decrease in Great Lakes' equity earnings as a result of decrease in its revenue and increase in its operating costs. The sustained cold temperatures in the first quarter of 2018 resulted in incremental seasonal winter sales for Great Lakes that were not achieved in the same period of 2019. Additionally, there was an increase in its operating costs related to its compliance programs, estimated costs related to right-of-way renewals and an increase in TC Energy's allocated management and corporate support functions expenses and common costs such as insurance.

Operation and maintenance expenses — The increase in operation and maintenance expenses was primarily due to the overall net impact of the following:

- increase in operational costs related to our pipeline systems' compliance programs;
- increase in TC Energy's allocated costs related to corporate support functions and common costs such as insurance; and
- decrease in overall property taxes primarily due to lower taxes assessed on Bison.

Depreciation — The decrease in depreciation expense in 2019 was a direct result of the long-lived asset impairment recognized during the fourth quarter of 2018 on Bison which effectively eliminated the depreciable base of the pipeline.

Financial charges and other — The $9 million decrease in financial charges and other expenses was primarily attributable to the repayment of our $170 million Term Loan during the fourth quarter of 2018 and repayment of borrowings under our Senior Credit Facility during the first quarter of 2019.

Year Ended December 31, 2018 Compared with the Year Ended December 31, 2017

(unaudited) (millions of dollars, except per common unit amounts)	2018	2017	$ Change[(b)]	% Change[(b)]
Transmission revenues	**549**	422	127	30
Equity earnings	**173**	124	49	40
Impairment of long-lived assets	**(537)**	—	(537)	(100)
Impairment of goodwill	**(59)**	—	(59)	(100)
Operating, maintenance and administrative	**(101)**	(103)	2	2
Depreciation	**(97)**	(97)	—	—
Financial charges and other	**(92)**	(82)	(10)	(12)
Net income (loss) before taxes	**(164)**	264	(428)	*
Income taxes	**(1)**	(1)	—	—
Net income (loss)	**(165)**	263	(428)	*
Net income attributable to non-controlling interests	**17**	11	6	55
Net income (loss) attributable to controlling interests	**(182)**	252	(434)	*
Adjusted earnings[(a)]	**317**	252	65	26
Net income (loss) per common unit	**(2.68)**	3.16	5.84	*
Adjusted earnings per common unit[(a)]	**4.18**	3.16	1.02	32

(a) Adjusted earnings and Adjusted earnings per common unit are non-GAAP measures for which reconciliations to the appropriate GAAP measures are provided below.

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

* Change is greater than 100 percent.

During 2018, the Partnership generated a net loss attributable to controlling interests of $182 million compared to net income of $252 million in 2017, resulting in a net loss per common unit during the year of $2.68 after allocations to the General Partner and to the Class B units. The resulting loss was primarily due to the recognition of non-cash impairments relating to Bison's property, plant and equipment and Tuscarora's goodwill partially offset by the $97 million revenue proceeds from Bison's contract terminations. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates — Impairment of Goodwill, Long-Lived Assets and Equity Investments" section for more details.

Adjusted earnings increased by $65 million, an increase of $1.02 per common unit. This increase was primarily due to the net effect of:

Transmission revenues — Excluding the $97 million revenue proceeds from Bison's contract terminations, our 2018 annual revenues were higher than those in 2017 by $30 million due to the following:

- Higher net revenue from GTN primarily due to incremental long-term services sold by GTN associated with increased available upstream capacity following debottlenecking activities on TC Energy's pipelines partially offset by lower revenues from its short-term discretionary services compared to the same period in 2017. The increase was further offset by the $10 million provision for revenue sharing payment made by GTN as part of the 2018 GTN Settlement whereby GTN agreed to refund $10 million to its maximum rate customers from January 1 to October 31, 2018;
- Higher revenue from PNGTS primarily due to incremental contracting from PNGTS' C2C Contracts and the PXP Phase I contracts combined with an increase in discretionary services due to inclement weather in the northeast U.S. during the first quarter of 2018, partially offset by certain expiring winter contracts; and
- Increase in short-term firm transportation services sold by North Baja.

Equity earnings — The $49 million increase in 2018 compared to 2017 was primarily due to the inclusion of equity earnings from Iroquois for the full twelve months of 2018 compared to only seven months in 2017 (our 49.34 percent ownership was effective June 1, 2017), as well as the increase in Iroquois' short-term discretionary services sold during the 2018 period as a result of the colder winter weather in the northeast U.S. Additionally, equity earnings from Great Lakes increased as a result of higher short-term incremental sales during the year and the elimination of Great Lakes' revenue sharing mechanism that began in 2018 as part of 2017 Great Lakes Settlement.

Financial charges and other — The $10 million increase was mainly attributable to additional borrowings to finance the Partnership's acquisition of an additional 11.81 percent interest in PNGTS and 49.34 percent in Iroquois on June 1, 2017 (the 2017 Acquisition) combined with an increase in interest charges on our variable rate debt.

Net income (loss) attributable to non-controlling interests — The Partnership had a net increase amounting to $6 million primarily due to the increase in revenue earned by PNGTS.

Non-GAAP Financial Measures: Adjusted earnings and Adjusted earnings per common unit

Reconciliation of Net income (loss) attributable to controlling interests to Adjusted earnings

(millions of dollars) **Year ended December 31**	**2019**	**2018**	**2017**
Net income attributable to controlling interests	**280**	(182)	252
Add: Impairment of goodwill	**—**	59	—
Add: Impairment of long-lived assets	**—**	537	—
Less: Revenue proceeds from Bison's contract terminations	**—**	(97)	—
Adjusted earnings	**280**	317	252

Reconciliation of Net income (loss) per common unit to Adjusted earnings per common unit

Year ended December 31	2019	2018	2017
Net income (loss) per common unit-basic and diluted[(a)]	**3.74**	(2.68)	3.16
Add: per unit impact of impairment of goodwill	**—**	0.81[(b)]	—
Add: per unit impact of impairment of long-lived assets	**—**	7.38[(c)]	—
Less: per unit impact of revenue proceeds from Bison's contract terminations	**—**	(1.33)[(d)]	—
Adjusted earnings per common unit	**3.74**	4.18	3.16

(a) See also Note 14 of the Partnership's consolidated financial statements included in Part IV. Item 15. "Exhibits and Financial Statement Schedules" for details of the calculation of net income (loss) per common unit.

(b) Computed by dividing the $59 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

(c) Computed by dividing the $537 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

(d) Computed by dividing the $97 million revenue, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

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 operating expenses, debt service and cash distributions (including those distributions made to TC Energy through our General Partner and as holder of all our Class B units) primarily with operating cash flow.

At December 31, 2019, the balance of our cash and cash equivalents was higher than our position at December 31, 2018 by approximately $50 million and our overall debt balance was lower by $106 million. We continue to use available cash to fund ongoing capital expenditures and repay debt to levels that prudently manage our financial metrics.

We believe our cash position, remaining borrowing capacity on our Senior Credit Facility (see table below), and our operating cash flows are sufficient to fund our short-term liquidity requirements, including distributions to our unitholders, ongoing capital expenditures and required debt repayments.

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

(millions of dollars) December 31	2019	2018	2017
Total capacity under the Senior Credit Facility	**500**	500	500
Less: Outstanding borrowings under the Senior Credit Facility	**—**	40	185
Available capacity under the Senior Credit Facility	**500**	460	315

Our pipeline systems' principal sources of liquidity are cash generated from operating activities, long-term debt offerings, bank credit facilities and equity contributions from their owners. Except as noted below, our pipeline systems have historically funded operating expenses, debt service and cash distributions to their owners primarily with operating cash flow.

- Since the fourth quarter of 2010, however, Great Lakes has funded its debt repayments with cash calls to its owners and we have contributed approximately $10 million in 2019 and $9 million each for 2018 and 2017.
- In August 2019, the Partnership made an equity contribution to Iroquois of approximately $4 million. This amount represented the Partnership's 49.34 percent share of a $7 million capital call from Iroquois to cover costs of regulatory approvals related to their ExC Project.
- From time to time, Northern Border requests equity contributions from or makes returns of capital distributions to its partners to manage its preferred capitalization levels. In June 2019, we received a return of capital distribution from Northern Border amounting to $50 million and used those proceeds to partially repay our 2013 Term Loan Facility due in 2021. In 2017, we made an equity contribution to Northern Border amounting to $83 million, which was used by Northern Border to reduce the outstanding balance on its revolver. The $50 million and $83 million amounts represent our 50 percent share of Northern Border's distribution and contribution, respectively.
- Bison's remaining contracts will continue until January of 2021. In 2019, Bison generated revenues of $32 million and is expected to produce comparable results in 2020. We continue to explore alternative transportation-related options for Bison and we believe commercial potential exists to reverse the direction of natural gas flow on Bison for deliveries onto third party pipelines and ultimately connect into the Cheyenne hub. Notwithstanding the results of these commercial activities, Bison will continue to incur costs related to property tax and operating and maintenance costs of approximately $6 million per year.

Capital expenditures are funded by a variety of sources, as noted above. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends on their financial condition 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.

Summarized Cash Flow

Year Ended December 31, (millions of dollars)	**2019**	**2018**	**2017**
Net cash provided by (used in):			
Operating activities	**412**	540	376
Investing activities	**(32)**	(35)	(761)
Financing activities	**(330)**	(505)	354
Net increase in cash and cash equivalents	**50**	—	(31)
Cash and cash equivalents at beginning of the period	**33**	33	64
Cash and cash equivalents at end of the period	**83**	33	33

Cash Flow Analysis for the Year Ended December 31, 2019 compared to Same Period in 2018

Operating Cash Flows

In the twelve months ended December 31, 2019, the Partnership's net cash provided by operating activities decreased by $128 million compared to the same period in 2018 primarily due to the net effect of:

- lower net cash flow from operations of our Consolidated Subsidiaries due to lower revenue from Bison as a result of the contract terminations in 2018 (60 percent of Bison contracts bought out in 2018) and an overall increase in our operating expenses as discussed in more detail in "Results of Operations" above; and
- increase in distributions received from operating activities of equity investments primarily as a result of:
- lower maintenance capital spending during 2019 on Northern Border; and
- an increase in distributions from Iroquois related to an increase in its cash generated from strong discretionary revenues in prior years.

Investing Cash Flows

During the twelve months ended December 31, 2019, the Partnership's cash used in our investing activities decreased by $3 million compared to the same period in 2018 primarily due to the net impact of the following:

- higher maintenance capital expenditures on GTN for major compressor equipment overhauls and pipe integrity projects, initial spending on our GTN XPress project and continued capital spending on our PXP and Westbrook XPress projects and other growth projects;
- equity contribution to Iroquois of approximately $4 million representing the Partnership's 49.34 percent share of a $7 million capital call from Iroquois to cover costs of regulatory approvals related to their capital project; and
- $50 million distribution received from Northern Border that was considered a return of investment during the second quarter of 2019.

Financing Cash Flows

The Partnership's net cash used for financing activities was $175 million lower in the twelve months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- $191 million decrease in net debt repayments;
- $29 million decrease in distributions paid to common unitholders as a result of a lower per unit declaration beginning in second quarter 2018 in response to the 2018 FERC Actions;
- $8 million increase in distributions paid to non-controlling interests during 2019 as a result of increased income generated by PNGTS;
- $2 million decrease in distributions paid to Class B units in 2019 as compared to 2018; and
- $40 million decrease in cash from equity issuances in 2019 as the At-the-market Equity Issuance program (ATM program) was suspended during the first quarter of 2018.

Cash Flow Analysis for the Year Ended December 31, 2018 compared to Same Period in 2017

Operating Cash Flows

Net cash provided by operating activities increased by $164 million in the twelve months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of:

- higher cash flow from operations at Bison due to the $97 million cash proceeds received from the contract terminations agreement reached with two of its customers as described in the "Results of Operations" and "Critical Accounting Estimates — Impairment of Goodwill, Long-Lived Assets and Equity Investments" sections;
- addition of distributions from Iroquois for the twelve months in 2018 as compared to the period from June 1, 2017 to the end of December in 2017;
- higher distributions received from Great Lakes primarily due to an increase in its revenue as a result of its higher short-term incremental sales during the year and the elimination of Great Lakes' revenue sharing mechanism that began in 2018 as part of Great Lakes rate settlement in 2017;
- higher cash flow from operations at PNGTS and North Baja primarily resulting from an increase in their revenues; PNGTS' revenue was higher due to its incremental contracting partially offset by certain expiring winter contracts while North Baja's revenue was higher due to an increase in its short-term firm transportation services; and
- higher interest paid attributable to additional borrowings to finance the 2017 Acquisition.

Investing Cash Flows

Net cash used in investing activities decreased by $726 million in the twelve months ended December 31, 2018 compared to the same period in 2017 due to the net effect of:

- $646 million total cash payments to TC Energy during 2017 for the 2017 Acquisition;
- $83 million equity contribution to Northern Border in 2017 representing our 50 percent share of a requested capital contribution to reduce the outstanding balance of Northern Border's revolving credit facility;
- $10 million unrestricted cash distribution received from Iroquois during 2018, which was $5 million higher than the amount received in 2017;
- $11 million increase in capital expenditures in 2018 related to ongoing maintenance projects; the increase in 2018 reflected timing of payments as the scope of the maintenance work was relatively comparable in 2018 and 2017; and
- $3 million increase in customer advances for construction related to an interconnect project on GTN.

Financing Cash Flows

During the twelve months ended December 31, 2018, we realized a net cash out-flow in our financing activities compared to a net inflow in 2017 primarily due to $297 million in net debt repayments in 2018 compared to $492 million in net debt issuance in 2017. In 2018, we repaid the entire balance of our $170 million 2015 Term Loan while in 2017, we issued $500 million 3.90% Senior Notes on May 25, 2017 to partially finance the 2017 Acquisition.

In addition to these activities, the change in our financing activities year-over-year was impacted by the net effect of the following:

- $66 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 that began in the first quarter of 2018;
- $7 million decrease in distributions paid to Class B units in 2018 as compared to 2017 due to the Class B Reduction;
- $136 million decrease in our ATM equity issuances in 2018 as compared to 2017; and
- $9 million increase in distributions paid to non-controlling interests due to higher revenues at PNGTS compared to 2017.

Capital spending

The Partnership's share in capital spending for maintenance of existing facilities and growth projects was as follows:

Year Ended December 31 (millions of dollars) (unaudited)	**2019**	**2018**	**2017**
Maintenance	**76**	60	63
Growth	**26**	7	3
Total[(a)]	**102**	67	66

(a) Total maintenance and growth capital expenditures as reflected in this table include AFUDC and amounts attributable to the Partnership's proportionate share of maintenance and growth capital expenditures of the Partnership's equity investments, which are not reflected in our total capital expenditures as presented in our consolidated statement of cash flows. Additionally, our proportionate share includes accrued capital expenditures during the period.

Year Ended December 31, 2019 Compared with the Year Ended December 31, 2018

Maintenance capital spending increased by $16 million in 2019 compared to 2018 mainly due to increases in major equipment overhauls and pipe integrity projects on GTN, as a result of higher transportation volumes of natural gas during the year. The higher maintenance projects costs were offset by lower compressor overhaul spending on Northern Border. Additionally, in 2018, PNGTS incurred costs on upgrading one of its existing meter communication systems to meet current commercial pressure obligations. No such project occurred in 2019.

Capital expenditures on growth projects increased by $19 million between 2018 and 2019 due to our continued spending on PXP and initial costs incurred on our GTN XPress, Iroquois' ExC and Westbrook XPress projects.

Year Ended December 31, 2018 Compared with the Year Ended December 31, 2017

Maintenance capital spending decreased by $3 million in 2018 compared to 2017 mainly due to decreases in pipeline integrity and communication equipment projects on GTN during 2017 in addition to a decrease in expenditures for remediation and automation projects on Northern Border in 2018 compared to 2017, partially offset by an increase in integrity and reliability projects on GTN.

Capital expenditures on growth projects increased by $4 million between 2017 and 2018 due to the PXP capital spending on PNGTS and an interconnect project on Northern Border.

Cash Flow Outlook

Operating Cash Flow Outlook

During the first quarter of 2020, the Partnership received or expects to receive the following distributions from our equity investments:

Northern Border declared its December 2019 distribution of $18 million on January 10, 2020, of which the Partnership received its 50 percent share or $9 million on January 31, 2020.

Northern Border declared its January 2020 distribution of $19 million on February 11, 2020, of which the Partnership will receive its 50 percent share or $9 million on February 28, 2020.

Great Lakes declared its fourth quarter 2019 distribution of $34 million on January 10, 2020, of which the Partnership received its 46.45 percent share or $16 million on January 31, 2020.

Iroquois declared its fourth quarter 2019 distribution of $27 million in February 2020, of which the Partnership will receive its 49.34 percent share or $14 million on March 30, 2020.

Investing Cash Flow Outlook

The Partnership expects to make a $10 million contribution in 2020 to Great Lakes to fund debt repayments which is consistent with prior years.

In 2020, our pipeline systems expect to invest approximately $152 million in maintenance capital for existing facilities, of which the Partnership's share will be $113 million. The Partnership's estimated capital maintenance costs do not include any costs related to our GTN XPress project (see further discussion below). Maintenance capital expenditures are added to our pipelines' respective rate bases and are expected to earn a return on and of capital over time through the regulatory rate-making process.

Our pipeline systems also expect to invest approximately $242 million in growth projects in 2020, of which the Partnership's share will be $187 million. Growth capital expenditures include $102 million of Phase I GTN XPress project costs which are reliability and horsepower replacement expenditures expected to be fully recoverable in GTN's recourse rates commencing in 2022, along with other ongoing growth projects as discussed in Part 1, Item 1. "Business — Recent Business Developments." GTN XPress is essentially a modernization program designed to replace and upgrade aging compressor infrastructure, increase reliability and integrate cutting-edge technology at sites along its route. This will help GTN reduce greenhouse gas emissions while ensuring the integrity of existing assets. The project will modernize the existing system and also grow capacity and, as such, is a hybrid project which is more like growth capital than maintenance capital.

Our maintenance and growth projects are funded from a combination of cash from operations and debt at both the asset and Partnership levels.

Our consolidated entities have commitments of $21 million as of December 31, 2019 in connection with various maintenance and general plant projects.

Please read Part 1, Item 1. "Business — Recent Business Developments" for more details regarding these projects.

Financing Cash Flow Outlook

On January 21, 2020, the board of directors of our General Partner declared the Partnership's fourth quarter 2019 cash distribution in the amount of $0.65 per common unit which was paid on February 14, 2020 to unitholders of record as of January 31, 2020. The total amount of cash distribution paid to common unitholders and General Partner was $47 million.

On January 21, 2020, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $8 million which was paid on February 14, 2020. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2019 less the threshold level of $20 million and the Class B Reduction. For 2020 and beyond, we expect the impact of Class B distribution on our cashflows to be significantly lower compared to the previous periods.

We currently intend to refinance GTN's $100 million 5.29% Unsecured Senior Notes due June 1, 2020, and Tuscarora's $23 million variable rate Unsecured Term Loan due August 21, 2020 in full or at an amount based on our preferred capitalization levels.

Please read Notes 8, 11, 14 and 15, Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules."

The majority of our growth projects as discussed in the Investing Cashflow Outlook section above is being financed through debt.

As of February 20, 2020, the available borrowing capacity on our Senior Credit Facility was $500 million.

Non-GAAP Financial Measures: EBITDA, Adjusted EBITDA, Distributable Cash Flow, Adjusted Earnings and Adjusted Earnings per Common Unit

EBITDA is an approximate measure of our operating profitability 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 it includes earnings from our equity investments.

Our Adjusted EBITDA excludes the 2018 impact of the following:

- Bison's contract termination proceeds amounting to $97 million recognized as revenue during the fourth quarter of 2018;
- the $537 million net long-lived asset impairment charge to Bison's current carrying value; and
- the $59 million impairment charge related to Tuscarora's goodwill.

We believe these items are significant but not reflective of our underlying operations. For the years ended December 31, 2019 and 2017, we do not have any similar adjustments in our Adjusted EBITDA. Accordingly, for the years ended December 31, 2019 and 2017 our EBITDA is the same as Adjusted EBITDA.

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 does not factor in any growth capital spending. It includes our Adjusted EBITDA plus:

- Distributions from our equity investments

less:

- Earnings from our equity investments,
- Allowance for funds used during construction (AFUDC),
- Interest expense,
- Current income taxes,
- Distributions to non-controlling interests,
- Distributions to TC Energy as former parent of PNGTS, and
- Maintenance capital expenditures.

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 two percent interest plus an amount equal to incentive distributions. Distributions allocable to the Class B units equal 30 percent of GTN's distributable cash flow for the year ended December 31, 2019, less $20 million (Class B Distribution) (2018 and 2017 — less $20 million).

For the year ended December 31, 2019, the Class B Distribution was 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 and will apply to any calendar year during which distributions payable in respect of common units for such calendar year do not equal or exceed $3.94 per common unit. The Class B Reduction was not applicable during 2017.

Adjusted earnings and Adjusted earnings per common unit exclude the 2018 impact of the $97 million of Bison contract termination proceeds and $596 million of impairment charges incurred during the year ended December 31, 2018 on our net income on a whole and per common unit basis, respectively.

Distributable cash flow, EBITDA, Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit 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 information 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 (Loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow

The following table presents a reconciliation of the non-GAAP financial measures of EBITDA, Adjusted EBITDA and Distributable Cash Flow, to the GAAP financial measure of net income.

Year Ended December 31 (unaudited) (millions of dollars)	**2019**	**2018**	**2017**
Net income (loss)	**298**	(165)	263
Add (Less):			
Interest expense[(a)]	**85**	94	84
Depreciation and amortization	**78**	97	97
Income tax expense (benefit)	**(1)**	1	1
EBITDA	**460**	27	445
Add:			
Impairment of goodwill	**—**	59	—
Impairment of long-lived assets	**—**	537	—
Bison contract terminations	**—**	(97)	—
ADJUSTED EBITDA	**460**	526	445
Add:			
Distributions from equity investments[(b)]			
Northern Border	**93**	85	82
Great Lakes	**55**	66	38
Iroquois[(c)]	**69**	56	41
	217	207	161
Less:			
Equity earnings:			
Northern Border	**(69)**	(68)	(67)
Great Lakes	**(51)**	(59)	(31)
Iroquois	**(40)**	(46)	(26)
	(160)	(173)	(124)
Less:			
AFUDC	**(2)**	(1)	—
Interest expense[(a)]	**(85)**	(94)	(84)
Current income taxes[(d)]	**(1)**	(1)	(1)
Distributions to non-controlling interests[(e)]	**(21)**	(20)	(14)
Distributions to TC Energy as PNGTS' former parent[(f)]	**—**	—	(2)
Maintenance capital expenditures[(g)]	**(56)**	(36)	(38)
	(165)	(152)	(139)
Total Distributable Cash Flow	**352**	408	343
General Partner distributions declared[(h)]	**(4)**	(4)	(18)
Distributions allocable to Class B units[(i)]	**(8)**	(13)	(15)
Distributable Cash Flow	**340**	391	310

(a) Interest expense as presented includes net realized loss related to the interest rates swaps and amortization of realized loss on PNGTS' derivative instruments (Refer to Notes 13 and 20, Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules").

(b) These amounts are calculated in accordance with the cash distribution policies of these entities. Distributions from each of our equity investments represent our respective share of these entities' 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 and includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $10 million for both years ended December 31, 2019 and December 31, 2018 and $8 million for the year ended December 31, 2017. In 2019, we also received an additional distribution of $15 million related to the increase in the cash Iroquois generated from its higher income in 2017 (post acquisition) and 2018. (Refer to Notes 5 and 7, Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules").

(d) Beginning the year ended December 31, 2019, we reduced our distributable cashflows based on the current income tax expense paid by PNGTS on its New Hampshire state taxes which approximates net cash paid during the current period. The change did not materially impact comparability to prior periods.

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

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

(g) The Partnership's maintenance capital expenditures include expenditures made to maintain, over the long term, our assets' operating capacity, system integrity and reliability. Accordingly, 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 on 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. Please read the Capital spending section for more information regarding the Partnership's total proportionate share of maintenance capital expenditures from our consolidated entities and equity investments.

(h) Distributions declared to the General Partner for the year ended December 31, 2019 did not include any incentive distributions (2018 — none; 2017 — $12 million).

(i) Distributions allocable to the Class B units is based on 30 percent of GTN's distributable cashflow during the current reporting period but declared and paid in the subsequent reporting period.

Year Ended December 31, 2019 Compared with the Year Ended December 31, 2018

Our EBITDA was $433 million higher in 2019 compared to 2018 due to the 2018 goodwill impairment of $59 million for Tuscarora and the long-lived asset impairment for Bison of $537 million, partially offset by the additional $97 million in revenue recognized for the Bison contract terminations. Our Adjusted EBITDA was lower by $66 million compared to 2018 as a result of higher equity earnings lower revenues and higher operating expenses Refer to "Results of Operations" for more details.

Our distributable cash flow decreased by $51 million for the year ended December 31, 2019 compared to the same period in 2018 due to the net effect of:

- lower Adjusted EBITDA from our Consolidated Subsidiaries primarily due to significantly lower revenues from Bison from being 100 percent fully contracted in 2018 to only approximately 40 percent in 2019 and an overall increase in our operating expenses as discussed in more detail in the Results of Operations Section;
- higher distributions from our equity investment in Northern Border primarily due to lower capital spending related to compressor station maintenance costs;
- lower distributions from Great Lakes resulting from decreased earnings and increased maintenance capital spending;
- additional distribution received from Iroquois due to the surplus cash accumulated from previous years' higher net income;
- higher maintenance capital expenditures related to major compression equipment overhauls and pipe integrity costs on GTN as a result of higher transportation volumes of natural gas;
- lower interest expense due to the full repayment of the $170 million Term Loan during the fourth quarter of 2018 and the partial repayment of borrowings under our Senior Credit Facility in the first quarter of 2019; and
- lower Class B allocation due to lower distributable cash flow generated by GTN.

Year Ended December 31, 2018 Compared with the Year Ended December 31, 2017

Our EBITDA was $418 million lower in 2018 compared to 2017 due to the goodwill impairment of $59 million for Tuscarora and the long-lived asset impairment for Bison of $537 million, partially offset by the additional $97 million in revenue recognized for the Bison contract terminations. Our Adjusted EBITDA was higher by $81 million compared to 2017 as a result of higher equity earnings and an overall increase in revenues in 2018. Refer to "Results of Operations" for more details.

Our distributable cash flow for the twelve months ended December 31, 2018 was $81 million higher compared to the twelve months ended December 31, 2017 due to the net effect of:

- higher Adjusted EBITDA from GTN, PNGTS and North Baja due to an increase in their revenues generated during the twelve months ended December 31, 2018 as described in the "Results of Operations" section;
- four quarters of distributions received from Iroquois during the twelve months ended December 31, 2018 compared to three quarters of distributions received during the previous period (ownership of 49.34 percent was effective June 1, 2017);
- higher financing costs as a result of additional debt incurred to partially finance the 2017 Acquisition;
- higher distributions from Great Lakes due to the increase in its revenue generated during the twelve months ended December 31, 2018 from higher short-term services sold during the year and the elimination of Great Lakes' revenue sharing mechanism that began in 2018 as part of Great Lakes rate settlement in 2017;
- higher distributable cash flow from Northern Border primarily due to an overall decrease in its system integrity maintenance capital expenditures in 2018;
- reduction in declared distributions which did not result in any IDR allocation to our General Partner during the current period; and
- lower distributions allocated to the Class B units as a result of the Class B Reduction, which was directly related to the reduction in distributions declared for the common units.

Contractual Obligations

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2019 included the following:

(unaudited) (millions of dollars)	Total	Payments Due by Period Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Year Ended December 31, 2019
TC PipeLines, LP						
Senior Credit Facility due 2021	—	—	—	—	—	—
2013 Term Loan Facility due 2022	450	—	450	—	—	3.52%
4.65% Senior Notes due 2021	350	—	350	—	—	4.65%[(a)]
4.375% Senior Notes due 2025	350	—	—	—	350	4.375%[(a)]
3.90% 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)]
PNGTS						
Revolving Credit Facility due 2023	39	—	—	39	—	3.47%
Transportation by others	1	1	—	—	—	
Tuscarora						
Unsecured Term Loan due 2020	23	23	—	—	—	3.39%
North Baja						
Unsecured Term Loan due 2021	50	—	50	—	—	3.34%
Partnership (TC PipeLines, LP and its subsidiaries)						
Interest on debt obligations[(b)]	430	78	123	87	142	
Operating leases	3	1	1	—	1	
	2,446	203	974	126	1,143	

(a) Fixed Rate debt

(b) Future interest payments on our fixed rate debt are based on scheduled maturities. Future interest payments on floating rate debt are estimated using debt levels and interest rates at December 31, 2019 and are therefore subject to change beyond 2019. Future interest payments on floating rate debt do not include potential obligation related to our interest rate swaps.

Additional information regarding the Partnership's debt and interest rate swaps can be found under Note 9 — Debt and Credit Facilities and Note 20- Fair Value measurements, respectively within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2019 included the following:

(unaudited) (millions of dollars)	Total	Payments Due by Period[(a)]			
		Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
$200 million Credit Agreement due 2024	115	—	—	115	—
7.50% Senior Notes due 2021	250	—	250	—	—
Interest payments on debt	50	22	21	7	—
Other commitments[(b)]	48	3	5	5	35
	463	25	276	127	35

(a) Represents 100 percent of Northern Border's contractual obligations.
(b) Future minimum payments for office space and rights-of-way commitments.

Northern Border has commitments of $9 million as of December 31, 2019 in connection with various pipeline, metering and overhaul projects.

Senior Notes

Northern Border's outstanding debt securities are senior unsecured notes. The indentures for the notes do not limit the amount of unsecured debt Northern Border may incur but do restrict secured indebtedness. At December 31, 2019, Northern Border was in compliance with all of its financial covenants.

Credit Agreement

Northern Border's credit agreement consists of a $200 million revolving credit facility. On October 1, 2019, the credit agreement was extended to mature on October 1, 2024. At December 31, 2019, $115 million was outstanding on this facility. At Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or LIBOR plus, in either case, an applicable margin that is based on Northern Border's long-term unsecured credit ratings. The interest rate on Northern Border's credit agreement at December 31, 2019 was 2.82 percent (2018 — 3.48 percent). At December 31, 2019, Northern Border was in compliance with all of its financial covenants.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations as of December 31, 2019 included the following:

(unaudited) (millions of dollars)	Total	Payments Due by Period[(a)]			
		Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
9.09% series Senior Notes due 2016 to 2021	20	10	10	—	—
6.95% series Senior Notes due 2020 to 2028	99	11	22	22	44
8.08% series Senior Notes due 2021 to 2030	100	—	20	20	60
Interest payments on debt	82	16	26	19	21
Right-of-way commitments	1	—	—	—	1
	302	37	78	61	126

(a) Represents 100 percent of Great Lakes' contractual obligations.

Great Lakes has commitments of $4 million as of December 31, 2019 in connection with compressor overhaul projects.

Long-Term Financing

All of Great Lakes' outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the senior note agreements, approximately $118 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2019 (2018 — $129 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2019.

Summary of Iroquois' Contractual Obligations

Iroquois' contractual obligations as of December 31, 2019 included the following:

(unaudited) (millions of dollars)	Total	Payments Due by Period[a] Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
4.12% series Senior Notes due 2034	140	—	—	—	140
4.07% series Senior Notes due 2030	150	—	—	—	150
6.10% series Senior Notes due 2027	29	3	8	8	10
Interest payments on debt	95	11	14	14	56
Transportation by others[b]	9	3	6	—	—
Operating leases	4	1	1	—	2
Pension contributions[c]	1	1	—	—	—
	428	19	29	22	358

(a) Represents 100 percent of Iroquois' contractual obligations.

(b) Rates are based on known 2020 levels. Beyond 2020, demand rates are subject to change.

(c) Pension contributions cannot be reasonably estimated by Iroquois beyond 2020.

Iroquois has commitments of $2.5 million as of December 31, 2019 relative to capital expenditures.

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 percent and the debt service coverage ratio must be at least 1.25 times for the four preceding quarters. At December 31, 2019, the debt/capitalization ratio was 52.1 percent and the debt service coverage ratio was 5.38 times, therefore, Iroquois was not restricted from making cash distributions.

Cash Distribution Policy of the Partnership

The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our General Partner after providing for Class B distributions based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its IDRs and two percent general partner interest and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The percentage interest distributions to the General Partner illustrated below that are in excess of its two percent general partner interest represent the IDRs.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distribution Common Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98%	2%
First Target Distribution	above $0.45 up to $0.81	98%	2%
Second Target Distribution	above $0.81 up to $0.88	85%	15%
Thereafter	above $0.88	75%	25%

Further information regarding our distributions can be found under Note 15 — Cash Distributions within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Distribution Policies of Our Pipeline Systems

Distributions of available cash are made to partners on a pro rata basis according to each partner's ownership percentage, approximately one month following the end of a quarter. Our pipeline systems' respective management committees determine the amounts and timing of cash distributions, where the amounts of such distributions are based on distributable cash flow as determined by a prescribed formula. Any changes to, or suspension of our pipeline systems' cash distribution policies requires the unanimous approval of their respective management committees.

GTN, Bison, PNGTS and North Baja's distribution policies require the pipelines to distribute 100 percent of distributable cash flow based on earnings before depreciation and amortization less AFUDC and maintenance capital expenditures. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

Tuscarora's distribution policy requires the distribution of 100 percent of distributable cash flow based on earnings before depreciation and amortization less debt repayment, AFUDC and maintenance capital expenditures. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

Iroquois and PNGTS distribute their available cash less any required reserves that are necessary to comply with debt covenants and/or appropriately conduct their respective businesses, as determined and approved by their management committees. While PNGTS' and Iroquois' debt repayments are not funded with capital calls to their owners, PNGTS and Iroquois have historically funded scheduled debt repayments by adjusting cash available for distribution, which effectively reduces the amount of cash available for distributions.

Northern Border's distribution policy requires Northern Border to distribute on a monthly basis, 100 percent of the distributable cash flow based on earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. Northern Border adopted certain changes related to equity contributions that defined minimum equity to total capitalization ratios to be used by the Northern Border management committee to determine the amount of required equity contributions, timing of the required contributions and for any shortfall due to the inability to refinance maturing debt to be funded by equity contributions.

Great Lakes' distribution policy requires the distribution of 100 percent of distributable cash flow based on earnings before income taxes, depreciation, AFUDC less capital expenditures and debt repayments not funded with cash calls to its partners. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

CRITICAL ACCOUNTING ESTIMATES

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 believe our critical accounting estimates discussed in the following paragraphs require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. These critical accounting estimates should be read in conjunction with our accounting policies summarized on Notes 2 and 3, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules."

Regulation

Our pipeline systems' accounting policies conform to *Accounting Standards Codification (ASC) 980 — Regulated Operations*. As a result, our pipeline systems record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Our pipeline systems consider several factors to evaluate their continued application of the provisions of ASC 980 such as potential deregulation of their pipelines; anticipated changes from cost-based rate-making to another form of regulation; increasing competition that limits their ability to recover costs; and regulatory actions that limit rate relief to a level insufficient to recover costs.

Certain assets that result from the rate-making process are reflected on the balance sheets of our pipeline systems. If it is determined that future recovery of these assets is no longer probable as a result of discontinuing application of ASC 980 or other regulatory actions, our pipeline systems would be required to write off the regulatory assets at that time. Due to the impairment recognized on Bison during the fourth quarter of 2018 (discussed in more detail below under "Long Lived Assets"), ASC 980 on Bison was discontinued as the future recovery of costs is no longer probable. The impact of ASC 980 discontinuance on Bison was immaterial to the consolidated results of the Partnership.

At December 31, 2019, the Partnership had no regulatory assets or regulatory liabilities reported as part of other current assets or accounts payable and accrued liabilities on the balance sheet, respectively.

As of December 31, 2019, our equity investees have regulatory assets amounting to $13 million (2018 — $14 million).

As of December 31, 2019, our equity investees have regulatory liabilities amounting to $39 million (2018 — $34 million).

At December 31, 2018, the Partnership had $2 million of regulatory assets reported as part of other current assets on the balance sheet and $2 million of regulatory liabilities reported on the balance sheet as part of accounts payable and accrued liabilities both representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers on a continued basis.

As of December 31, 2019, the Partnership had regulatory liabilities of $29 million largely related to estimated costs associated with future removal of transmission and gathering facilities or allowed by FERC to be collected in depreciation rates (also known as "negative salvage") (2018 — $27 million).

Impairment of Goodwill, Long-Lived Assets and Equity Investments

Goodwill

We test goodwill for impairment annually based on ASC 350 — Intangibles — Goodwill and Other, or more frequently if events or changes in circumstances lead us to believe it might be impaired. We can initially assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired and, if we conclude that there is not a greater than 50 percent likelihood that the fair value of the reporting unit is greater than its carrying value, will then perform the quantitative goodwill impairment test. We can also elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Partnership compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

We base these valuations on our projection of future cash flows which involves making estimates and assumptions about:

- discount rates and multiples;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of reporting unit, to the extent of the balance of goodwill.

2018 Impairment of Goodwill related to Tuscarora

In the fourth quarter of 2018, Tuscarora initiated its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its maximum rates. In connection with our annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, which included estimates related to discount rates and earnings multiples. In doing so, we incorporated the expected impact of Tuscarora's regulatory approach in response to the 2018 FERC Actions, in which it elected to make a limited NGA Section 4 filing to reduce its maximum rates and eliminate its deferred income tax balances previously used for rate setting. Additionally, for the year ended December 31, 2018, we considered the outcome of the 2019 Tuscarora Settlement with its customers in our overall conclusion.

Our analysis resulted in the estimated fair value of Tuscarora not exceeding its carrying value, including goodwill. The fair value was measured using a discounted cash flow approach whereby the expected cashflows were discounted using a risk adjusted discount rate to determine fair value.

As a result, we recorded a goodwill impairment charge amounting to $59 million against Tuscarora's goodwill balance of $82 million. The non-cash impairment charge was recorded in the Impairment of goodwill line on the Consolidated statement of operations and reduced our total consolidated goodwill balance from $130 million to $71 million.

2019 Update

In 2019, based on our qualitative analysis of Tuscarora and North Baja's current market conditions, which includes consideration of the potential qualitative impact of current year changes in the multiples and discount rate assumptions compared to multiples and discount rate assumptions used in the prior quantitative model, we believe there is a greater than 50 percent likelihood that Tuscarora and North Baja's estimated fair value exceeded their carrying value. As a result, at December 31, 2019, we have not identified an impairment on the $71 million of goodwill related to Tuscarora ($23 million) and North Baja ($48 million) acquisitions.

There is a risk that adverse changes in our key assumptions could result in an additional future impairment on Tuscarora's remaining goodwill of $23 million.

Long-Lived Assets

We assess our long-lived assets for impairment based on *ASC 360-10-35 Property, Plant and Equipment — Overall — Subsequent Measurement* when events or changes in circumstances indicate that the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows expected to be generated by that asset or asset group is less than the carrying value of the assets, an impairment charge is recognized for the excess of the carrying value over the fair value of the assets. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals as considered necessary.

Our management evaluates changes in our business and economic conditions and their implications for recoverability of our long-lived assets' carrying values when assessing these assets for impairments. The development of fair value estimates requires significant judgement in estimating future cash flows. In order to determine the estimated future cash flows, management must make certain estimates and assumptions, which include the same factors we consider in our annual impairment test of goodwill such as:

- discount rates and multiples;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

Any changes we make to these estimates and assumptions could materially affect future cash flows, which could result to the recognition of an impairment loss in our Consolidated statement of operations.

As of December 31, 2019, there were no indicators of impairment on our long-lived assets.

2018 Impairment on Bison's long-lived assets

During the fourth quarter of 2018, Bison received an unsolicited offer from a customer regarding the termination of its contract, which represented approximately 60 percent of Bison's contracted revenues. Bison and the customer mutually agreed to terms which included a cash payment to Bison of $95.4 million in December 2018 in exchange for the termination of all its contract obligations with Bison. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison in exchange for a lumpsum payment to Bison of approximately $2.0 million in December 2018. At the termination of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018 and the cash payments were used by the Partnership, together with other cash to pay in full its 2015 Term Loan Facility.

As disclosed under Part 1, Item 1. Business — Customers, Contracting and Demand section, natural gas is currently not flowing on Bison as a result of the relative cost advantage of WCSB and Bakken sourced gas versus Rockies production. Since its inception in January 2011, Bison has not experienced a decrease in its revenue as its original ten-year contracts included ship-or-pay terms that resulted in payment to Bison regardless of gas flows. In 2018, the Partnership expected a significant erosion on the cash flows Bison will generate in the future as a result of the advanced payments to Bison and related cancellation of the above contracts. The customer contract cancellations coupled with the persistence of unfavorable market conditions which have inhibited system flows prompted management to re-evaluate the carrying value of Bison's long-lived assets.

Although the Partnership continues to explore alternative transportation-related options for Bison, management is currently unable to quantify the future cash flows of a viable operating plan beyond the remaining customer contracts' expiry in January 2021, and accordingly the Partnership evaluated for impairment the carrying value of its property, plant and equipment on Bison at December 31, 2018. The Partnership will continue to maintain Bison to stand ready for redevelopment and has concluded that the remaining obligations of Bison, primarily in the form of property tax obligations and operating and maintenance costs, exceed the net cash inflows that management currently considers probable and estimable.

Based on these factors, during the fourth quarter of 2018, the Partnership recognized a non-cash impairment charge of $537 million relating to the remaining carrying value of Bison's property, plant and equipment after determining that it was no longer recoverable. The non-cash charge was recorded under the Impairment of long-lived assets line on the Consolidated statement of operations.

Equity Investments

We review our equity method investments when a significant event or change in circumstances has occurred that may have an adverse effect on the fair value of each investment. When such events or changes occur, we compare the estimated fair value to the carrying value of the related investment. We calculate the estimated fair value of an investment in an equity method investee using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows which are determined using the same factors we consider in our annual impairment test of goodwill such as:

- discount rates and multiples;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether an investment in an equity method investee has suffered impairment.

If the estimated fair value of an investment is less than its carrying value, we are required to determine if the decline in fair value is other than temporary. This determination considers the aforementioned valuation methodologies, the length of time and the extent to which fair value has been less than carrying value, the financial condition and near-term prospects of the investee, including any specific events which may influence the operations of the investee, the intent and ability of the holder to retain its investment in the investee for a period of time sufficient to allow for any anticipated recovery in market value, and other facts and circumstances. If the fair value of an investment is less than its carrying value and the decline in value is determined to be other than temporary, we record an impairment charge.

As of December 31, 2019, no impairment charge has been recorded related to our equity investments.

2018 Quantitative Assessment of Great Lakes' Fair Value

At December 31, 2018, the equity method goodwill balance related to Great Lakes amounted to $260 million (December 31, 2017 — $260 million). The equity method goodwill relates to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes and is the difference between the carrying value of our investment in Great Lakes and the underlying equity in Great Lakes' net assets.

During the fourth quarter of 2018, Great Lakes finalized its regulatory approach in response to the 2018 FERC Actions and elected to make a limited NGA section 4 filing with FERC to reduce its maximum rates and eliminate its tax allowance and deferred income tax balances previously used for rate setting. As a result of this action, and because the estimated fair value of our investment in Great Lakes exceeded its carrying value by less than ten percent in its 2017 valuation, we performed a quantitative test to determine if there was an other than temporary decline in Great Lakes' fair value. The assumptions we used in our analysis related to the estimated fair value of our equity investment in Great Lakes included expected results from its limited NGA Section 4 filing with FERC, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment, which includes estimates related to discount rates and earnings multiples. At December 31, 2018, we concluded the estimated fair value of our investment in Great Lakes exceeded its carrying value by more than ten percent.

2019 update

During the year ended December 31, 2019, Great Lakes' current market conditions and other factors relevant to Great Lakes' long-term financial performance have remained relatively stable. There is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in an additional future impairment of the carrying value of our investment in Great Lakes.

Contingencies

Our pipeline systems' accounting for contingencies covers a variety of business activities, including contingencies that could arise from legal and environmental liabilities. Our pipeline systems accrue for these contingencies when their assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with ASC 450 — Contingencies. Our pipeline systems base their estimates on currently available facts and their estimates of the ultimate outcome or resolution. Actual results may differ from our estimates or additional facts and circumstances cause us to revise our estimates resulting in an impact, positive or negative, on earnings and cash flow.

At December 31, 2019, 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.

RELATED PARTY TRANSACTIONS

Please read Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" and Note 17 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more information regarding related party transactions.

Item 7A. 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 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.

LIBOR, which is set to be phased out at the end of 2021, is used as a reference rate for certain of our financial instruments, including the Partnership's term loans, revolving credit facilities and the interest rate swap agreements that we use to manage our interest rate exposure. We are reviewing how the LIBOR phase-out will affect the Partnership, but we currently do not expect the impact to be material.

As of December 31, 2019, the Partnership's interest rate exposure resulted from our floating rate on North Baja's Unsecured Term Loan Facility, PNGTS' Revolving Credit Facility and Tuscarora's Unsecured Term Loan Facility, under which $112 million, or 6 percent, of our outstanding debt was subject to variability in LIBOR interest rates (December 31, 2018 — $168 million or 8 percent).

As of December 31, 2019, 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 December 31, 2019, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately $1 million.

As of December 31, 2019, $115 million, or 32 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 December 31, 2019, Northern Border's annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately $1 million.

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, as it currently does 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 and our pipeline systems enter into interest rate swaps and option agreements to mitigate the impact of changes in interest rates. For details regarding our current interest swaps and other agreements related to mitigation of impact on changes in interest rates, see Note 20- Fair Value Measurements within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

COMMODITY PRICE RISK

The Partnership is influenced by the same factors that influence our pipeline systems. None of our pipeline systems own any of the natural gas they transport; therefore, they do not assume any of the related natural gas commodity price risk with respect to transported natural gas volumes.

COUNTERPARTY CREDIT RISK AND LIQUIDITY RISK

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 has exposure to counterparty credit risk in the following areas:

- cash and cash equivalents;
- accounts receivable and other receivables; and
- the fair value of derivative assets.

At December 31, 2019, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired. Additionally, during year ended December 31, 2019 and at December 31, 2019, no customer accounted for more than 10 percent of our consolidated revenue and accounts receivable, respectively.

The Partnership and our pipeline systems have significant credit exposure to financial institutions as they hold cash deposits and 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, reviews accounts receivable regularly and, if needed, records allowances for doubtful accounts using the specific identification method. 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. Refer to Note 17 — Transactions with major customers within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more information. See also Part I, Item 1. "Business Customers, Contracting and Demand" section for more information on certain customers.

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. We manage our liquidity risk by continuously forecasting our cash flow on a regular basis to ensure we have adequate cash balances, cash flow from operations and credit facilities to meet our operating, financing and capital expenditure obligations when due, under both normal and stressed conditions. Refer to "Liquidity and Capital Resources" section for more information about our liquidity.

At December 31, 2019, the Partnership had a Senior Credit Facility of $500 million maturing in 2021 with no outstanding balance. At December 31, 2019, PNGTS has a $125 million Revolving Credit Facility maturing in 2023 and has an outstanding balance of $39 million and finally, at December 31, 2019, Northern Border had a committed revolving bank line of $200 million maturing in 2024 and $115 million was drawn. The Partnership's Senior Credit Facility, PNGTS'

Revolving Credit Facility and the Northern Border's Credit Facility have accordion features for additional capacity of $500 million, $50 million and $200 million respectively, subject to lender consent.

Item 8. Financial Statements and Supplementary Data

The financial statements required by this item are included in Part IV, Item 15 of this report on page F-1 and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15(e) under the 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 year covered by this annual 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 Securities Exchange Act of 1934, as amended (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 year ended December 31, 2019, there was no change in the Partnership's internal control over financial reporting that materially impacted or is reasonably likely to materially impact our internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Exchange Act. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment according to the above framework, management has concluded that our internal control over financial reporting was effective as of December 31, 2019 at providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. No material weaknesses were identified.

Our independent registered public accounting firm, KPMG LLP (KPMG), independently assessed the effectiveness of the Partnership's internal control over financial reporting. KPMG has issued an attestation report concurring with management's assessment, which is included starting on page F-2 of the financial statements included in this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The Partnership is a limited partnership and as such has no officers, directors or employees. Set forth below is certain information concerning the directors and officers of the General Partner who manage the operations of the Partnership as of February 20, 2020. Directors are appointed by the General Partner's sole stockholder to serve one-year terms or until their successors are appointed. All officers of the General Partner serve at the discretion of the board of directors of the General Partner which is an indirect wholly-owned subsidiary of TC Energy.

Name	Age	Position with General Partner
Stanley G. Chapman, III	54	Chair and Director
Jack F. Stark	69	Independent Director
Malyn K. Malquist	67	Independent Director
Walentin (Val) Mirosh	74	Independent Director
Nathaniel A. Brown	43	President, Principal Executive Officer and Director
Nadine E. Berge	47	Director
Sean M. Brett	54	Director
Janine M. Watson	50	Vice-President and General Manager
Alisa Williams	36	Vice-President, Taxation
Jon A. Dobson	53	Secretary
Burton D. Cole	45	Controller
William C. Morris	57	Principal Financial Officer, Vice-President and Treasurer

Mr. Chapman has served as a director and Chair of the Board of Directors of the General Partner since January 1, 2019. Mr. Chapman's principal occupation is Executive Vice-President and President, U.S. Natural Gas Pipelines of TC Energy, a position he has held since April 2017. He is responsible for all pipeline operations and commercial activities across TC Energy's FERC-regulated transmission and storage assets. Mr. Chapman joined TC Energy as part of its acquisition of the Columbia Pipeline Group (Columbia) in July 2016 and served as Senior Vice President and General Manager of TC Energy's FERC-regulated US natural gas pipeline business from July 2016 to April 2017. Prior to joining TC Energy, Mr. Chapman held several positions at Columbia from December 2011 to July 2016, most recently as Executive Vice-President and Chief Commercial Officer. Before joining Columbia, Mr. Chapman held various positions of increasing responsibility with El Paso Corp and Tenneco Energy and was responsible for various marketing and commercial operations, as well as supply, regulatory, business development and optimization activities. His industry knowledge, management experience and leadership skills are highly valuable in developing and implementing our business strategies and assessing accompanying risks.

Mr. Stark has served as a director and member of the audit and conflicts committee of the board of directors of the General Partner since July 1999. Mr. Stark currently serves as the Chief Financial Officer of Generate Capital Inc., a clean energy financing company. He previously served as Chief Financial Officer of Imergy Power Systems, formerly Deeya Energy, an energy storage systems company, from December 2013 to July 2016. Mr. Stark was the Chief Financial Officer of BrightSource Energy Inc., a provider of technology for use in large-scale solar thermal power plants, from May 2007 to November 2013 and Chief Financial Officer of Silicon Valley Bancshares, a diversified financial services provider, from April 2004 to May 2007. Prior to May 2007, Mr. Stark held chief financial officer positions at Itron Inc., Silicon Energy Corporation and GATX Capital as well as senior management roles at PG&E Corporation for more than 20 years. Mr. Stark previously served as a director, Chairman of the Board and member of the audit committee of the board of directors of Washington Gas Light Company, a regulated natural gas utility. He also serves on the board of directors of AltaGas Services (U.S.) Inc. (ASUS), a wholly-owned subsidiary of AltaGas Ltd., and AltaGas Utility Holdings (U.S.) Inc., a wholly owned subsidiary of ASUS. From November 2015 to October 2017, he served as a director of TerraForm

Power, Inc. and TerraForm Global, Inc., where he also served on the compensation and audit committees of both companies. Through his roles as chief financial officer of numerous companies, Mr. Stark brings valuable financial expertise and management experience, including extensive knowledge regarding financial operations, investor relations, finance, energy risk management, regulatory affairs and knowledge of the natural gas industry. Mr. Stark's prior audit committee experience further enhances his qualifications to serve as a member of our Board and our Audit Committee.

Mr. Malquist has served as a director, Chair of the audit committee and member of the conflicts committees of the board of directors of the General Partner since April 2011. Mr. Malquist is an executive with more than 30 years of experience serving in a variety of business, operations and financial roles. Mr. Malquist served on the board of directors and audit committee of Headwaters Incorporated (Headwaters), an NYSE-listed company that provides products, technologies and services in the light building products, heavy construction materials and energy industries, from January 2003 to May 2017, when Headwaters was acquired by Boral, Ltd. From September 2002 to March 2009, Mr. Malquist held various senior executive positions with Avista Corporation (Avista), an energy production, transmission and distribution company, including Senior Vice President from September 2002 to May 2006, Executive Vice President from May 2006 to March 2009, Chief Financial Officer from November 2002 to September 2008 and Treasurer from February 2004 to January 2006. Prior to his employment at Avista, Mr. Malquist held various positions at Sierra Pacific Resources, (electricity provider), including President, Chief Executive Officer and Chief Operating Officer from January 1998 to April 2000 and various Senior Vice-President positions from 1994 to 1998. Through his extensive prior management experience, including serving as chief financial officer and chief executive officer of various energy companies, Mr. Malquist brings extensive knowledge regarding financial operations, energy risk management and knowledge of the energy industry to the Board of Directors and the Audit Committee. His valuable management and financial expertise include an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis. In addition, Mr. Malquist's experience in the energy industry is beneficial to the service he provides to the Board of Directors.

Mr. Mirosh has served as a director and member of the audit and conflicts committees of the board of directors of the General Partner since September 2004. Mr. Mirosh's principal occupation is President of Mircan Resources Ltd., (private consulting company), a position he has held since 2009. From April 2008 to December 2009, he was Vice-President and Special Advisor to the President and Chief Operating Officer of NOVA Chemicals Corporation (NOVA), a commodity chemicals and plastics company. From July 2003 to April 2008, Mr. Mirosh was President of Olefins and Feedstocks, a division of NOVA. Prior to joining NOVA, Mr. Mirosh was a partner at Macleod Dixon law firm. Mr. Mirosh is also a director of Murphy Oil Corporation (an international oil and gas company). Mr. Mirosh's extensive experience in the natural gas transmission sector enhances the knowledge of the Board in this area of the industry. As a current and former executive and director of various companies, his breadth of experience is applicable to many of the matters routinely facing the Partnership. Moreover, Mr. Mirosh's experience and industry knowledge are complemented by an engineering educational background and legal experience, are beneficial to the Board of Directors and Audit Committee on a full range of business, financial, technical and professional matters.

Mr. Brown has served as President, Principal Executive Officer and a director of the General Partner since May 1, 2018. He previously served as Controller and Principal Financial Officer of the General Partner from May 2014 to May 2018. His principal occupation is Vice-President, U.S. Natural Gas Pipelines Financial Services of TransCanada USA Services Inc., an indirect wholly owned subsidiary of TC Energy ("TC USA"), a position he has held since February 2018. In this position, he is responsible for the accounting, financial reporting, planning and budgeting of TC Energy's U.S. natural gas pipelines. Mr. Brown also served as Director of Financial Services for TC Energy's U.S. Pipelines from May 2014 to February 2018 and Manager of Accounting for TC Energy's U.S. Pipelines West from November 2009 to May 2014. Prior to joining TC Energy, Mr. Brown spent eight years in public accounting, most recently as an audit manager for Grant Thornton LLP and Ernst & Young.

Ms. Berge has been a director of the General Partner since May 2018. Ms. Berge's principal occupation is Director, Corporate Compliance and Legal Operations with TC Energy, a position she has held since December 2014. Ms. Berge has served in several positions of increasing responsibility in the legal department since joining TC Energy in May 2005. Ms. Berge is responsible for directing the corporate compliance area across Canada, the US and Mexico, as well as leadership of operational matters for the TC Energy legal department in all three jurisdictions. Prior to joining TC Energy, Ms. Berge spent five years practicing law in the area of energy regulation. Ms. Berge brings valuable legal skills and experience to the Board of Directors.

Mr. Brett has served as a director of the General Partner since May 2018. Mr. Brett's principal occupation is Senior Vice-President, Power and Storage with TC Energy, a role he has held since January 2019 and in which he is responsible for all aspects of TC Energy's Power and Storage business, including strategy, commercial, business development, projects and operations. Mr. Brett joined TC Energy in March 1997 and held several positions of increasing responsibility prior to his current role, including Vice-President, Power and Storage from June 2018 to January 2019, Vice-President, Risk Management from August 2015 to June 2018 and Vice President and Treasurer from July 2010 to August 2015. Mr. Brett also previously served as Vice President, Commercial Operations of the General Partner from December 2009 to July 2010 and as Treasurer of the General Partner from January 2007 to December 2008. Mr. Brett's familiarity with the Partnership and TC Energy and his breadth of experience are highly valuable to the Board of Directors and are useful in assessing our business strategies and accompanying risks.

Ms. Watson has served as Vice-President and General Manager for the General Partner since October 2015. Her principal occupation is Director, LP Management & Pricing for TC Energy, a position she has held since October 2015. Ms. Watson joined TC Energy in 1997 and has served in progressively senior positions in the natural gas pipeline and energy business segments of TC Energy prior to her current position, most recently as Associate General Counsel, Energy Law. Prior to joining TC Energy, Ms. Watson practiced law at the Calgary office of McCarthy Tétrault and clerked at the Alberta Court of Appeal.

Ms. Williams has served as Vice-President, Taxation of the General Partner since July 2019. Her principal occupation is Director, U.S. Income Taxation of TC USA, in which role she leads the U.S. tax group and is responsible for providing tax administration, tax planning, regulatory and accounting support for TC Energy's U.S. subsidiaries. Ms. Williams joined TC Energy in July 2018 as the Manager of Tax Reporting until she was appointed Director, US Taxation in July 2019. Prior to joining TC Energy, Ms. Williams spent more than a decade in public accounting and private industry, most recently as Manager, Federal Income Tax for CITGO Petroleum Corporation from April 2018 to July 2018 and as Tax Manager, Income Tax Services for Enbridge Inc. (formerly Spectra Energy Corp) from May 2011 to April 2018.

Mr. Dobson has served as Secretary of the General Partner since May 2014, prior to which he served as Assistant Secretary of the General Partner from April 2012. Mr. Dobson's principal occupation is Director, U.S. Governance and Securities Law of TC USA and Corporate Secretary for TC Energy's U.S. subsidiaries. Prior to joining TC Energy in January 2011, Mr. Dobson spent 18 years practicing law in corporate and law firm positions, including Vice President and Assistant General Counsel of Nash Finch Company; Vice President, General Counsel and Secretary of BMC Industries, Inc.; and associate attorney at Lindquist & Vennum, PLLP.

Mr. Cole has served as Controller of the General Partner since July 2019. His principal occupation is Director, U.S. Accounting of TC USA, a position he has held since November 2018 and in which he leads the accounting and financial reporting group and supports the commercial, compliance and regulatory functions for TC Energy's U.S. natural gas pipelines. Prior to joining TC Energy, Mr. Cole spent more than two decades in public accounting and private industry positions, including Vice President, Chief Accounting Officer of Talos Energy Inc. from April 2018 to September 2018, Vice President, Finance of Speargrass Oil & Gas, LLC from April 2017 to March 2018 and various positions of increasing responsibility at Spectra Energy Corp, most recently as General Manager, Credit and Enterprise Risk from January 2014 to March 2017 and Corporate Controller from March 2011 to January 2014.

Mr. Morris has served as Vice-President, Principal Financial Officer and Treasurer of the General Partner since February 2018. Mr. Morris previously served as Vice President and Treasurer of the General Partner from November 2017 to February 2018 and as Treasurer of the General Partner from 2012 to November 2017. Mr. Morris' principal occupation is Director, Finance of TC Energy, a position he has held since November 2012. In this role, he is responsible for the development, execution and monitoring of TC Energy's financing strategy. Mr. Morris joined TC Energy in 1996 and has held various positions of increasing responsibility, including manager, Risk Management, and Director of Risk Management. Prior to joining TC Energy, Mr. Morris spent 12 years in the public accounting and banking industries.

GOVERNANCE MATTERS

We are a limited partnership and a 'controlled company' as that term is used in NYSE Rule 303A.00, because all of our voting shares are owned by the General Partner. As such, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

The NYSE listing standards require our principal executive officer to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. The most recent certification was provided to the NYSE on March 20, 2019.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the General Partner has determined that Malyn Malquist and Jack Stark are "audit committee financial experts," are "independent" and are "financially sophisticated" as defined under applicable SEC rules and NYSE Corporate Governance Standards. The board's affirmative determination for both Malyn Malquist and Jack Stark was based on their respective education and extensive experience as chief financial officers for corporations that presented a breadth and level of complexity of accounting issues that are generally comparable to those of the Partnership.

CODE OF ETHICS AND CORPORATE GOVERNANCE GUIDELINES

The Partnership believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. The directors, officers, employees and contractors of the General Partner are subject to TC Energy's Code of Business Ethics (COBE), which also has been adopted for the Partnership by our General Partner. Our COBE is published on our website at www.tcpipelineslp.com. If any substantive amendments are made to the COBE for senior officers or if any waivers are granted, the amendment or waiver will be published on the Partnership's website or filed in a report on Form 8-K.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how our Board of Directors should function and its position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at www.tcpipelineslp.com. If any amendments are made to the Corporate Governance Guidelines, the amendment will be published on the Partnership's website or filed in a report on Form 8-K.

AUDIT COMMITTEE

The General Partner of the Partnership has a separately designated audit committee consisting of three independent Board members. The members of the Audit Committee are Malyn Malquist, as Chair, Jack Stark and Walentin (Val) Mirosh. All members of the Audit Committee meet the criteria for independence and experience requirements of the NYSE and the Exchange Act. None of the Audit Committee members have participated in the preparation of the financial statements of the Partnership or any of its subsidiaries at any time during the past three years. In addition, all members of the Audit Committee are financially literate.

The Audit Committee has adopted a charter which specifically provides that it is responsible for the appointment, compensation, retention and oversight of the independent public accountants engaged in preparing and issuing the Partnership's audit report, that the Audit Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and for the committee to be responsible for establishing procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters, including procedures for the confidential, anonymous submission by employees of the General Partner of concerns regarding questionable accounting or auditing matters. The Audit Committee has adopted TC Energy's Ethics Help-Line in fulfillment of its responsibility to establish a confidential and anonymous whistle blowing process. The toll-free Ethics Help-Line number and the Audit Committee's charter are published on the Partnership's website at www.tcpipelineslp.com.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Board of Directors of our General Partner does not have a separate compensation committee, nor does it make any determination with respect to the amount of compensation to be paid to our executive officers.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of the General Partner meet at regularly scheduled executive sessions without management and non-independent directors. Jack Stark serves as the presiding director at those executive sessions. Persons wishing to communicate with the General Partner's independent directors may do so by writing in care of Secretary, Board of Directors, TC PipeLines, GP, Inc., 700 Louisiana Street, Suite 700, Houston, TX 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and are managed by the executive officers of our General Partner. We do not directly employ any of the individuals responsible for managing or operating our business. The executive officers of our General Partner are compensated directly by TC Energy.

The compensation policies and philosophy of TC Energy govern the types and amount of compensation granted to each of the named executive officers. Since these policies and philosophy are those of TC Energy, we refer you to a discussion of those items as set forth in the Executive Compensation section of the TC Energy "Management Information Circular" on the TC Energy website at www.tcenergy.com. The TC Energy "Management Information Circular" is prepared by TC Energy pursuant to applicable Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Securities Exchange Act of 1934, as amended; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our General Partner.

The Board of Directors of our General Partner does not have a separate compensation committee, nor does it make any determination with respect to the amount of compensation to be paid to our executive officers. The Board of our General Partner does have responsibility for evaluating and determining the reasonableness of costs allocated to us for managerial, administrative and operational support provided by TC Energy and its affiliates, including our General Partner. We reimburse TC Energy for a percentage of the compensation, including base salary and certain benefit expenses related to the officers of our General Partner and employees of TC Energy who perform services on our behalf. The total compensation that are allocable to us vary for each officer or employee performing services on our behalf and are based on the estimated amount of time an employee devotes to matters related to our business as compared to the amount of time such employee devotes to matters related to the business of TC Energy and its other affiliates. The Board of Directors of our General Partner specifically approves the percentage allocation to the Partnership of the compensation of the executive officers of the General Partner on an annual basis. Please read Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information regarding this arrangement.

Compensation Committee Report

Neither we, nor our General Partner, have a compensation committee. The board of directors of our General Partner has reviewed and discussed the Compensation Discussion and Analysis set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

The board of directors of TC PipeLines GP, Inc:

Nadine E. Berge
Sean M. Brett
Nathaniel A. Brown
Stanley G. Chapman, III
Malyn K. Malquist
Walentin (Val) Mirosh
Jack F. Stark

The following table summarizes the allocation percentages and amounts of the base salary and benefits charged to the Partnership in 2019, 2018 and 2017, as applicable, for the individuals serving as our President and Principal Executive Officers during 2019, Vice President, Principal Financial Officer and Treasurer and other executive officers of our General Partner for whom the salaries and benefits allocations to us exceeded $100,000.

Summary Compensation Table

Name and Principal Position	Year	Approximate Percentage of Time Devoted to the Partnership	Total Compensation allocated to the Partnership[(a)] (in US dollars)
Nathaniel A. Brown[(b)]	**2019**	**35%**	**177,755**
President and Principal Executive Officer	2018	35%	156,986
	2017	35%	121,737
William C. Morris[(c)(e)]	**2019**	**50%**	**172,165**
Vice-President, Principal Financial Officer and Treasurer	2018	50%	169,280
	2017	50%	163,891
Janine Watson[(e)]	**2019**	**50%**	**185,613**
Vice-President and General Manager	**2018**	50%	182,504
	2017	50%	170,244
Jon A. Dobson	**2019**	**60%**	**238,074**
Secretary	2018	60%	268,024
	2017	60%	253,793
Burton D. Cole[(d)]	**2019**	**35%**	**134,693**
Controller and Principal Accounting Officer	2018	—	—
	2017	—	—

(a) Amounts presented are based on the amount of reimbursement made by the Partnership to TC Energy representing base salary and benefits rate allocations from TC Energy to the Partnership for the year indicated and is based on the percentage of the applicable officer's time devoted to the Partnership. The benefit reimbursement is based on the total monthly or annual base salary allocated to the Partnership multiplied by a factor applicable to benefits of US and Canadian employees.

(b) Appointed as President and Principal Executive Officer effective May 1, 2018. The total compensation allocated to the Partnership in 2018 includes salary as Controller and Principal Financial Officer of the Partnership from January 1, 2018 - April 30, 2018.

(c) Appointed as Vice-President, Principal Financial Officer and Treasurer effective May 1, 2018. The total compensation allocated to the Partnership in 2018 includes salary as Vice-President and Treasurer of the Partnership from January 1, 2018 - April 30, 2018.

(d) Appointed as Controller, Principal Accounting Officer effective July 1, 2019. The total compensation presented here is his total compensation allocated to the Partnership in for the full year of 2019.

(e) Amounts presented have been converted to U.S. Dollars from Canadian dollars using the average exchange rate for the applicable year.

Independent Director Compensation[a]

For the year ended December 31, 2019 (in dollars)	Fees Earned or Paid in Cash	Deferred Share Unit Awards[b]	Total
Malyn K. Malquist[c]	95,000	80,000	175,000
Jack F. Stark[d]	95,000	80,000	175,000
Walentin (Val) Mirosh[e]	80,000	80,000	160,000

(a) Employee directors do not receive any additional compensation for serving on the board of directors of our General Partner; therefore, no amounts are shown for employee directors. Amounts paid as reimbursable business expenses to each director for attending board functions are not reflected in this table. Our General Partner does not consider the directors' reimbursable business expenses for attending board functions and other business expenses required to perform board duties to have a personal benefit and thus be considered a perquisite.

(b) Amounts presented reflect the compensation expense recognized pursuant to FASB ASC Topic 718 related to the deferred share units (DSUs) granted during 2019 under the DSU Plan. All of the DSUs granted to Messrs. Malquist, Stark and Mirosh were outstanding at December 31, 2019.

At December 31, 2019, Mr. Malquist, Mr. Stark and Mr. Mirosh held 19,880, 28,502 and 20,758 DSUs, respectively. The fair market value of the DSUs held by Mr. Malquist, Mr. Stark and Mr. Mirosh at December 31, 2019 was $840,930, $1,205,627 and $878,072, respectively. These amounts include distribution like payments credited to each independent director's DSU account equal to the distributions payable on the Partnership's common units multiplied by the number of DSU's in the director's account. In this regard, Mr. Malquist was credited 1,296 DSUs, Mr. Stark was credited 1,897 DSUs and Mr. Mirosh was credited 1,357 DSUs. All DSUs credited during 2019 were outstanding at December 31, 2019.

(c) Chair of the Audit Committee. Cash payments to Mr. Malquist include the $70,000 annual cash retainer, $15,000 Audit Committee Chair retainer and $10,000 of committee member retainer.

(d) Lead Independent Director and Chair of the Conflicts Committee. Cash payments to Mr. Stark include the $70,000 annual cash retainer, $15,000 Conflicts Committee Chair retainer and $10,000 of committee member retainer.

(e) Cash payments to Mr. Mirosh include the $70,000 annual cash retainer and $10,000 of committee member retainer.

Cash Compensation

In 2019, each director who was not an employee of TC Energy, the General Partner or its affiliates (independent director) was entitled to a directors' retainer fee of $150,000 per annum, of which $80,000 was automatically granted in DSUs (see Deferred Share Units section below). The independent director appointed as Lead Independent Director and Chair of the Conflicts Committee and the independent director appointed as Chair of the Audit Committee were each entitled to an additional fee of $15,000 per annum. Each independent director was also paid a committee member retainer of $5,000 for participating in each committee. The independent directors are reimbursed for out-of-pocket expenses incurred in the course of attending such meetings. All fees are paid by the Partnership on a quarterly basis. The independent directors are permitted to elect to receive any portion of their cash fees in the form of DSUs pursuant to the DSU Plan.

Deferred Share Units

The DSU Plan was established in 2007 with the first grant occurring in January 2008. The DSU Plan was amended and restated in its entirety effective as of January 1, 2014. In 2019, as part of the retainer fee, each independent director received quarterly automatic grants of DSUs valued at $20,000 each for a total annual grant value of $80,000.

At the time of grant, the value of a DSU is equal to the market value of one common unit of the Partnership at the time the DSU is credited to the independent director's account. The value of a DSU when redeemed is equivalent to the market value of one common unit of the Partnership at the time the redemption takes place. DSUs cannot be redeemed until the director ceases to be a member of the Board. Directors may redeem DSUs for cash or common units purchased in the open market through a broker at their option.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth information as of February 19, 2020 regarding the (i) beneficial ownership of our common units and shares of TC Energy by the General Partner's directors, the named executive officers and directors and executive officers as a group and (ii) beneficial ownership of our common units by all persons known by the General Partner to own beneficially at least five percent of our common units.

	Amount and Nature of Beneficial Ownership			
	TC PipeLines, LP		TC Energy Corporation	
Name and Business Address	**Number of Units[(a)]**	**Per cent of Class[(b)]**	**Common Shares**	**Per cent of class**
TransCan Northern Ltd[(c)] 450-1st Street SW Calgary, Alberta T2P 5H1	11,287,725	15.8	—	—
TC Pipelines GP, Inc.[(d)] 450-1st Street SW Calgary, Alberta T2P 5H1	5,797,106	8.1	—	—
ALPS Advisors, Inc.[(e)] 1290 Broadway, Suite 1100 Denver, CO 80203	6,466,808	9.07	—	—
First Trust Portfolios LP[(f)] 120 East Liberty Drive, Suite 400 Wheaton, Illinois 60187	6,649,340	9.33		
Energy Income Partners, LLC[(g)] 10 Wright Street Westport, Connecticut 06880	8,425,884	11.8		
Invesco Ltd.[(h)] 1555 Peachtree Street NE, Suite 1800 Atlanta, GA 30309	7,764,229	10.9		
Malyn K. Malquist[(i)]	21,194	*	—	—
Jack F. Stark[(j)]	29,242	*	—	—
Walentin (Val) Mirosh[(k)]	21,087	*	995	*
Stanley G. Chapman, III[(l)]	—	—	133,539	*
Nadine E. Berge[(m)]	—	—	273	*
Sean M. Brett[(n)]	—	—	78,796	*
Nathaniel A. Brown[(o)]	—	—	6,117	*
Burton D. Cole	—	—	—	—
Jon A. Dobson	—	—	—	*
William C. Morris[(p)]	—	—	20,277	*
Janine M. Watson[(q)]	—	—	129	*
Directors and Executive officers as a Group[(r)] (13 people)	71,523	*	240,126	*

(a) A total of 71,306,396 common units are issued and outstanding. For certain beneficial owners, the number of common units includes DSUs, which are a bookkeeping entry, equivalent to the value of a Partnership common unit, and do not entitle the holder to voting or other unitholder rights, other than the accrual of additional DSUs for the value of distributions. A director cannot redeem DSUs until the director ceases to be a member of the Board. Directors can then redeem their units for cash or common units.

(b) Any DSUs shall be deemed to be outstanding for the purpose of computing the percentage of outstanding common units owned by such person, but shall not be deemed to be outstanding for the purpose of computing the percentage of common units by any other person.

(c) TransCan Northern Ltd. is a wholly-owned indirect subsidiary of TC Energy.

(d) TC PipeLines GP, Inc. is a wholly-owned indirect subsidiary of TC Energy and also owns a two percent general partner interest of the Partnership.

(e) Based on a Schedule 13G/A filed with the SEC on February 7, 2020 by ALPS Advisors, Inc. In this Schedule 13G/A ALPS Advisors, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 6,466,808 common units.

(f) Based on Schedule 13G/A filed with the SEC on January 31, 2020 jointly by First Trust Portfolios LP, First Trust Advisors L.P. and The Charger Corporation. In this Schedule 13G, First Trust Advisors L.P. and The Charger Corporation have shared power to vote 6,649,340 common units and shared power to dispose of 6,655,236 common units, and First Trust Portfolios LP, First Trust Advisors L.P. and The Charger Corporation. disclaim beneficial ownership of all of said common units.

(g) Based on Schedule 13G/A filed with the SEC on February 14, 2020 by Energy Income Partners, LLC. In this Schedule 13G/A, Energy Income Partners LLC has shared power to vote and to dispose of the 8,425,884 common units.

(h) Based on a Schedule 13G/A filed with the SEC on February 7, 2020 by Invesco Ltd. In this Schedule 13G/A Invesco Ltd. disclaims beneficial ownership, and has shared power to vote 7,764,229 common units and shared power to dispose of 7,685,760 common units.

(i) Includes 20,194 DSUs and 1,000 common units of the Partnership.

(j) Includes 28,952 DSUs and 290 common units of the Partnership.

(k) Includes 21,087 DSUs and 995 TC Energy common shares.

(l) Includes 109,832 options exercisable within 60 days for TC Energy common shares and 23,707 TC Energy common shares held directly by Mr. Chapman.

(m) Includes 273 TC Energy common shares held in her Employee Share Savings Plan account.

(n) Includes 62,202 options exercisable within 60 days for TC Energy common shares, 3,500 TC Energy common shares held in his Employee Share Savings Plan accounts, 4,494 TC Energy common shares held directly and 8,600 TC Energy shares held by Mr. Brett's mother, of which he disclaims beneficial ownership.

(o) Includes 6,117 options exercisable within 60 days for TC Energy common shares.

(p) Includes 9,957 TC Energy common shares held in his Employee Share Savings Plan account and 10,320 TC Energy common shares held jointly with his spouse.

(q) Includes 129 TC Energy common shares held in her Employee Share Savings Plan account.

(r) Includes 70,233 DSUs and 1,290 common units of the Partnership, 21,196 TC Energy common shares held directly, 10,320 TC Energy common shares held with a spouse, 178,151 options exercisable within 60 days for TC Energy common shares, 8,600 TC Energy common shares owned by immediate family members of which beneficial ownership of such common shares is disclaimed, and 13,859 TC Energy common shares held in the TC Energy Employee Share Savings Plan.

* Less than one percent.

Item 13. Certain Relationships and Related Transactions, and Director Independence

As of February 19, 2020, subsidiaries of TC Energy own 17,084,831, or approximately 24 percent, of our outstanding common units, including 5,797,106 common units held by the General Partner. In addition, the General Partner owns 100 percent of our IDRs and a two percent general partner interest in the Partnership through which it manages and operates the Partnership. TC Energy also owns 100 percent of our Class B units. For more details regarding the Class B units, see Note 11 within Part IV, Item 15. "Exhibits and Financial Statement Schedules."

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our General Partner and its affiliates, which includes TC Energy, in connection with the ongoing operation and, if applicable, upon liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arms-length negotiations.

	Operational Stage
Distributions of average Cash to our General Partner and its affiliates	We generally make cash distributions of 98 percent to common unitholders, including our general partner with its affiliates as holders of an aggregate of 17,084,831 common units, and the remaining two percent to our General Partner. Additionally, the Class B units entitle TC Energy to receive an annual distribution based on 30 percent of GTN's annual distributions exceeding certain thresholds and adjustments, after the Class B reduction.
Payments to our General Partner and its affiliates	If distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 25 percent of the distributions above the highest target level. We refer to the rights to the increasing distributions as "incentive distribution rights." For further information about distributions, please read Part II Item 5. "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its General Partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
	Liquidation Stage
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances. The Class B units rank equally with common units upon liquidation.

Reimbursement of Operating and General and Administrative Expense

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 the conduct of 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. Total costs charged to the Partnership by the General Partner were $4 million for the year ended December 31, 2019.

Cash Management Programs

Great Lakes has a cash management agreement with TC Energy whereby its funds are pooled with other TC Energy affiliates. The agreement gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for its operating needs. At December 31, 2019 and 2018, Great Lakes had outstanding receivables from this arrangement amounting to $34 million and $36 million, respectively.

Transportation Agreements with Related Party

Refer to Note 18 within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Acquisitions

In the past, we have participated in several business acquisitions with TC Energy that were accounted for as transactions between entities under common control. For more details regarding the transactions' size, structure and terms, see Note 8 within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Operating Agreements with Our Pipeline Companies

Our pipeline systems are operated by TC Energy and its affiliates pursuant to operating agreements. Under these agreements, our pipeline systems are required to reimburse TC Energy for their costs including payroll, employee benefit costs, and other costs incurred on behalf of our pipeline systems. Costs for materials, services and other charges that are third-party charges are invoiced directly to each of our pipeline systems.

Total costs charged to our pipeline systems for the years ended December 31, 2019, 2018 and 2017 by TC Energy's subsidiaries and amounts payable to TC Energy's subsidiaries at December 31, 2019 and 2018 are summarized in Note 18 within Part IV, Item 15. "Exhibits and Financial Statement Schedules," which information is incorporated herein by reference.

Other Agreements

Our pipeline systems currently have interconnection, operational balancing agreements, transportation and exchange agreements and/or other inter-affiliate agreements with affiliates of TC Energy. In addition, each of our pipeline systems currently has other routine agreements with TC Energy that arise in the ordinary course of business, including agreements for services and other transportation and exchange agreements and interconnection and balancing agreements.

Relationship with our General Partner and TC Energy and Conflicts of Interest Resolution

Our Partnership Agreement contains specific provisions that address potential conflicts of interest between our General Partner and its affiliates, including TC Energy, on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our General Partner will resolve the conflict. Our General Partner may, but is not required to, seek the approval of such resolution from the conflicts committee of the board of directors of our General Partner (Special Approval), which is comprised of independent directors.

Any conflict of interest and any resolution of such conflict of interest shall be conclusively deemed fair and reasonable if such conflict of interest or resolution is approved by Special Approval:

- on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

The General Partner may also adopt a resolution or course of action that has not received Special Approval.

In acting for the Partnership, the General Partner is accountable to us and the unitholders as a fiduciary. Neither the Delaware Revised Uniform Limited Partnership Act (Delaware Act) nor case law defines with particularity the fiduciary duties owed by general partners to limited partners of a limited partnership. The Delaware Act does provide that Delaware limited partnerships may, in their partnership agreements, restrict or expand the fiduciary duties owed by a general partner to limited partners and the partnership.

In order to induce the General Partner to manage the business of the Partnership, the Partnership Agreement contains various provisions restricting the fiduciary duties that might otherwise be owed by the General Partner. The following is a summary of the material restrictions of the fiduciary duties owed by the General Partner to the limited partners:

- The Partnership Agreement permits the General Partner to make a number of decisions in its "sole discretion." This entitles the General Partner to consider only the interests and factors that it desires and it shall have no duty or obligation to give any consideration to any interest of, or factors affecting, the Partnership, its affiliates or any limited partner. Other provisions of the Partnership Agreement provide that the General Partner's actions must be made in its reasonable discretion.
- The Partnership Agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to the Partnership. In determining whether a transaction or resolution is "fair and reasonable" the General Partner may consider interests of all parties involved, including its own. Unless the General Partner has acted in bad faith, the action taken by the General Partner shall not constitute a breach of its fiduciary duty.

- The Partnership Agreement specifically provides that it shall not be a breach of the General Partner's fiduciary duty if its affiliates engage in business interests and activities in competition with, or in preference or to the exclusion of, the Partnership. Further, the General Partner and its affiliates have no obligation to present business opportunities to the Partnership.
- The Partnership Agreement provides that the General Partner and its officers and directors will not be liable for monetary damages to the Partnership, the limited partners or assignees for errors of judgment or for any acts or omissions if the General Partner and those other persons acted in good faith.

The Partnership is required to indemnify the General Partner and its officers, directors, employees, affiliates, partners, members, agents and trustees (collectively referred to hereafter as the General Partner and others), to the fullest extent permitted by law, against liabilities, costs and expenses incurred by the General Partner and others. This indemnification is required if the General Partner and others acted in good faith and in a manner, they reasonably believed to be in, or (in the case of a person other than the General Partner) not opposed to, the best interests of the Partnership. Indemnification is required for criminal proceedings if the General Partner and others had no reasonable cause to believe their conduct was unlawful. Please read Part III, Item 10. "Directors, Executive Officers and Corporate Governance" for additional information.

Director Independence

Please read Part III, Item 10. "Directors, Executive Officers and Corporate Governance" for information about the independence of our General Partner's board of directors and its committees, which information is incorporated herein by reference in its entirety.

Item 14. Principal Accountant Fees and Services

The following table sets forth, for the periods indicated, the fees billed by the principal accountants:

Year ended December 31 (thousands of dollars)	**2019**	**2018**	**2017**
Audit Fees	**1,185**	1,165[(a)]	861[(a)(b)]
Audit Related Fees	**—**	—	—
Tax Fees[(c)]	**—**	—	—
All Other Fees	**—**	—	—
Total	**1,185**	1,165	861

(a) $50 thousand of the 2018 audit fees related to ATM equity financing (2017 — $200 thousand).
(b) $65 thousand of the 2017 audit fees related to issuance of senior unsecured notes.
(c) The Partnership did not engage its external auditors for any tax or other services in 2019, 2018 or 2017.

AUDIT FEES

Audit fees include fees for the audit of annual GAAP financial statements, reviews of the related quarterly financial statements and related consents and comfort letters for documents filed with the SEC. Before our independent registered public accounting firm is engaged each year for annual audit and any non-audit services, these services and fees are reviewed and approved by our Audit Committee.

The Audit Committee has a policy to pre-approve the engagement fees and terms of all audit, audit-related, tax and other non-audit services provided to the Partnership by the independent registered public accounting firm. All of the fees in the table above were approved in accordance with this policy. As part of the pre-approval process, the Audit Committee also evaluates all non-audit services to be provided by the independent registered public accounting firm to ensure the provision of the non-audit services is compatible with maintaining the independence of the independent registered public accounting firm under applicable U.S. federal securities laws and stock exchange rules. Pre-approval is detailed as to the particular service or category of services and is subject to a specific budget or fee structure. The Audit Committee may delegate to one of its members the authority to pre-approve the engagement of the independent registered public accounting firm for permitted non-audit services, provided that such member is required to present the pre-approval of any permitted non-audit service to the full Audit Committee at its next meeting following any such pre-approval.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) *Financial Statements*

See "Index to Financial Statements" set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

The exhibit list required by this Item is incorporated by reference to the Exhibit Index that follows the financial statements files as a part of this report.

No.	Description
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*	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*	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).
3.2	Conformed Copy of Fourth Amended and Restated Agreement of Limited Partnership of TC Pipelines, LP (incorporating Amendment No. 1 thereto, entered into on February 4, 2020 and effective as of December 31, 2018).
4.1*	Indenture, dated as of June 17, 2011, between the Partnership and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed on June 17, 2011).
4.2*	Supplemental Indenture, dated as of June 17, 2011 relating to the issuance of $350,000,000 aggregate principal amount of 4.65% Senior Notes due 2021 (Incorporated by reference to Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed on June 17, 2011).
4.3*	Specimen of 4.65% Senior Notes due 2021 (Incorporated by reference to Exhibit A to the Supplemental Indenture filed as Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed on June 17, 2011).
4.4*	Form of indenture for senior debt securities (Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed on June 14, 2011).
4.5*	Second Supplemental Indenture, dated March 13, 2015, between TC PipeLines, LP and The Bank of New York Mellon (incorporated by reference from Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed March 13, 2015).
4.6*	Third Supplemental Indenture, dated as of May 25, 2017, relating to the issuance of $500,000,000 aggregate principal amount of 3.900% Senior Notes due 2027 (Incorporated by reference from Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed May 25, 2017).
4.7	Description of the Registrant's Securities.
10.1*	Third Amended and Restated Revolving Credit and Term Loan Agreement, dated as of November 10, 2016, by an among TC PipeLines, LP, the Lenders, and SunTrust Bank, as administrative agent for the Lenders (Incorporated by reference to Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 28, 2017).

No.	Description
10.1.1*	First Amendment to TC PipeLines, LP's Third Amended and Restated Revolving Credit Agreement, dated September 29, 2017 (Incorporated by reference from Exhibit 99.3 to TC PipeLines, LP's Form 8-K filed October 3, 2017).
10.2*	Term Loan Agreement, dated as of July 1, 2013, between TC PipeLines, LP and the lenders (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 3, 2013).
10.2.1*	First Amendment to Term Loan Agreement, dated as of November 10, 2016, by and among TC PipeLines, LP, the Required Lenders and SunTrust Bank, as administrative agent for the Lenders (Incorporated by reference to Exhibit 10.11.1 to TC PipeLines, LP's Form 10-K filed on February 28, 2017).
10.2.2*	Second Amendment to TC PipeLines, LP's July 1, 2013 Term Loan Agreement, dated September 29, 2017 (Incorporated by reference to Exhibit 99.1 to TC PipeLines, LP's Form 8-K filed October 3, 2017).
21.1	Subsidiaries of the Registrant.
23.1	Consent of KPMG LLP with respect to the financial statements of TC PipeLines, LP.
23.2	Consent of KPMG LLP with respect to the financial statements of Northern Border Pipeline Company.
23.3	Consent of KPMG LLP with respect to the financial statements of Great Lakes Gas Transmission Limited Partnership.
23.4	Consent of Blum, Shapiro & Company, P.C. with respect to the financial statements of Iroquois Gas Transmission System, L.P.
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial 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.
99.1	Amended Transportation Service Agreement FT18311 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 01, 2020.
99.2	Amended Transportation Service Agreement FT18229 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 01, 2020.
99.3	Amended Transportation Service Agreement FT17193 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, effective date November 01, 2020.
99.4	Amended Transportation Service Agreement FT18147 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2020.
99.5	Amended Transportation Service Agreement FT18150 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2020.
99.6	Amended Transportation Service Agreement FT17593 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2020.
99.7	Amended Transportation Service Agreement FT18659 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2020.
101	The following materials from TC PipeLines, LP's Annual Report on Form 10-K for the year ended December 31, 2019 formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statement of Cash Flows, (v) the Consolidated Statement of Changes in Partners' Equity, and (vi) the Notes to Consolidated Financial Statements (Audited)
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Indicates exhibits incorporated by reference.

\# Management contract or compensatory plan or arrangement.

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 20th day of February 2020.

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)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Stanley G. Chapman III Stanley G. Chapman III	Chair	February 20, 2020
/s/ Nathaniel A. Brown Nathaniel A. Brown	Principal Executive Officer and President	February 20, 2020
/s/ William C. Morris William C. Morris	Principal Financial Officer, Vice President and Treasurer	February 20, 2020
/s/ Nadine E. Berge Nadine E. Berge	Director	February 20, 2020
/s/ Sean M. Brett Sean M. Brett	Director	February 20, 2020
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 20, 2020
/s/ Jack F. Stark Jack F. Stark	Director	February 20, 2020
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 20, 2020

Index to financial statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Partners
TC Pipelines GP, Inc. General Partner of TC Pipelines, LP:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of TC Pipelines, LP (a Delaware limited partnership) and subsidiaries (the Partnership) as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). We also have audited the Partnership's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019 based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Partnership's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's consolidated financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A Partnership's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A Partnership's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Partnership; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Partnership's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Evaluation of the qualitative assessment over goodwill for the Tuscarora and North Baja reporting units

As discussed in Notes 2 and 4 to the consolidated financial statements, the Partnership performs goodwill impairment testing on an annual basis and whenever events and changes in circumstances indicate that the carrying value of goodwill might exceed the fair value of a reporting unit. The Partnership performed a qualitative assessment over goodwill for their identified reporting units to determine whether there was a greater than 50 percent likelihood that the fair value of the reporting unit was less than its carrying value. The goodwill balance at December 31, 2019 was $71 million and specifically the goodwill balances for the Tuscarora reporting unit and North Baja reporting unit were $23 million and $48 million, respectively.

We identified the determination and evaluation of the qualitative assessment over goodwill for the Tuscarora and North Baja reporting units as a critical audit matter. The qualitative assessments, specifically the market changes associated with the multiples and discount rates, required complex auditor judgment as minor changes to those considerations could have a significant impact on the assessment of the carrying value of goodwill.

The primary procedures we performed to address the critical audit matter included the following. We tested certain internal controls over the Partnership's goodwill impairment process, including controls related to the development of the multiples and discount rates used in the qualitative assessment. We involved a valuation professional with specialized skill and knowledge who assisted in:

- Evaluating the Partnership's determination of multiples by comparing to independently observed recent market transactions of comparable assets and using publicly available market data for comparable entities.
- Evaluating the Partnership's determination of applicable discount rates by comparing management's selected discount rate to a discount rate range that was independently developed using publicly available market data for comparable companies.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2011.

Houston, TX
February 20, 2020

TC PIPELINES, LP

Consolidated balance sheets

December 31 (millions of dollars)	2019	2018
ASSETS		
Current Assets		
Cash and cash equivalents	**83**	33
Accounts receivable and other *(Note 21)*	**43**	48
Distribution receivable from Iroquois *(Note 5)*	**14**	—
Inventories	**10**	8
Other	**6**	8
	156	97
Equity investments *(Note 5)*	**1,098**	1,196
Property, plant and equipment, net *(Note 7)*	**1,528**	1,529
Goodwill *(Note 4)*	**71**	71
Other assets	**—**	6
TOTAL ASSETS	**2,853**	2,899
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**28**	36
Accounts payable to affiliates *(Note 18)*	**8**	6
Accrued interest	**11**	12
Current portion of long-term debt *(Note 9)*	**123**	36
	170	90
Long-term debt *(Note 9)*	**1,880**	2,072
Deferred state income taxes *(Note 2)*	**7**	9
Other liabilities *(Note 10)*	**36**	29
	2,093	2,200
Partners' Equity *(Note 11)*		
Common units	**544**	462
Class B units	**103**	108
General partner	**14**	13
Accumulated other comprehensive income (loss) (AOCI) *(Note 12)*	**(5)**	8
Controlling interests	**656**	591
Non-controlling interest	**104**	108
	760	699
TOTAL LIABILITIES AND PARTNERS' EQUITY	**2,853**	2,899

Contingencies *(Note 22)*
Variable Interest Entities *(Note 23)*
Subsequent Events *(Note 24)*

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

TC PIPELINES, LP

Consolidated statements of operations

Year ended December 31 (millions of dollars except per common unit amounts)	**2019**	**2018**	**2017**
Transmission revenues, net *(Note 6)*	**403**	549	422
Equity earnings *(Note 5)*	**160**	173	124
Impairment of long-lived assets *(Note 7)*	**—**	(537)	—
Impairment of goodwill *(Note 4)*	**—**	(59)	—
Operation and maintenance expenses	**(71)**	(67)	(67)
Property taxes	**(26)**	(28)	(28)
General and administrative	**(8)**	(6)	(8)
Depreciation	**(78)**	(97)	(97)
Financial charges and other *(Note 13)*	**(83)**	(92)	(82)
Net income (loss) before taxes	**297**	(164)	264
Income taxes *(Note 2)*	**1**	(1)	(1)
Net Income (loss)	**298**	(165)	263
Net income attributable to non-controlling interests	**18**	17	11
Net income (loss) attributable to controlling interests	**280**	(182)	252
Net income (loss) attributable to controlling interest allocation *(Note 14)*			
Common units	**267**	(191)	219
General Partner	**5**	(4)	16
TC Energy and its subsidiaries	**8**	13	17
	280	(182)	252
Net income (loss) per common unit *(Note 14)* — basic and diluted	**$3.74**	$(2.68)	$3.16
Weighted average common units outstanding *(millions)* — basic and diluted	**71.3**	71.3	69.2
Common units outstanding, end of year *(millions)*	**71.3**	71.3	70.6

TC PIPELINES, LP

Consolidated statements of comprehensive income (loss)

Year ended December 31 (millions of dollars)	**2019**	**2018**	**2017**
Net income (loss)	**298**	(165)	263
Other comprehensive income (loss)			
Change in fair value of cash flow hedges *(Notes 12 and 20)*	**(13)**	(2)	5
Reclassification to net income of gains and losses on cash flow hedges *(Notes 12 and 20)*	**(1)**	5	—
Amortization of realized loss on derivative instrument *(Notes 12 and 20)*	**—**	1	1
Other comprehensive income (loss) on equity investments *(Note 12)*	**1**	(1)	1
Comprehensive income (loss)	**285**	(162)	270
Comprehensive income attributable to non-controlling interests	**18**	17	11
Comprehensive income (loss) attributable to controlling interests	**267**	(179)	259

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

TC PIPELINES, LP

Consolidated statements of cash flows

Year ended December 31 (millions of dollars)	**2019**	**2018**	**2017**
Cash Generated from Operations			
Net income (loss)	**298**	(165)	263
Depreciation	**78**	97	97
Impairment of long-lived assets *(Note 7)*	**—**	537	—
Impairment of goodwill *(Note 4)*	**—**	59	—
Amortization of debt issue costs reported as interest expense *(Note 13)*	**2**	2	2
Amortization of realized loss on derivative instrument *(Note 20)*	**—**	1	1
Equity earnings from equity investments *(Note 5)*	**(160)**	(173)	(124)
Distributions received from operating activities of equity investments *(Note 5)*	**200**	188	140
Change in other long-term liabilities	**(1)**	(2)	—
Equity allowance for funds used during construction	**(2)**	(1)	(1)
Change in operating working capital *(Note 16)*	**(3)**	(3)	(2)
	412	540	376
Investing Activities			
Investment in Great Lakes *(Note 5)*	**(10)**	(9)	(9)
Investment in Iroquois *(Note 5)*	**(4)**	—	—
Investment in Northern Border *(Note 5)*	**—**	—	(83)
Distribution received from Northern Border as return of investment *(Note 5)*	**50**	—	—
Distribution received from Iroquois as return of investment *(Note 5)*	**8**	10	5
Acquisition of a 49.34 percent in Iroquois and an additional 11.81 percent in PNGTS *(Note 8)*	**—**	—	(646)
Capital expenditures	**(75)**	(40)	(29)
Other	**(1)**	4	1
	(32)	(35)	(761)
Financing Activities			
Distributions paid *(Note 15)*	**(189)**	(218)	(284)
Distributions paid to Class B units *(Notes 11 and 15)*	**(13)**	(15)	(22)
Distributions paid to non-controlling interests	**(22)**	(14)	(5)
Distributions paid to former parent of PNGTS	**—**	—	(1)
Common unit issuance, net *(Note 11)*	**—**	40	176
Long-term debt issued, net of discount *(Note 9)*	**30**	219	802
Long-term debt repaid *(Note 9)*	**(136)**	(516)	(310)
Debt issuance costs	**—**	(1)	(2)
	(330)	(505)	354
Increase/(decrease) in cash and cash equivalents	**50**	—	(31)
Cash and cash equivalents, beginning of year	**33**	33	64
Cash and cash equivalents, end of year	**83**	33	33
Interest payments paid	**87**	94	79
State income taxes paid	**2**	1	2
Supplemental information about non-cash investing and financing activities			
Accrued capital expenditures	**12**	7	9

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

TC PIPELINES, LP

Consolidated statement of changes in partners' equity

	Limited Partners Common Units		Partners Class B Units		General Partner	Accumulated Other Comprehensive Income (Loss)[a]	Non-Controlling Interest	PNGTS[b]	Total Equity
	(millions of units)	(millions of dollars)	(millions of units)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of dollars)
Partners' Equity at December 31, 2016[c]	67.4	1,002	1.9	117	27	(2)	97	31	1,272
Net income	—	219	—	15	16	—	11	2	263
Other comprehensive income	—	—	—	—	—	7	—	—	7
ATM equity issuances, net *(Note 11)*	3.2	173	—	—	3	—	—	—	176
Reclassification of common units no longer subject to rescission *(Note 11)*	—	81	—	—	2	—	—	—	83
Acquisition of interests in PNGTS and Iroquois *(Note 8)*	—	(383)	—	—	(8)	—	—	(32)	(423)
Distributions	—	(268)	—	(22)	(16)	—	(3)	(1)	(310)
Partners' Equity at December 31, 2017	70.6	824	1.9	110	24	5	105	—	1,068
Net income (loss)	—	(191)	—	13	(4)	—	17	—	(165)
Other comprehensive income	—	—	—	—	—	3	—	—	3
ATM equity issuances, net *(Note 11)*	0.7	39	—	—	1	—	—	—	40
Distributions	—	(210)	—	(15)	(8)	—	(14)	—	(247)
Partners' Equity at December 31, 2018	71.3	462	1.9	108	13	8	108	—	699
Net income	**—**	**267**	**—**	**8**	**5**	**—**	**18**	**—**	**298**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**(13)**	**—**	**—**	**(13)**
Distributions	**—**	**(185)**	**—**	**(13)**	**(4)**	**—**	**(22)**	**—**	**(224)**
Partners' Equity at December 31, 2019	**71.3**	**544**	**1.9**	**103**	**14**	**(5)**	**104**	**—**	**760**

(a) Gains (losses) related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $2 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.
(b) Equity of Former Parent of PNGTS.
(c) Recast to consolidate PNGTS (Refer to Notes 2 and 8).

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

Notes to consolidated financial statements

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 TC Energy Corporation (TC Energy Corporation together with its subsidiaries collectively referred to herein as TC Energy), to acquire, own and participate in the management of energy infrastructure assets in North America.

At December 31, 2018, the Partnership owned its pipeline assets through an intermediate general partnership, TC PipeLines Intermediate GP, LLC (Intermediate GP) and three intermediate limited partnerships (ILPs), TC GL Intermediate Limited Partnership, TC PipeLines Intermediate Limited Partnership and TC Tuscarora Intermediate Limited Partnership. During the fourth quarter of 2019, the Partnership initiated the dissolution of the ILPs and Intermediate GP. Effective October 31, 2019, the Intermediate GP and ILPs transferred 100 percent of the ownership of their pipeline assets to the Partnership. As a result, the Partnership owns its pipeline assets directly which creates a more efficient partnership structure with no economic impact to the general and limited partners of the Partnership.

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends between an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100 percent
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can transport natural gas from the Powder River Basin to Midwest markets.	100 percent
North Baja	86 miles	Extends between an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100 percent
Tuscarora	305 miles	Extends between the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100 percent
Northern Border	1,412 miles	Extends between the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Bakken, the Williston Basin and Rocky Mountain area for deliveries to the Midwest. ONEOK Northern Border Pipeline Company Holdings LLC owns the remaining 50 percent of Northern Border.	50 percent
PNGTS	295 miles	Connects with the TQM at the Canadian border to deliver natural gas to customers in the U.S. northeast. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS. The 295-mile pipeline includes 107 miles of jointly owned pipeline facilities (the Joint Facilities) with MNE. The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32 percent of the undivided ownership interest based on contractually agreed upon percentages. The Joint Facilities are maintained and operated by MNOC, a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.	61.71 percent
Great Lakes	2,115 miles	Connects with the TC Energy Mainline at the Canadian border near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TC Energy owns the remaining 53.55 percent of Great Lakes.	46.45 percent
Iroquois	416 miles	Extends from the TC Energy Mainline system near Waddington, New York to deliver natural gas to customers in the U.S. northeast. The remaining 50.66 percent is owned by: TC Energy (0.66 percent), Dominion Energy (50 percent). Iroquois is maintained and operated by a subsidiary of Iroquois.	49.34 percent

The Partnership is managed by its General Partner, TC PipeLines GP, Inc. (General Partner), an indirect wholly-owned subsidiary of TC Energy. The General Partner provides management and operating services to the Partnership and is reimbursed for its costs and expenses. The General Partner owns 5,797,106 of our common units, 100 percent of our Incentive Distribution Rights (IDRs) and a two percent general partner interest in the Partnership at December 31, 2019. TC Energy also indirectly holds an additional 11,287,725 common units, for a total ownership of approximately 24 percent of our outstanding common units and 100 percent of our Classs B units at December 31, 2019 (Refer to Note 11).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated financial statements and related notes have been prepared in accordance with U.S. generally accepted accounting principles (GAAP) and amounts are stated in U.S. dollars. The financial statements and notes present the financial position of the Partnership as of December 31, 2019 and 2018 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2019, 2018 and 2017.

(a) 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 TC Energy are considered common control transactions. When businesses that will be consolidated are acquired from TC Energy by the Partnership, the historical financial statements are required to be recast, with the exception of net income (loss) per common unit, to include the acquired entities for all periods presented.

When the Partnership acquires an asset or an investment from TC Energy, 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.

On June 1, 2017, the Partnership acquired from a subsidiary of TC Energy an additional 11.81 percent interest in PNGTS, resulting in the Partnership owning 61.71 percent in PNGTS (Refer to Note 8). This acquisition was accounted for as transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of PNGTS were recorded at TC Energy's carrying value.

Also, on June 1, 2017, the Partnership acquired from subsidiaries of TC Energy a 49.34 percent interest in Iroquois (Refer to Note 8). Accordingly, this transaction was accounted for as a transaction between entities under common control, similar to a pooling of interest, whereby the equity investment in Iroquois was recorded at TC Energy's carrying value and was accounted for prospectively.

(b) 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.

(c) Cash and Cash Equivalents

The Partnership's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

(d) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method.

(e) Natural gas imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and interconnecting parties at current index prices. Imbalances are settled in kind, subject to the terms of the pipelines' tariff.

Imbalances due from others are reported as trade accounts receivable or accounts receivable from affiliates under the caption accounts receivable and other on the balance sheets. Imbalances owed to others are reported on the balance sheets as accounts payable and accrued liabilities and accounts payable to affiliates. The determination of the asset or liability classification is based on the net position of the customer. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(f) Inventories

Inventories primarily consist of materials and supplies and are carried at the lower of weighted average cost and net realizable value.

(g) Property, plant and Equipment

Property, plant and equipment are stated at original cost. Costs of restoring the land above and around the pipeline are capitalized to pipeline facilities and depreciated over the remaining life of the related pipeline facilities. Pipeline facilities and compression equipment have an estimated useful life of 20 to 77 years and metering and other equipment ranges from five to 77 years. Depreciation of our subsidiaries' assets is based on rates approved by FERC from the pipelines' last rate proceeding and is calculated on a straight-line composite basis over the assets' estimated useful lives. Under the composite method, assets with similar lives and characteristics are grouped and depreciated as one asset. Repair and maintenance costs are expensed as incurred. Costs that are considered a betterment are capitalized.

The Partnership's subsidiaries capitalize a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC), calculated based on the average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of property, plant and equipment on the balance sheets. Amounts included in construction work in progress are not depreciated until transferred into service.

(h) Impairment of Equity Method Investments

We review our equity method investments when a significant event or change in circumstances has occurred that may have an adverse effect on the fair value of each investment. When such events or changes occur, we compare the estimated fair value to the carrying value of the related investment. We calculate the estimated fair value of an investment in an equity method investee using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows, which is dependent on internal forecasts, estimates of the long-term rate of growth for the investee, estimates of the useful life over which cash flows will occur, and determination of weighted average cost of capital. The estimates used to calculate the fair value of an investee can change from year to year based on operating results and market conditions. Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether an investment in an equity method investee has suffered an impairment.

If the estimated fair value of an investment is less than its carrying value, we are required to determine if the decline in fair value is other than temporary. This determination considers the aforementioned valuation methodologies, the length of time and the extent to which fair value has been less than carrying value, the financial condition and near-term prospects of the investee, including any specific events which may influence the operations of the investee, the intent and ability of the holder to retain its investment in the investee for a period of time sufficient to allow for any anticipated recovery in market value, and other facts and circumstances. If the fair value of an investment is less than its carrying value and the decline in value is determined to be other than temporary, we record an impairment charge.

(i) Impairment of Long-lived Assets

The Partnership reviews long-lived assets, such as property, plant and equipment for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

(j) Partners' Equity

Costs incurred in connection with the issuance of units are deducted from the proceeds received.

(k) Revenue Recognition

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 utilizes the practical expedient of recognizing revenue as invoiced. 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.

The Partnership's pipeline systems are subject to Federal Energy Regulatory Commission (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. Refer to Note 6 for detailed disclosures regarding the Partnership's revenues.

(l) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective interest rate method over the term of the related debt. Consistent with debt discount, debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities. The amortization of debt issuance costs is reported as interest expense.

(m) Income Taxes

U.S. federal and certain state income taxes are the responsibility of the partners and are not reflected in these consolidated financial statements. The tax effect of the Partnership's activities accrues to its partners. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statement of operations, is includable in the U.S. federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined because all information regarding each partner's tax attributes related to the partnership is not available.

In instances where the Partnership is subject to state income taxes, the asset-liability method is used to account for taxes. This method requires the recognition of deferred tax assets and liabilities for future tax consequences attributable to the differences between the financial statement carrying amount of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are classified as non-current on our balance sheet.

State Income Taxes on PNGTS

The Partnership's income taxes relate to business profits tax (BPT) levied at the partnership (PNGTS) level by the state of New Hampshire (NH). 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 December 31, 2019, 2018 and 2017 relate primarily to utility plant. The NH BPT effective tax rate was 2.6 percent for the year ended December 31, 2019 (2018 — 3.5 percent, 2017 — 3.8 percent) and was applied to PNGTS' taxable income.

The state income taxes of PNGTS are broken out as follows:

Year ended December 31 (millions of dollars)	2019	2018	2017
State income tax benefit (expense)			
Current	**(1)**	(2)	(1)
Deferred	**2**	1	—
	1	(1)	(1)

(n) Acquisitions and Goodwill

The Partnership accounts for business acquisitions from third parties using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. The excess of the purchase price over the fair value of net assets acquired is attributed to goodwill.

Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if any indicators of impairment are evident. The Partnership can initially assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired and if the Partnership concludes there is not a greater than 50 percent likelihood that the fair value of the reporting unit is greater than its carrying value, the Partnership will then perform the quantitative goodwill impairment test. The Partnership can also elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Partnership compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

We calculate the estimated fair value of the reporting unit using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows, which is dependent on internal forecasts, estimates of the long-term rate of growth for of the reporting unit, estimates of the useful life over which cash flows will occur, and a determination of weighted average cost of capital. The estimates used to calculate the fair value of the reporting unit can change from year to year based on operating results and market conditions. Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether the goodwill in the reporting unit has suffered an impairment.

The Partnership accounts for business acquisitions between itself and TC Energy, also known as "dropdowns," as transactions between entities under common control. Using this approach, the assets and liabilities of the acquired entities are recorded at TC Energy's carrying value. In the event recasting is required, the Partnership's historical financial information will be recast, with the exception of net income (loss) per common unit, to include the acquired entities for all periods presented. If the fair market value paid for the acquired entities is greater than the recorded net assets of the acquired entities, the excess purchase price paid is recorded as a reduction in Partners' Equity. Similarly, if the fair market value paid for the acquired entities is less than the recorded net assets of the acquired entities, the excess of assets acquired is recorded as an increase in Partners' Equity.

(o) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable, certain accrued expenses and short-term debt, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments and the interest rate swap agreements, fair value is estimated based upon market values (if applicable) or on the current interest rates available to us for debt with similar terms and remaining maturities. Judgment is required in developing these estimates.

(p) Derivative Financial Instruments and Hedging Activities

The Partnership recognizes all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

The Partnership only enters into derivative contracts that it intends to designate as a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). In a cash flow hedging relationship, the change in the fair value of the hedging derivative is reported as a component of other comprehensive income and reclassified into earnings as part of "financial charges and other" line in the Consolidated Statement of Operations in the same period or periods during which the hedged transaction affects earnings or is reclassified immediately to net income when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In some instances, the derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

(q) Asset Retirement Obligation

The Partnership recognizes the fair value of a liability for asset retirement obligations in the period in which it is incurred, when a legal obligation exists, and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system and intends to do so as long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system's assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2019 and 2018.

(r) Government Regulation

The Partnership's subsidiaries are subject to regulation by FERC. Under regulatory accounting principles, certain assets or liabilities that result from the regulated rate-making process may be recorded that would not be recorded under GAAP for non-regulated entities. The timing of recognition of certain revenues and expenses in our regulated business may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and rates. The Partnership regularly evaluates the continued applicability of regulatory accounting, considering such factors as regulatory changes, the impact of competition, and the ability to recover regulatory assets. At December 31, 2019, the Partnership had nil amount of regulatory assets reported as part of other current assets in the balance sheet and nil amount of regulatory liabilities reported on the balance sheet as part of accounts payable and accrued liabilities. At December 31, 2018, the Partnership had regulatory assets amounting to $2 million reported as part of other current assets in the balance sheet and $2 million regulatory liabilities reported on the balance sheet as part of accounts payable and accrued liabilities both representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers continually. Long-term regulatory liabilities that the Partnership has collected in its current rates related to future removal costs on its transmissions and gathering facilities are included in other long-term liabilities (refer to Note 10).

NOTE 3 ACCOUNTING PRONOUNCEMENTS

Changes in Accounting Policies effective January 1, 2019

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee 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 twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statements of income. The new guidance does not make extensive changes to lessor accounting.

Under the new guidance, the Partnership determines if an arrangement is a lease at inception. Operating leases are recognized as ROU assets and included in Property, plant and equipment while corresponding liabilities are included in "Accounts payable and other" and "Other long-term liabilities" on the consolidated balance sheet. Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at commencement date. As the Partnership's leases do not provide an implicit rate, the Partnership uses an incremental borrowing rate that approximates its borrowing cost based on the information available at commencement date in determining the present value of future payments. The operating lease ROU asset also includes any lease payments made and initial direct costs incurred and excludes lease incentives. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Partnership will exercise that option. Operating lease expense is recognized on a straight-line basis over the lease term and included in "Operation and maintenance expenses" in the consolidated statements of income.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption and recognize a cumulative-effect adjustment to the opening balance of equity in the period of adoption. This transition option allowed us to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

We elected available practical expedients and exemptions upon adoption which allowed us:

- not to reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard;
- to carry forward the historical lease classification and our accounting treatment for land easements on existing agreements;
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption;
- to not separate lease and non-lease components for all leases for which we are the lessee; and
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

In the application of the new guidance, assumptions and judgments are used to determine the following:

- whether a contract contains a lease and the duration of the lease term including exercising lease renewal options. The lease term for all of the Partnership's leases includes the non-cancellable period of the lease plus any additional periods covered by either the Partnership's option to extend (or not to terminate) the lease that the Partnership is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor; and
- the discount rate for the lease.

The standard did not impact our previously reported results and did not have a material impact on the Partnership's consolidated balance sheets, consolidated statements of income or consolidated statement of cash flows at the date of adoption.

The primary change as a result of the adoption was the recognition of ROU assets and lease liabilities for operating leases which was approximately $0.6 million at January 1, 2019 and $0.4 million at December 31, 2019. For the year ended December 31, 2019, the Partnership's operating lease cost was not material to the Partnership's consolidated results. At December 31, 2019, the weighted average remaining term and discount rate of the Partnership's operating leases were approximately 1.96 years and 3.57 percent, respectively.

Fair Value Measurement

In August 2018, the FASB issued new guidance that amends 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 of certain or all requirements is permitted. The Partnership elected to adopt this guidance effective first quarter

2019. The guidance was applied retrospectively and did not have a material effect on the Partnership's consolidated financial statements.

Future accounting changes

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that 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 (loss). 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 was effective January 1, 2020 and will be applied using a modified retrospective approach. The adoption of this new guidance will not have a material impact on the Partnership's consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance was effective January 1, 2020, and has been applied on a retrospective basis. The adoption of this new guidance has not had a material impact on the Partnership's consolidated financial statements.

NOTE 4 GOODWILL AND REGULATORY

During late 2018, the Partnership completed its regulatory filings to address the issues contemplated by the 2017 Tax Act and certain FERC actions that began in March of 2018, namely FERC's Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that 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 quantified the rate impact of the 2017 Tax Act on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by Master Limited Partnerships (MLPs):

Pipelines filing FERC Form No. 501-G had 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 guaranteed a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G showed 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 believed that using the limited Section 4 option would not result in just and reasonable rates. If the pipeline committed to file by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it did not believe the pipeline's rates must change; or
- Option 4: take no action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that had not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

Filings required by the Final Rule

Prior to the 2018 FERC Actions, the Partnership's pipeline systems did not have a requirement to file or adjust their rates earlier than 2022 as a result of their existing rate settlements. However, several of our pipeline systems accelerated such adjustments as a result of the 2018 FERC Actions as summarized in the table below.

	Form 501-G Filing Option	Impact on Maximum Rates	Moratorium, Mandatory Filing Requirements and Other Considerations
Great Lakes	Option 1; reflected an elimination of income tax allowance and ADIT; Limited Section 4 accepted by FERC; 501-G Docket remains open	2.0% rate reduction effective February 1, 2019	No moratorium in effect; comeback provision with new rates to be effective by October 1, 2022
GTN	Settlement approved by FERC on November 30, 2018 eliminated the requirement to file Form 501-G	A refund of $10 million to its firm customers in 2018; 10.0% rate reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021; these reductions will replace the 8.3% rate reduction in 2020 agreed to as part of the last settlement in 2015	Moratorium on rate changes until December 31, 2021; comeback provision with new rates to be effective by January 1, 2022; Settlement agreement reflected an elimination of income tax allowance and ADIT
Northern Border	Option 1; reflected an elimination of income tax allowance and ADIT; subsequent settlement approved by FERC on May 24, 2019; 501-G docket closed	2.0% rate reduction effective February 1, 2019 to December 31, 2019 extended until July 1, 2024 unless superseded by a subsequent rate case or settlement	No moratorium in effect; comeback provision with new rates to be effective by July 1, 2024
Bison	Option 3; reflected an elimination of income tax allowance and ADIT; accepted by FERC; 501-G docket closed	No rate changes proposed	No moratorium or comeback provisions
Iroquois	Option 3; reflected an elimination of income tax allowance and ADIT; subsequent settlement approved by FERC on May 2, 2019; 501-G docket closed	3.25% rate reduction effective March 1, 2019; additional 3.25% rate reduction effective April 1, 2020	Moratorium on rate changes until September 1, 2020; comeback provision with new rates to be effective by March 1, 2023
PNGTS	Option 3; reflected an elimination of income tax allowance and ADIT; accepted by FERC; 501-G docket closed	No rate changes	No moratorium or comeback provisions
North Baja	Option 1; reflected an elimination of income tax allowance and ADIT; accepted by FERC; 501-G docket closed	10.8% rate reduction effective December 1, 2018	No moratorium or comeback provisions; approximately 90 percent of North Baja's contracts are negotiated; 10.8% reduction is on maximum rate contracts only
Tuscarora	Option 1; reflected an elimination of income tax allowance and ADIT; subsequent settlement approved by FERC on May 2, 2019; 501-G docket closed	1.7% rate reduction effective February 1, 2019; additional rate reduction of 10.8% effective August 1, 2019	Moratorium on rate changes until January 31, 2023; comeback provision with new rates to be effective by February 1, 2023; Settlement agreement reflected an elimination of income tax allowance and ADIT

Rate settlements

As noted in the above table, new rate settlements were entered into by GTN, Tuscarora, Iroquois and Northern Border to address the issues that came out of the 2018 FERC Actions. Additional details of the settlements are outlined below:

GTN

On November 30, 2018, FERC approved the rate settlement filed by GTN to address the changes proposed by the 2018 FERC Actions within its rates via an amendment to its prior settlement in 2015 (the 2018 GTN Settlement). In addition to the rate step downs described in the above table, the 2018 GTN Settlement will also reflect an elimination of tax allowance previously recovered in rates along with ADIT for rate-making purposes.

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 (the 2018 GTN Rate Refund). As a result of this, the Partnership established a $10 million provision for this revenue sharing as an offset against revenue in the income statement. The corresponding refund liability was paid by GTN before December 31, 2018.

Tuscarora

On December 6, 2018, Tuscarora elected to make a limited NGA Section 4 filing to reduce its maximum rates by approximately 1.7 percent and eliminate its deferred income tax balances previously used for rate setting (Option 1). On March 15, 2019, Tuscarora filed an uncontested settlement with FERC to address the issues contemplated by the 2017 Tax Act and 2018 FERC Actions via an amendment to its prior 2016 settlement (the 2019 Tuscarora Settlement). Among the terms of the 2019 Tuscarora Settlement, Tuscarora agreed to reduce its existing maximum system rates by 1.7 percent effective February 1, 2019 through to July 31, 2019 followed by an additional decrease of 10.8 percent for the period August 1, 2019 through the term of the settlement. Tuscarora is required to have new rates in effect on February 1, 2023. Tuscarora and its customers also agreed on a moratorium on rate changes until January 31, 2023. The 2019 Tuscarora Settlement, which was approved by FERC on May 2, 2019, will also reflect an elimination of the tax allowance previously recovered in rates along with ADIT for rate-making purposes.

Iroquois

On December 6, 2018, Iroquois submitted its FERC Form No. 501-G in response to the FERC Final Rule along with an explanation as to why rate changes were not required. On February 28, 2019, Iroquois filed an uncontested settlement with FERC to address the issues contemplated by the 2017 Tax Act and 2018 FERC Actions via an amendment to its prior 2016 settlement (the 2019 Iroquois Settlement). Among the terms of the 2019 Iroquois Settlement, Iroquois agreed to reduce its existing maximum system rates by 6.5 percent to be implemented in two phases, (i) effective March 1, 2019, a 3.25 percent rate reduction and (ii) effective April 1, 2020, an additional 3.25 percent rate reduction, which will conclude the total 6.5 percent rate reduction from the 2016 settlement rates. The 2019 Iroquois Settlement, which was approved by FERC on May 2, 2019, preserved the 2016 settlement moratorium on further rate changes until September 1, 2020. Unless superseded by a subsequent rate case or settlement, Iroquois will be required to have new rates in effect by March 1, 2023.

Northern Border

On May 24, 2019, Northern Border's amended settlement agreement filed with the FERC for approval on April 4, 2019, was approved and its 501-G proceeding was terminated. Until superseded by a subsequent rate case or settlement, effective January 1, 2020, the amended settlement agreement extends the two percent rate reduction implemented on February 1, 2019 to July 1, 2024.

2018 Tuscarora Goodwill Impairment

As noted above, in the fourth quarter of 2018, Tuscarora initiated its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction of its maximum rates. In connection with our annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, which included estimates related to discount rates and earnings multiples. In doing so, we incorporated the expected impact of Tuscarora's regulatory approach in response to the 2018 FERC Actions, in which it elected to make a limited NGA Section 4 filing to reduce its maximum rates and eliminate its deferred income tax balances previously used for rate setting. Additionally, for the year ended December 31, 2018, we have considered the outcome of the 2019 Tuscarora Settlement with its customers in our overall conclusion.

Our analysis resulted in the estimated fair value of Tuscarora not exceeding its carrying value, including goodwill. The fair value was measured using a discounted cash flow approach whereby the expected cashflows were discounted using a risk adjusted discount rate to determine fair value.

As a result, we recorded a goodwill impairment charge amounting to $59 million against Tuscarora's goodwill balance of $82 million. The impairment charge was recorded in the Impairment of goodwill line on the Consolidated statement of operations and reduced our total consolidated goodwill balance from $130 million to $71 million.

2019 Analysis

In 2019, based on our qualitative analysis of Tuscarora and North Baja's current market conditions, which includes consideration of the potential qualitative impact of current year changes in the multiples and discount rate assumptions compared to multiples and discount rate assumptions used in the prior quantitative model, we believe there is a greater than 50 percent likelihood that Tuscarora and North Baja's estimated fair value exceeded their carrying value. As a result, at December 31, 2019, we have not identified an impairment on the $71 million of goodwill related to Tuscarora ($23 million) and North Baja ($48 million) acquisitions.

There is a risk that adverse changes in our key assumptions could result in an additional future impairment on Tuscarora's remaining goodwill of $23 million.

NOTE 5 EQUITY INVESTMENTS

The Partnership has equity interests in Northern Border, Great Lakes and, effective June 1, 2017, 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 TC Energy. 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 investees.

(millions of dollars)	Ownership Interest at December 31, 2019	Equity Earnings[b] Year ended December 31 2019	2018	2017	Equity Investments December 31 2019	2018
Northern Border[a]	50.00%	**69**	68	67	**422**	497
Great Lakes	46.45%	**51**	59	31	**491**	489
Iroquois	49.34%	**40**	46	26	**185**	210
		160	173	124	**1,098**	1,196

(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 in April 2006. The fee was fully amortized in May 2018.

(b) Equity Earnings represents our share in investee's earnings and does not include any impairment charge on the equity method investment recorded as a reduction of carrying value of these investments. Accordingly, no impairment charge was recorded by the Partnership on its equity investees for all the periods presented here.

Distributions from Equity Investments

Distributions received from equity investments for the year ended December 31, 2019 were $258 million (2018 — $198 million; 2017 — $145 million) of which $58 million (2018 — $10 million and 2017 — $5 million) was considered a return of capital and is included in Investing activities in the Partnership's consolidated statement of cash flows. The return of capital was related to our investment in Northern Border and Iroquois (see further discussion below).

Northern Border

During the year ended December 31, 2019, the Partnership received distributions from Northern Border amounting to $144 million (2018 — $83 million; 2017 — $83 million) The $144 million includes the Partnership's 50 percent share of the Northern Border $100 million distribution in June 2019. The $100 million distribution was 100 percent financed by borrowing on Northern Border's $200 million revolving credit facility. The $50 million of cash the Partnership received did not represent a distribution of operating cash flow during the period and, therefore, it was reported as a return of investment in the Partnership's consolidated statement of cash flows.

On September 1, 2017, the Partnership made an equity contribution to Northern Border amounting to $83 million. This amount represents the Partnership's 50 percent share of a $166 million capital contribution request from Northern Border to reduce the outstanding balance of its revolving credit facility to increase its available borrowing capacity.

The Partnership recorded no undistributed earnings from Northern Border for the years ended December 31, 2019, 2018 and 2017. At December 31, 2019 the Partnership had a $115 million (December 31, 2018 — $115 million) difference between the carrying value of Northern Border and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in the Partnership's investment in Northern Border relating to the Partnership's April 2006 acquisition of an additional 20 percent general partnership interest in Northern Border.

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

December 31 (millions of dollars)	**2019**	**2018**
Assets		
Cash and cash equivalents	**21**	10
Other current assets	**37**	36
Property, plant and equipment, net	**989**	1,037
Other assets	**12**	13
	1,059	1,096
Liabilities and Partners' Equity		
Current liabilities	**42**	34
Deferred credits and other	**39**	35
Long-term debt, net[(a)]	**364**	264
Partners' equity		
Partners' capital	**615**	764
Accumulated other comprehensive loss	**(1)**	(1)
	1,059	1,096

Year ended December 31 (millions of dollars)	**2019**	**2018**	**2017**
Transmission revenues	**300**	289	291
Operating expenses	**(82)**	(78)	(78)
Depreciation	**(62)**	(60)	(59)
Financial charges and other	**(18)**	(15)	(18)
Net income	**138**	136	136

(a) No current maturities as of December 31, 2019 or 2018.

Great Lakes

During the year ended December 31, 2019, the Partnership received distributions from Great Lakes amounting to $59 million (2018 — $58 million; 2017 — $35 million), all of which were reported as a return on investment in the Partnership's consolidated statement of cash flows.

The Partnership made equity contributions to Great Lakes of $5.1 million and $4.6 million in the first and fourth quarter of 2019, respectively. These amounts represent the Partnership's 46.45 percent share of an $11 million and $10 million cash call from Great Lakes to make scheduled debt repayments.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2019, 2018, and 2017.

At December 31, 2019, the equity method goodwill related to Great Lakes amounted to $260 million (December 31, 2018 — $260 million). The equity method goodwill relates to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes and is the difference between the carrying value of our investment in Great Lakes and the underlying equity in Great Lakes' net assets.

During the fourth quarter of 2018, Great Lakes finalized its regulatory approach in response to the 2018 FERC Actions and elected to make a limited NGA section 4 filing with FERC to reduce its maximum rates and eliminate its tax allowance and deferred income tax balances previously used for rate setting. As a result of this action, and because the estimated fair value of our investment in Great Lakes exceeded its carrying value by less than 10 percent in its 2017 valuation, we performed a quantitative test to determine if there was other than temporary decline in Great Lakes' fair value.

The assumptions we used in our analysis related to the estimated fair value of our equity investment in Great Lakes included expected results from its limited NGA Section 4 filing with FERC, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment, which includes estimates related to discount rates and earnings multiples. At December 31, 2018, we concluded the estimated fair value of our investment in Great Lakes exceeded its carrying value by more than 10 percent.

In 2019, Great Lakes current market conditions and other factors relevant to Great Lakes' long-term financial performance have remained relatively stable during the year. There is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in an additional future impairment of the carrying value of our investment in Great Lakes.

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

December 31 (millions of dollars)	**2019**	**2018**
Assets		
Current assets	**72**	75
Property, plant and equipment, net	**685**	689
	757	764
Liabilities and Partners' Equity		
Current liabilities	**33**	26
Long-term debt, net[(a)]	**219**	240
Other long-term liabilities	**6**	4
Partners' equity	**499**	494
	757	764

Year ended December 31 (millions of dollars)	**2019**	**2018**	**2017**
Transmission revenues	**238**	246	181
Operating expenses	**(79)**	(68)	(66)
Depreciation	**(32)**	(32)	(29)
Financial charges and other	**(16)**	(18)	(20)
Net income	**111**	128	66

(a) Includes current maturities of $21 million as of December 31, 2019 and December 31, 2018.

Iroquois

For the year ended December 31, 2019, the Partnership received distributions from Iroquois amounting to $55 million (2018 — $56 million) which includes the Partnership's 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $8 million (2018 — $10 million) (Refer to Note 8). This amount is reported as distributions received as return of investment in the Partnership's consolidated statement of cash flows.

The Partnership made an equity contribution to Iroquois of $4 million in August 2019. This amount represents the Partnership's 49.34 percent share of an $7 million cash call from Iroquois to cover costs of regulatory approvals related to their capital project.

The Partnership recorded no undistributed earnings for the years ended December 31, 2019 and 2018 and for the period from June 1, 2017, acquisition date, through December 31, 2017. At December 31, 2019 and 2018, the Partnership had a $40 million and $41 million difference, respectively, between the carrying value of Iroquois and the underlying equity in the net assets primarily from TC Energy's carrying value and is due to their fair value assessment of Iroquois' assets at the time of its acquisition of interests from third parties (refer to Note 2 — Acquisitions and Goodwill for our accounting policy on acquisitions from TC Energy).

Distribution receivable from Iroquois

Iroquois declared its third quarter 2019 distribution of $28 million on November 1, 2019, and the Partnership received its 49.34 percent share or $14 million on January 6, 2020.

The summarized financial information provided to us by Iroquois for the period from the June 1, 2017 acquisition date through December 31, 2019 is as follows:

December 31 (millions of dollars)	**2019**	**2018**
ASSETS		
Cash and cash equivalents	**43**	80
Other current assets	**36**	32
Property, plant and equipment, net	**570**	581
Other assets	**16**	8
	665	701
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	**34**	19
Net long-term debt, net[(a)]	**317**	325
Other non-current liabilities	**20**	14
Partners' equity	**294**	343
	665	701

(millions of dollars)	**Year ended December 31, 2019**	**Year ended December 31, 2018**	**Period of 7 months ended December 31, 2017**
Transmission revenues	**180**	194	110
Operating expenses	**(58)**	(57)	(32)
Depreciation	**(29)**	(29)	(17)
Financial charges and other	**(11)**	(14)	(9)
Net income	**82**	94	52

(a) Includes current maturities of $3 million as of December 31, 2019 (December 31, 2018 — $146 million).

NOTE 6 REVENUES

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for 2019 and 2018 reflect the application of the new guidance, while the reported results for 2017 were prepared under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP".

Disaggregation of Revenues

For the year ended December 31, 2019 and 2018, effectively all of the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2 — Significant Accounting Policies.

During the fourth quarter of 2018, Bison received an unsolicited offer from Tenaska Marketing Ventures (Tenaska) regarding the termination of its contract. Also, during 2018, through a Permanent Capacity Release Agreement, Tenaska assumed Anadarko Energy Services Company's (Anadarko) ship-or-pay contract obligation on Bison, which was the largest contract on Bison. Bison and Tenaska mutually agreed to terms which included a non-refundable payment to Bison of $95.4 million in December 2018 in exchange for the termination of all its contract obligations with Bison. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison in exchange for a non-refundable payment to Bison of approximately $2.0 million in December 2018. At the termination of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018. Accordingly, the $97 million we received from contract terminations was considered as revenue from capacity and transportation contracts with customers and therefore no further disaggregation of revenue is needed (See also related discussion under Note 7 — Plant Property and Equipment).

As noted under Note 2 — Significant Accounting Policies, a portion of our revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. We use our best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue we recognized. Accordingly, as part of the 2018 GTN Settlement, we have issued the 2018 GTN Rate Refund and recognized a $10 million offset against revenue in the income statement for the year ended December 31, 2018 (See also Note 4 for more information).

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 December 31, 2019 and 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

All of the Partnership's contract balances pertain to receivables from contracts with customers amounting to $37 million at December 31, 2019 (December 31, 2018 — $44 million) and are recorded as Trade accounts receivable and reported as "Accounts receivable and other" in the Partnership's consolidated balance sheet (Refer to Note 21).

Additionally, our accounts receivable represent the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

Right to invoice practical expedient

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 capacity contracted and 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.

NOTE 7 PROPERTY, PLANT AND EQUIPMENT

The following table includes property, plant and equipment of our consolidated entities:

December 31 (millions of dollars)	2019			2018		
	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**1,907**	**(929)**	**978**	1,901	(876)	1,025
Compression	**584**	**(202)**	**382**	550	(182)	368
Metering and other	**180**	**(56)**	**124**	176	(52)	124
Construction in progress	**44**	**—**	**44**	12	—	12
	2,715	**1,187**	**1,528**	2,639	(1,110)	1,529

2018 Impairment of Bison's long-lived assets

At December 31, 2018, the Partnership performed an impairment analysis on Bison's long-lived assets in connection with the termination of certain customer transportation agreements (refer to Note 6 — Revenues).

With the loss of future cash flows resulting from the contract terminations described above and the persistence of unfavorable market conditions which inhibited systems flows on the pipeline during the fourth quarter of 2018, the Partnership recognized an impairment charge of $537 million relating to the remaining carrying value of Bison's property, plant and equipment after determining that it was no longer recoverable. The impairment charge was recorded under Impairment of long-lived assets line on the Consolidated statement of operations.

The Partnership continues to explore alternative transportation-related options for Bison; however, management is currently unable to quantify the future cash flows of a viable, operating plan beyond the remaining customer contracts' expiry in January 2021. The Partnership will continue to maintain Bison to stand ready for redevelopment and has concluded that the remaining obligations of Bison, primarily in the form of ad valorem tax obligations and operating and maintenance costs, exceed the net cash inflows that management currently considers probable and estimable.

NOTE 8 ACQUISITIONS

2017 Acquisition

On June 1, 2017, the Partnership acquired from subsidiaries of TC Energy a 49.34 percent interest in Iroquois, together with an additional 11.81 percent interest in PNGTS resulting in the Partnership owning a 61.71 percent interest in PNGTS (the 2017 Acquisition). The total purchase price of the 2017 Acquisition was $765 million plus final purchase price adjustments amounting to $50 million. The purchase price consisted of (i) $710 million for the Iroquois interest (less $164 million, which reflected our 49.34 percent share of Iroquois outstanding debt on June 1, 2017), (ii) $55 million for the additional 11.81 percent interest in PNGTS (less $5 million, which reflected our 11.81 percent proportionate share in PNGTS' outstanding debt on June 1, 2017) (iii) final working capital adjustments for Iroquois and PNGTS amounting to $19 million and $3 million, respectively and (iv) additional consideration of $28 million for the surplus cash on Iroquois' balance sheet. Additionally, the Partnership paid $1,000 for the option to acquire TC Energy's remaining 0.66 percent interest in Iroquois, which expired on January 3, 2019. The Partnership funded the cash portion of the 2017 Acquisition through a combination of proceeds from the May 2017 public debt offering (refer to Note 9) and borrowing under our senior facility under revolving credit agreement as amended and restated, dated September 29, 2017 (Senior Credit Facility).

At the date of the 2017 Acquisition, there was significant cash on Iroquois' balance sheet. Pursuant to the Purchase and Sale Agreement associated with the acquisition of the Iroquois interest, as amended, the Partnership agreed to pay $28 million plus interest to TC Energy on August 1, 2017 for its 49.34 percent share of the cash determined to be surplus to Iroquois' operating needs.

Iroquois' partners adopted a distribution resolution to address the surplus cash on its balance sheet post-closing of this acquisition transaction. The Partnership is expected to receive the $28.4 million of unrestricted cash as part of its quarterly distributions from Iroquois over 11 quarters under the terms of the resolution, which began with Iroquois' second quarter 2017 distribution on August 1, 2017. As of February 20, 2020, the Partnership has received $25.8 million, and the remaining balance is expected to be received by March 31, 2020.

The acquisition of a 49.34 percent interest in Iroquois was accounted for as a transaction between entities under common control, whereby the equity investment in Iroquois was recorded at TC Energy's carrying value and the total excess purchase price paid was recorded as a reduction in Partners' Equity.

Iroquois' net purchase price was allocated as follows:

(millions of dollars)	
Net Purchase Price[(a)]	593
Less: TC Energy's carrying value of Iroquois at June 1, 2017	223
Excess purchase price[(b)]	370

(a) Total purchase price of $710 million plus final working capital adjustment of $19 million and the additional consideration on Iroquois surplus cash amounting to approximately $28 million less the assumption of $164 million of proportional Iroquois debt by the Partnership.

(b) The excess purchase price of $370 million was recorded as a reduction in Partners' Equity.

The acquisition of an additional 11.81 percent interest in PNGTS, which resulted in the Partnership owning 61.71 percent in PNGTS, was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby assets and liabilities of PNGTS were recorded at TC Energy's carrying value and the Partnership's 2016 historical financial information, except net income per common unit, was recast to consolidate PNGTS for all periods presented.

The PNGTS purchase price was recorded as follows:

(millions of dollars)	
Current assets	25
Property, plant and equipment, net	294
Current liabilities	(4)
Deferred state income taxes	(10)
Long-term debt, including current portion	(41)
	264
Non-controlling interest	(100)
Carrying value of pre-existing Investment in PNGTS	(132)
TC Energy's carrying value of the acquired 11.81 percent interest at June 1, 2017	32
Excess purchase price over net assets acquired[(a)]	21
Total cash consideration[(b)]	53

(a) The excess purchase price of $21 million was recorded as a reduction in Partners' Equity.

(b) Total purchase price of $55 million plus the final working capital adjustment of $3 million less the assumption of $5 million of proportional PNGTS debt by the Partnership.

NOTE 9 DEBT AND CREDIT FACILITIES

(millions of dollars)	2019	Weighted Average Interest Rate for the Year Ended December 31, 2019	2018	Weighted Average Interest Rate for the Year Ended December 31, 2018
TC PipeLines, LP				
Senior Credit Facility due 2021	—	—	40	3.14%
2013 Term Loan Facility due 2022	**450**	**3.52%**	500	3.23%
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	2.93%
PNGTS				
Revolving Credit Facility due 2023	**39**	**3.47%**	19	3.55%
Tuscarora				
Unsecured Term Loan due 2020	**23**	**3.39%**	24	3.10%
North Baja				
Unsecured Term Loan due 2021	**50**	**3.34%**	50	3.54%
	2,012		2,118	
Less:unamortized debt issuance costs and debt discount	**9**		10	
Less: current portion	**123**[(b)]		36	
	1,880		2,072	

(a) Fixed interest rate.

(b) Includes GTN's 5.29% Unsecured Senior Notes due June 1, 2020 and Tuscarora's Unsecured Term Loan due August 21, 2020.

TC PipeLines, LP

The Partnership's Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, under which no borrowings were outstanding at December 31, 2019 (December 31, 2018 — $40 million), leaving $500 million available for future borrowing.

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be the lenders' base rate or the London Interbank Offered Rate (LIBOR) plus, in either case, an applicable margin that is based on the Partnership's long-term unsecured credit ratings. The Senior Credit Facility permits the Partnership to specify the portion of the borrowings to be covered by specific interest rate options and, for LIBOR-based borrowings, to specify the interest rate period. The Partnership is required to pay a commitment fee based on its credit rating and on the unused principal amount of the commitments under the Senior Credit Facility. The Senior Credit Facility has a feature whereby at any time, so long as no event of default has occurred and is continuing, the Partnership may request an increase in the Senior Credit Facility of up to $500 million, but no lender has an obligation to increase their respective share of the facility.

The LIBOR-based interest rate on the Senior Credit Facility was 3.77 percent at December 31, 2018.

On September 29, 2017, the Partnership's term loan credit facility under a term loan agreement as amended on September 29, 2017 (2013 Term Loan Facility) was amended to extend the maturity period through October 2, 2022. The 2013 Term Loan Facility bears interest based, at the Partnership's election, on the LIBOR or the base rate plus, in either case, an applicable margin. The base rate equals the highest of (i) SunTrust Bank's prime rate, (ii) 0.50 percent above the

U.S. federal funds rate and (iii) 1.00 percent above one-month LIBOR. The applicable margin for the term loan is based on the Partnership's senior debt rating and ranges between 1.125 percent and 2.00 percent for LIBOR borrowings and 0.125 percent and 1.00 percent for base rate borrowings.

On June 26, 2019, the Partnership repaid $50 million of the principal balance under its 2013 Term Loan Facility using proceeds from Northern Border's additional distribution (see Note 5). Additionally, in conjunction with this repayment, the Partnership also terminated an equivalent amount in interest rate swaps that were used to hedge this facility at a rate of 2.81 percent. As of December 31, 2019, 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 (2018 — 3.26 percent). Prior to hedging activities, the LIBOR-based interest rate was 2.94 percent at December 31, 2019 (December 31, 2018 — 3.60 percent).

The Senior Credit Facility and the 2013 Term Loan Facility require the Partnership to maintain a debt to adjusted cash flow leverage ratio of 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 3.41 to 1.00 as of December 31, 2019.

The Senior Credit Facility and the 2013 Term Loan Facility contain additional covenants that include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurrence of additional debt by the Partnership's subsidiaries and distributions to unitholders. Upon any breach of these covenants, amounts outstanding under the Senior Credit Facility and the 2013 Term Loan Facility may become immediately due and payable.

On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 Acquisition (Refer to Note 8). The indenture for the notes contains customary investment grade covenants.

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. 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 0.70 to 1.00 as of December 31, 2019. The facility is being utilized by PNGTS primarily to fund the costs of its expansion projects and for general partnership purposes. As of December 31, 2019, $39 million was drawn on the Revolving Credit Facility and the LIBOR-based interest rate was 2.99 percent (December 31, 2018 — 3.60 percent).

GTN

GTN's Unsecured Senior Notes 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 December 31, 2019 was 39.1 percent.

During the second quarter of 2019, GTN's Unsecured Term Loan Facility matured and was fully repaid using the Partnership's funds from operations. The LIBOR-based interest rate applicable to GTN's Unsecured Term Loan Facility was 3.30 percent at December 31, 2018.

GTN's $100 million 5.29% Unsecured Senior Notes due June 1, 2020 are expected to be refinanced in full or at an amount based on the Partnership's preferred capitalization levels.

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 December 31, 2019, the ratio was 8.72 to 1.00.

The LIBOR-based interest rate applicable to Tuscarora's Unsecured Term Loan Facility was 2.82 percent at December 31, 2019 (December 31, 2018 — 3.47 percent).

Tuscarora's $23 million variable rate Unsecured Term Loan due August 21, 2020 is expected to be refinanced in full or at an amount based on the Partnership's preferred capitalization levels.

North Baja

On December 19, 2018, North Baja entered into a $50 million unsecured variable rate term loan facility, which matures on December 19, 2021. The net proceeds were used for general partnership purposes. The variable interest rate is based on LIBOR plus an applicable margin. The LIBOR-based interest rate on this term loan facility was 2.77 percent at December 31, 2019 (December 31, 2018 — 3.54 percent). North Baja's Term Loan Facility contains a covenant that limits total debt to no greater than 70 percent of North Baja's total capitalization. North Baja's total debt to total capitalization ratio at December 31, 2019 is 39.8 percent.

Partnership (TC PipeLines, LP and its subsidiaries)

At December 31, 2019, 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 Partnership Agreement, incurring additional debt and distributions to unitholders.

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

(millions of dollars)	
2020	123
2021	400
2022	450
2023	39
2024	—
Thereafter	1,000
	2,012

NOTE 10 OTHER LIABILITIES

December 31 (millions of dollars)	**2019**	**2018**
Regulatory liabilities	**29**	27
Other liabilities	**7**	2
	36	29

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as "negative salvage") and recognizes regulatory liabilities in this respect on the balance sheet. Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by FASB ASC 410, *Accounting for Asset Retirement Obligations*.

NOTE 11 PARTNERS' EQUITY

At December 31, 2019, the Partnership had 71,306,396 common units outstanding, of which 54,221,565 were held by non-affiliates and 17,084,831 common units were held by subsidiaries of TC Energy, including 5,797,106 common units held by our General Partner. Additionally, TC Energy, through our General Partner, owns 100 percent of our IDRs and a two percent general partner interest in the Partnership. TC Energy also holds 100 percent of our 1,900,000 outstanding Class B units.

At-the-Market Equity Issuance Program (ATM Program)

In August 2014, we established an ATM Program that allowed the Partnership from time to time to offer and sell, through sales agents, common units representing limited partner interests. The ATM Program was initially established with an aggregate gross sales limit of $200 million.

In August 2016 we replenished the capacity available under the existing ATM Program to allow for the offer and sale of common units having an aggregate gross sales limit of up to $400 million.

In 2017, the Partnership issued 3.2 million common units under the ATM Program generating net proceeds of approximately $173 million, plus an additional $3 million from the General Partner to maintain its two percent interest. The commissions to our sales agents were approximately $2 million. The net proceeds were used to repay a portion of the borrowings under the Senior Credit Facility and for general partnership purposes.

In 2018, the Partnership issued 0.7 million common units under the ATM Program generating net proceeds of approximately $39 million, plus an additional $1 million from the General Partner to maintain its two percent interest. The commissions to our sales agents were nil. The net proceeds were used to repay a portion of the borrowings under the Senior Credit Facility and for general partnership purposes.

In August 2019, the ATM Program expired with no common unit issuances in 2019.

Common unit issuance subject to rescission

In connection with a late filing of an employee-related Form 8-K with the SEC in March 2016, the Partnership became ineligible to use the then effective shelf registration statement upon filing of its Annual Report on Form 10-K for the year ended December 31, 2015. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the Partnership's ATM program may have had a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to the Partnership. The Securities Act of 1933, as amended (Securities Act) generally requires that any claim brought for a violation of Section 5 of the Securities Act be brought within one year of violation.

No unitholder claimed or attempted to exercise any rescission rights prior to their expiry dates and the final rights related to the sales of such units expired on May 19, 2017. As a result of the expiration, the amount associated with these rights was reclassified back to partners' equity. At December 31, 2019 and 2018, there were no outstanding common units subject to rescission on the Partnership's consolidated balance sheet.

Issuance of Class B units

The Class B Units issued on April 1, 2015 to finance a portion of the Partnership's acquisition of the remaining 30 percent interest of GTN from TC Energy represent a limited partner interest in us and entitle TC Energy 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. The Class B units contain no mandatory or optional redemption features and are also non-convertible, non-exchangeable, non-voting and rank equally with common units upon liquidation.

Additionally, the Class B Distribution was reduced by 35 percent, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018. The Class B Reduction was implemented during the first quarter of 2018 following the Partnership's common unit distribution reduction of 35 percent from its fourth quarter 2017 distribution level of $1.00 per common unit. 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.

The Class B units' equity account is increased by the "Class B Distribution," less the "Class B Reduction," if any until such amount is declared for distribution and paid every first quarter of the subsequent year. For the years ended December 31, 2019, 2018 and 2017, the Class B units' equity account was increased by $8 million, $13 million and $15 million, respectively. (Refer to Notes 14 and 15).

NOTE 12 ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The changes in accumulated other comprehensive income (loss) (AOCI) by component are as follows:

(millions of dollars)	Cash flow hedges	Equity Investments	Total
Balance at December 31, 2016[a]	**(2)**	—	(2)
Change in fair value of cash flow hedges	**5**	—	5
Amounts reclassified from AOCI	**—**	—	—
PNGTS' amortization of realized loss on derivative instrument *(Note 20)*	**1**	—	1
Other comprehensive income — effects of Iroquois' retirement benefit plans	**—**	1	1
Net other comprehensive income	**6**	1	7
Balance at December 31, 2017	**4**	1	5
Change in fair value of cash flow hedges	**(2)**	—	(2)
Amounts reclassified from AOCI	**5**	—	5
PNGTS' amortization of realized loss on derivative instrument *(Note 20)*	**1**	—	1
Other comprehensive loss — effects of Iroquois' retirement benefit plans	**—**	(1)	(1)
Net other comprehensive income (loss)	**4**	(1)	3
Balance as of December 31, 2018	**8**	—	8
Change in fair value of cash flow hedges	**(13)**	—	(13)
Amounts reclassified from AOCI	**(1)**	—	(1)
Other comprehensive income — effects of Iroquois' retirement benefit plans	**—**	1	1
Net other comprehensive income (loss)	**(14)**	1	(13)
Balance as of December 31, 2019	**(6)**	1	(5)

(a) Recast to consolidate PNGTS (Refer to in Notes 2 and 8). Additionally, AOCI as presented here is net of non-controlling interest on PNGTS.

NOTE 13 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	2019	2018	2017
Interest expense[a]	**88**	95	83
Net realized gain related to the interest rate swaps	**(1)**	(2)	—
PNGTS' amortization of realized loss on derivative instrument *(Note 20)*	**—**	1	1
Other	**(4)**	(2)	(2)
	83	92	82

(a) Interest expense includes amortization of debt issuance costs and discount costs.

NOTE 14 NET INCOME (LOSS) PER COMMON UNIT

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

The amounts allocable to the General Partner equals an amount based upon the General Partner's 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 (Refer to Note 15).

The amount allocable to the Class B units is based upon 30 percent of GTN's distributable cash flow after certain annual thresholds and adjustments (Refer to Note 11).

Net income (loss) per common unit was determined as follows:

(millions of dollars, except per common unit amounts)	2019	2018	2017
Net income (loss) attributable to controlling interests	**280**	(182)	252
Net income attributable to PNGTS' former parent[(a)]	**—**	—	(2)
Net income (loss) allocable to General Partner and Limited Partners	**280**	(182)	250
Incentive distributions attributable to the General Partner[(b)]	**—**	—	(12)
Net income attributable to the Class B units[(c)]	**(8)**	(13)	(15)
Net income (loss) allocable to the General Partner and common units	**272**	(195)	223
Net (income) loss allocable to the General Partner's two percent interest	**(5)**	4	(4)
Net income (loss) attributable to common units	**267**	(191)	219
Weighted average common units outstanding *(millions)* — basic and diluted	**71.3**	71.3	69.2
Net income (loss) per common unit — basic and diluted	**$3.74**	$(2.68)	$3.16

(a) Net income allocable to General and Limited Partners excludes net income attributed to PNGTS' former parent as it was allocated to TC Energy 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 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) As discussed in Note 11, the Class B units entitle TC Energy to a distribution which is an amount based on 30 percent of GTN's distributions after exceeding certain annual thresholds and Class B Reduction. The distribution will be payable in the first quarter with respect to the prior year's distributions. Consistent with the application of Accounting Standards Codification (ASC) Topic 260 — "Earnings per share," the Partnership allocated the Class B units distribution in an amount equal to 30 percent of GTN's total distributable cash flows during the year ended December 31, 2019 less the threshold level of $20 million (2018 and 2017 — less $20 million) and less the Class B Reduction (2019 — $4 million, 2018 — $7 million. The Class B Reduction did not apply during 2017).

NOTE 15 CASH DISTRIBUTIONS

The Partnership makes cash distributions to its partners with respect to each calendar quarter within 45 days after the end of each quarter. Distributions are based on available cash, as defined in the Partnership Agreement, which includes all cash and cash equivalents of the Partnership and working capital borrowings less reserves established by the General Partner.

Pursuant to the Partnership Agreement, the General Partner receives two percent of all cash distributions in regard to its general partner interest and is also entitled to incentive distributions as described below. The unitholders receive the remaining portion of the cash distribution.

The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our General Partner after providing for Class B distributions based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its IDRs and two percent general partner interest and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The percentage interest distributions to the General Partner illustrated below that are in excess of its two percent general partner interest represent the IDRs.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distribution	
		Common Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98%	2%
First Target Distribution	above $0.45 up to $0.81	98%	2%
Second Target Distribution	above $0.81 up to $0.88	85%	15%
Thereafter	above $0.88	75%	25%

The following table provides information about our distributions (in millions, except per unit distributions amounts).

Declaration Date	Payment Date	Per Unit Distribution	Limited Partners		General Partner		Total Cash Distribution
			Common Units	Class B Units(b)	2%	IDRs(a)	
1/23/2017	2/14/2017	$0.94	$64	$22	$2	$2	$90
4/25/2017	5/15/2017	$0.94	$65	$—	$1	$2	$68
7/20/2017	8/11/2017	$1.00	$69	$—	$2	$3	$74
10/24/2017	11/14/2017	$1.00	$70	$—	$1	$3	$74
1/23/2018	2/13/2018	$1.00	$71	$15	$2	$3	$91
5/1/2018	5/15/2018	$0.65	$46	$—	$1	$—	$47
7/26/2018	8/15/2018	$0.65	$46	$—	$1	$—	$47
10/23/2018	11/14/2018	$0.65	$46	$—	$1	$—	$47
1/22/2019	2/11/2019	$0.65	$46	$13	$1	$—	$60
4/23/2019	5/13/2019	$0.65	$46	$—	$1	$—	$47
7/23/2019	8/14/2019	$0.65	$46	$—	$1	$—	$47
10/22/2019	11/14/2019	$0.65	$46	$—	$1	$—	$47
1/21/2020(c)	2/14/2020(c)	$0.65	$46	$8	$1	$—	$55

(a) The distributions paid during the year ended December 31, 2019 included no incentive distributions to the General Partner (2018 — $3 million, 2017 — $10 million).

(b) The Class B units issued by us on April 1, 2015 represent limited partner interests in us and entitle TC Energy to an annual distribution which is an amount based on 30 percent of GTN's annual distributions after exceeding certain annual thresholds and adjustments (refer to Note 11)

(c) On February 14, 2020, we paid a cash distribution of $0.65 per unit on our outstanding common units to unitholders of record at the close of business on January 31, 2020 (refer to Note 24).

NOTE 16 CHANGE IN OPERATING WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2019**	**2018**	**2017**
Change in accounts receivable and other	**9**	(6)	4
Change in inventory	**(2)**	—	—
Change in other current assets	**—**	(1)	2
Change in accounts payable and accrued liabilities(a)	**(11)**	3	(7)
Change in accounts payable to affiliates	**2**	1	(3)
Change in accrued interest	**(1)**	—	2
Change in operating working capital	**(3)**	(3)	(2)

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

NOTE 17 TRANSACTIONS WITH MAJOR CUSTOMERS

For the year ended December 31, 2019, no customer accounted for more than 10 percent of our consolidated revenue and trade accounts receivable.

At December 31, 2018, Tenaska owed the Partnership approximately $4 million, which was approximately 10 percent of our consolidated trade accounts receivable. As noted under Note 6, in 2018, Tenaska assumed Anadarko's ship-or-pay contract obligation on Bison. After assuming the transportation obligation, Bison accepted an offer from Tenaska to terminate its contract. For the year ended December 31, 2018, revenues from both Anadarko and Tenaska amounted to $144 million.

At December 31, 2017, Anadarko owed the Partnership approximately $4 million, which was approximately 10 percent of our consolidated trade accounts receivable. For the year ended December 31, 2017, revenues from Anadarko amounted to $48 million, which was approximately 10 percent of our consolidated revenue.

NOTE 18 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 the conduct of 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. Total costs charged to the Partnership by the General Partner was $4 million for the year ended December 31, 2019 (2018 — $4 million; 2017 — $4 million)

As operators of most of our pipelines (except Iroquois and the Pipeline facilities jointly owned with MNE on PNGTS (the Joint Facilities)), TC Energy's subsidiaries provide capital and operating services to our pipeline systems. TC Energy'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. The Joint Facilities are operated by MNOC. Therefore, Iroquois and the Joint Facilities do not receive capital and operating services from TC Energy.

Capital and operating costs charged to our pipeline systems, except for Iroquois, for the years ended December 31, 2019, 2018 and 2017 by TC Energy's subsidiaries and amounts payable to TC Energy's subsidiaries at December 31, 2019 and 2018 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2019**	**2018**	**2017**
Capital and operating costs charged by TC Energy's subsidiaries to:			
Great Lakes[(a)]	**47**	44	36
Northern Border[(a)]	**39**	36	43
PNGTS[(a)]	**7**	9	9
GTN	**45**	34	34
Bison	**2**	6	6
North Baja	**5**	4	4
Tuscarora	**4**	4	4
Impact on the Partnership's net income attributable to controlling interests:			
Great Lakes	**20**	19	15
Northern Border	**18**	16	16
PNGTS	**4**	5	5
GTN	**33**	28	29
Bison	**2**	6	6
North Baja	**4**	4	4
Tuscarora	**4**	4	4

December 31 (millions of dollars)	**2019**	**2018**
Amount payable to TC Energy's subsidiaries for costs charged in the year by:		
Great Lakes[(a)]	**5**	3
Northern Border[(a)]	**4**	3
PNGTS[(a)]	**1**	1
GTN	**5**	4
Bison	**—**	1
North Baja	**1**	—
Tuscarora	**—**	1

(a) Represents 100 percent of the costs.

Great Lakes

Great Lakes earns significant transportation revenues from TC Energy and its affiliates. For the year ended December 31, 2019, Great Lakes earned 73 percent of its transportation revenues from TC Energy and its affiliates (2018 — 73 percent; 2017 — 57 percent). Additionally, included in Great Lakes' other revenues were cost recovery charges to its affiliates for use of office space in the building it owns (which was sold to a third party in the third quarter of 2019) and comprised less than one percent of its total revenues in 2019 and 2018 (2017 — 1 percent).

At December 31, 2019, $19 million was included in Great Lakes' receivables in regard to the transportation contracts with TC Energy and its affiliates (December 31, 2018 — $18 million).

During 2017, Great Lakes operated under a FERC approved 2013 rate settlement that included a revenue sharing mechanism requiring Great Lakes to share with its customers certain percentages of any qualifying revenues earned above certain ROEs (the 2017 Great Lakes Settlement). During the second quarter of 2018, the refund was settled with customers and a significant portion was refunded to affiliates. Under the terms of the 2017 Great Lakes Settlement, beginning in 2018, the revenue sharing mechanism was eliminated.

Great Lakes has a cash management agreement with TC Energy whereby Great Lakes' funds are pooled with other TC Energy affiliates. The agreement also gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for Great Lakes' operating needs. At December 31, 2019 and 2018, Great Lakes had outstanding receivables from this arrangement amounting to $34 million and $36 million, respectively.

Great Lakes has a long-term transportation agreement with TC Energy's Canadian Mainline that commenced on November 1, 2017 for a ten-year period and allows TC Energy to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from TC Energy's long-term fixed price service on its Canadian Mainline that was launched in 2017. For the year ended December 31, 2019, the total revenue earned by Great Lakes on this contract was $76 million. (2018 — $76 million; 2017 — $13 million).

In 2018, Great Lakes executed long-term transportation capacity contracts with its affiliate, ANR Pipeline Company (ANR). The contracts are for a term of 15 years from November 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, 2020 for any reason and (ii) any time before April 2021, if ANR is not able to secure the required regulatory approval related to anticipated expansion projects.

PNGTS

For the three years ended December 31, 2019, PNGTS provided transportation to TransCanada Energy Ltd., a subsidiary of TC Energy and earned revenues of less than $1 million in 2019 (2018 — $1 million; 2017 — $1 million). At December 31, 2019 and 2018, PNGTS had no outstanding receivables from TransCanada Energy Ltd. in the consolidated balance sheets.

In connection with the Portland XPress expansion project (PXP), which was designed to be phased in over a three-year time period, PNGTS has entered into an arrangement with its affiliates regarding the construction of certain facilities on their systems that will be required to fulfill future contracts on the PNGTS system. PXP Phases I and II were placed into service on November 1, 2018 and November 1, 2019, respectively. Phase III is estimated to be in service on November 1, 2020. In the event the expansions terminate prior to their in-service dates, PNGTS will be required to reimburse its affiliates for any costs incurred related to the development of these facilities, which was over $140 million prior to November 1, 2019. As a result of placing the TC Energy facilities associated with the Phase II volumes in service, PNGTS' obligation to reimburse development costs with respect to Phases I and II terminated.

Going forward, in the event the Phase III expansion terminates prior to its in-service date, PNGTS will only be obligated to reimburse costs incurred by TC Energy in relation to Phase III, which was $0.6 million at December 31, 2019 and estimated to be approximately $8.0 million by November 1, 2020, when Phase III goes into service.

NOTE 19 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2019 and 2018:

Quarter ended (millions of dollars except per common unit amounts)	**Mar 31**	**Jun 30**	**Sept 30**	**Dec 31**
2019				
Transmission revenues	**113**	**93**	**93**	**104**
Equity earnings	**54**	**30**	**31**	**45**
Net income (loss)	**100**	**57**	**59**	**82**
Net income (loss) attributable to controlling interests	**93**	**55**	**56**	**76**
Net income (loss) per common unit	**$1.28**	**$0.75**	**$0.76**	**$0.95**
Cash distributions paid to common units	**47**	**47**	**47**	**47**
Cash distribution paid to Class B units	**13**	**—**	**—**	**—**
2018				
Transmission revenues	115	111	103[(b)]	220[(c)]
Equity earnings	59	36	34	44
Net income	102	75	65	(406)
Net income attributable to controlling interests	96	73	62	(413)
Net income per common unit	$1.32	$1.00	$0.79	$(5.80)
Cash distributions paid to common units	76[(a)]	47	47	47
Cash distribution paid to Class B units	15	—	—	—

(a) Distributions paid to common units includes our general partner's two percent share and IDRs.

(b) Net of a $9 million provision for revenue sharing recognized as part of the 2018 GTN Settlement, in which GTN agreed to issue a refund of $10 million allocated amongst its firm customers from January 1, 2018 to October 31, 2018 (Refer to Note 4).

(c) Net of a $1 million provision for revenue sharing recognized as part of the 2018 GTN Settlement, in which GTN agreed to issue a refund of $10 million allocated amongst its firm customers from January 1, 2018 to October 31, 2018 (Refer to Note 4). This amount also includes the $97 million proceeds received by Bison from the termination of certain customer contracts (Refer to Note 6).

NOTE 20 FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, Fair Value Measurements and *Disclosures*, fair value measurements are characterized in one of three levels based upon the input 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, accrued interest and short-term debt are classified as Level 1 in fair value hierarchy. Accordingly, the carrying values 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 long-term 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.

The Partnership has classified the fair value of natural gas imbalances as a Level 2 of the fair value hierarchy for fair value disclosure purposes, as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance.

Long-term debt is recorded at amortized cost and classified as a Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified as a 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 December 31, 2019 and December 31, 2018 was $2,111 million and $2,101 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 mature on October 2, 2022 and 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. The fixed weighted average interest rate on these instruments is 3.26 percent. On June 26, 2019, in conjunction with the Partnership's $50 million repayment on its 2013 Term Loan Facility, the Partnership also terminated an equivalent amount in interest rate swaps that were used to hedge this facility at an unwind rate of 2.81 percent (See also Note 9).

At December 31, 2019, the fair value of the interest rate swaps accounted for as cash flow hedges was a liability of $6 million (on both gross and net basis) (December 31, 2018 — asset of $8 million), the net change of which is recognized in other comprehensive income. For the year ended December 31, 2019, the net realized gain related to interest rate swaps was $1 million and was included in financial charges and other (2018 — $2 million, 2017 — nil). Refer to Note 13 — Financial Charges and Other.

The Partnership has no master netting agreements; however, its contracts contain 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 December 31, 2019 and 2018.

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its 5.90% 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 AOCI as of the termination date. At December 31, 2018, and as a result of the repayment of the 5.90% Senior Secured Notes, the remaining balance of the $20.9 million realized loss in AOCI included in other comprehensive income at the termination date was fully amortized against earnings. For the years ended December 31, 2018 and 2017, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $1 million for each year.

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 cash and cash equivalents and receivables, 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 December 31, 2019, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2019, no customer accounted for more than 10 percent of our consolidated revenues and accounts receivable, respectively (refer also to Note 17 for more details).

(c) Other

The estimated fair value measurements on Tuscarora's goodwill, Bison's long-lived assets and our equity investment in Great Lakes, are classified as Level 3. In the determination of fair value utilized in the recoverability assessments for the respective assets, we used internal forecasts on expected future cash flows and applied appropriate discount rates. The determination of expected future cash flows involved significant assumptions and estimates as discussed more fully in Notes 4 (Tuscarora), 5 (Great Lakes) and 7 (Bison).

NOTE 21 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2019**	**2018**
Trade accounts receivable, net of allowance of nil	**37**	44
Imbalance receivable from affiliates	**—**	2
Other	**6**	2
	43	48

NOTE 22 CONTINGENCIES

The Partnership and its pipeline systems are subject to various legal proceedings in the ordinary course of business. Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with ASC 450, *Contingencies*. We base these estimates on currently available facts and the estimates of the ultimate outcome or resolution. Actual results may differ from estimates resulting in an impact, positive or negative, on earnings and cash flow. Contingencies that might result in a gain are not accrued in our consolidated financial statements.

At December 31, 2019, 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 23 VARIABLE INTEREST ENTITIES (VIEs)

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 2018 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. Information related to the Partnership's VIEs are disclosed below:

Consolidated VIEs

The Partnership's consolidated VIEs consist of the intermediate partnerships and mainly 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 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, Iroquois, and effective December 31, 2018, North Baja due to their third-party debt.

Beginning October 31, 2019, the Partnership owns its pipeline assets directly as a result of the dissolution of the three ILPs and Intermediate GP as disclosed under Note 1 — Organization. As a result, the Partnership's remaining VIE pertains to its variable interest in Great Lakes, which is accounted as an equity investment since the Partnership is not the primary beneficiary.

The following table presents the total assets and liabilities of these entities that are included in the Partnership's consolidated balance sheets:

(millions of dollars)	December 31, 2019	December 31, 2018[(a)]
ASSETS (LIABILITIES)		
Cash and cash equivalents	—	16
Accounts receivable and other	—	39
Inventories	—	8
Other current assets	—	6
Equity investments	**491**[(b)]	1,196
Property, plant and equipment	—	1,240
Other assets	—	1
Accounts payable and accrued liabilities	—	(33)
Accounts payable to affiliates, net	—	(40)
Distributions payable	—	—
Accrued interest	—	(2)
Current portion of long-term debt	—	(36)
Long-term debt	—	(341)
Other liabilities	—	(27)
Deferred state income tax	—	(9)

(a) Bison, an asset held through our consolidated VIEs, is excluded at December 31, 2018 as the assets of this entity can be used for purposes other than the settlement of the VIE's obligations.

(b) Equity investment on Great Lakes (Refer to Note 5)

NOTE 24 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through February 20, 2020, 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.

Partnership

On January 21, 2020, the board of directors of our General Partner declared the Partnership's fourth quarter 2019 cash distribution in the amount of $0.65 per common unit and was paid on February 14, 2020 to unitholders of record as of January 31, 2020. 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 TC Energy as holder of 11,287,725 common units) and $1 million to the General Partner for its two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the fourth quarter 2019.

On January 21, 2020, the board of directors of our General Partner declared its annual distribution to Class B units in the amount of $8 million which was paid on February 14, 2020. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2019 less $20 million and the Class B Reduction.

Northern Border

Northern Border declared its December 2019 distribution of $18 million on January 10, 2020, of which the Partnership received its 50 percent share or $9 million on January 31, 2020.

Northern Border declared its January 2020 distribution of $19 million on February 11, 2020, of which the Partnership will receive its 50 percent share or $9 million on February 28, 2020.

Great Lakes

Great Lakes declared its fourth quarter 2019 distribution of $34 million on January 10, 2020, of which the Partnership received its 46.45 percent share or $16 million on January 31, 2020.

Iroquois

Iroquois declared its fourth quarter 2019 distribution of $27 million in February 2020, and the Partnership will receive its 49.34 percent share or $13 million on March 30, 2020. The $13 million includes our proportionate share of Iroquois' unrestricted cash amounting to $2.6 million (refer to Note 8).

PNGTS

PNGTS declared its fourth quarter 2019 distribution of $18 million on January 15, 2020, of which $7 million was paid to its non-controlling interest owner on January 31, 2020.

Independent Auditors' Report

The Management Committee
Northern Border Pipeline Company:

We have audited the accompanying financial statements of Northern Border Pipeline Company, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, comprehensive income, changes in partners' equity, and cash flows for the years in the three-year period ended December 31, 2019, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northern Border Pipeline Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP
Houston, Texas
February 14, 2020

NORTHERN BORDER PIPELINE COMPANY

Balance sheets

December 31, 2019 and 2018 (In thousands)	**2019**	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	**$20,667**	9,599
Accounts receivable	**24,418**	25,641
Related party receivables	**4,391**	3,271
Materials and supplies	**5,706**	5,612
Prepaid expenses and other	**2,783**	2,132
Total current assets	**57,965**	46,255
Property, plant and equipment:		
In-service natural gas transmission plant	**2,633,800**	2,638,014
Construction work in progress	**1,601**	2,866
Right of use asset	**156**	—
Total property, plant and equipment	**2,635,557**	2,640,880
Less: Accumulated provision for depreciation and amortization	**1,646,711**	1,604,566
Property, plant and equipment, net	**988,846**	1,036,314
Other assets:		
Regulatory assets	**12,436**	13,215
Total assets	**$1,059,247**	1,095,784
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	**$3,663**	3,298
Related party payables	**4,421**	3,680
Accrued taxes other than income	**18,369**	19,306
Accrued interest	**4,986**	4,731
Customer advances for construction	**10,517**	2,730
Other current liabilities	**22**	—
Total current liabilities	**41,978**	33,745
Long-term debt, net	**364,352**	264,455
Deferred credits and other liabilities		
Regulatory liability	**33,219**	29,598
Other	**5,280**	4,740
Total deferred credits and other liabilities	**38,499**	34,338
Total liabilities	**444,829**	332,538
Partners' equity:		
Partners' capital	**615,052**	764,209
Accumulated other comprehensive loss	**(634)**	(963)
Total partners' equity	**614,418**	763,246
Total liabilities and partners' equity	**$1,059,247**	1,095,784

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

NORTHERN BORDER PIPELINE COMPANY

Statements of income

Years ended December 31, 2019, 2018, and 2017 (In thousands)	2019	2018	2017
Operating revenue	**$300,221**	289,418	291,396
Operating expenses:			
Operations and maintenance	**60,428**	54,576	54,374
Depreciation and amortization	**61,588**	60,492	59,426
Taxes other than income	**22,539**	23,892	23,480
Operating expenses	**144,555**	138,960	137,280
Operating income	**155,666**	150,458	154,116
Interest expense:			
Interest expense	**21,727**	19,943	22,257
Interest expense capitalized	**(37)**	(101)	(176)
Interest expense, net	**21,690**	19,842	22,081
Other income (expense):			
Allowance for equity funds used during construction	**318**	623	573
Other income	**3,805**	4,505	3,936
Other expense	**(357)**	(37)	(238)
Other income, net	**3,766**	5,091	4,271
Net income to partners	**$137,742**	135,707	136,306

NORTHERN BORDER PIPELINE COMPANY

Statements of comprehensive income

Years ended December 31, 2019, 2018, and 2017 (In thousands)	**2019**	**2018**	**2017**
Net income to partners	**$137,742**	135,707	136,306
Other comprehensive income:			
Changes associated with hedging transactions	**329**	306	285
Total comprehensive income	**$138,071**	136,013	136,591

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

NORTHERN BORDER PIPELINE COMPANY

Statements of cash flows

Years ended December 31, 2019, 2018, and 2017 (In thousands)	**2019**	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income to partners	**$137,742**	135,707	136,306
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	**61,588**	60,492	59,426
Allowance for equity funds used during construction	**(318)**	(623)	(573)
Changes in components of working capital	**578**	(5,909)	(1,411)
Amortization of debt expense	**226**	704	795
Other	**1,708**	2,208	(389)
Total adjustments	**63,782**	56,872	57,848
Net cash provided by operating activities	**201,524**	192,579	194,154
CASH FLOWS USED IN INVESTING ACTIVITIES:			
Capital expenditures	**(11,344)**	(31,269)	(27,054)
Other	**7,787**	646	(722)
Net cash used in investing activities	**(3,557)**	(30,623)	(27,776)
CASH FLOWS USED IN FINANCING ACTIVITIES:			
Equity contributions from partners	**—**	—	166,000
Distributions to partners	**(286,899)**	(166,367)	(165,903)
Proceeds from issuance of debt	**100,000**	—	—
Repayment of debt	**—**	—	(166,000)
Net cash used in financing activities	**(186,899)**	(166,367)	(165,903)
Net change in cash and cash equivalents	**11,068**	(4,411)	475
Cash and cash equivalents at beginning of year	**9,599**	14,010	13,535
Cash and cash equivalents at end of year	**$20,667**	9,599	14,010
SUPPLEMENTAL DISCLOSURE FOR CASH FLOW INFORMATION:			
Cash paid for interest, net of amount capitalized	**$20,857**	19,098	21,301
Accruals for property, plant and equipment	**635**	1,479	2,592
CHANGES IN COMPONENTS OF WORKING CAPITAL:			
Accounts receivable	**$1,223**	(903)	(1,254)
Related party receivables	**(1,120)**	(222)	454
Materials and supplies	**(94)**	(396)	511
Prepaid expenses and other	**(699)**	(167)	319
Accounts payable	**1,209**	(5,834)	(1,702)
Related party payables	**741**	2,119	709
Accrued taxes other than income	**(937)**	(303)	(676)
Accrued interest	**255**	40	(15)
Other current liabilities	**—**	(243)	243
Total	**$578**	(5,909)	(1,411)

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

NORTHERN BORDER PIPELINE COMPANY

Statements of changes in partners' equity

(In thousands)	TC PipeLines, LP	ONEOK Northern Border Pipeline Company Holdings, L.L.C.	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
Partners' equity at December 31, 2016	$329,233	329,233	(1,554)	656,912
Net income to partners	68,153	68,153	—	136,306
Changes associated with hedging transactions	—	—	285	285
Contributions from partners	83,000	83,000	—	166,000
Distributions to partners	(82,952)	(82,951)	—	(165,903)
Partners' equity at December 31, 2017	$397,434	397,435	(1,269)	793,600
Net income to partners	67,854	67,853	—	135,707
Changes associated with hedging transactions	—	—	306	306
Distributions to partners	(83,184)	(83,183)	—	(166,367)
Partners' equity at December 31, 2018	$382,104	382,105	(963)	763,246
Net income to partners	68,871	68,871	—	137,742
Changes associated with hedging transactions	—	—	329	329
Distributions to partners	(143,449)	(143,450)	—	(286,899)
Partners' equity at December 31, 2019	$307,526	307,526	(634)	614,418

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

NORTHERN BORDER PIPELINE COMPANY

Notes to financial statements

Years ended December 31, 2019 and 2018

1. DESCRIPTION OF BUSINESS

Northern Border Pipeline Company (the Partnership) is a Texas general partnership formed in 1978. The Partnership owns a 1,263-mile natural gas transmission pipeline system, which includes an additional 149 pipeline miles parallel to the original system, extending from the United States-Canadian border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana. The partners and ownership percentages were as follows:

Partner	Ownership
ONEOK Northern Border Pipeline Company Holdings, L.L.C.	50%
TC PipeLines, LP	50%

Previously, TC PipeLines Intermediate Limited Partnership (TCILP) and ONEOK Partners Intermediate Limited Partnership (ONEOK LP) each held a 50 percent interest in the Partnership. Effective October 31, 2019, TCILP transferred 100 percent of its 50 percent interest in the Partnership to its affiliate TC PipeLines, LP (TCP). On November 19, 2019, ONEOK LP transferred 100 percent of its 50 percent interest in the Partnership to its affiliate ONEOK Northern Border Pipeline Company Holdings, L.L.C.

TC PipeLines, LP (TCP) is an indirect subsidiary of TC Energy Corporation (TC Energy), formerly known as TransCanada Corporation. ONEOK Northern Border Pipeline Company Holdings, L.L.C. (ONEOK) is an indirect subsidiary of ONEOK, Inc.

The Partnership is managed by a Management Committee that consists of four members. Each partner designates two members and TCP designates one of its members as chairman.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Partnership's financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Certain prior year amounts have been reclassified to conform to the current year presentation.

(b) Use of Estimates

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

(c) Cash and Cash Equivalents

The Partnership's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

(d) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest, except for those receivables subject to late charges. The Partnership maintains an allowance for doubtful accounts for estimated losses on accounts receivable, if it is determined the Partnership will not collect all or part of the outstanding receivable balance. The Partnership regularly reviews its allowance for doubtful accounts and establishes or adjusts the allowance as necessary using the specific-identification method. Account balances are charged to the allowance after all means of collection have been exhausted and the potential for recovery is no longer considered probable. Accounts written off in 2019 and 2018 were not material to the Partnership's financial statements.

(e) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and interconnecting parties at current index prices. Imbalances are settled in-kind, subject to the terms of the Partnership's tariff.

Imbalances due from others are reported on the balance sheets as trade accounts receivable and related party receivables. Imbalances owed to others are reported on the balance sheets as trade accounts payable and related party payables. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(f) Material and Supplies

The Partnership's inventories primarily consist of materials and supplies and are carried at lower of weighted average cost and net realizable value.

(g) Accounting for Regulated Operations

The Partnership's natural gas pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations*, provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. The Partnership evaluates the continued applicability of regulatory accounting, considering such factors as regulatory charges, the impact of competition, and the ability to recover regulatory assets as set forth in ASC 980. Accordingly, certain assets and liabilities that result from the regulated ratemaking process are reflected on the balance sheets as regulatory assets and regulatory liabilities.

The following table presents regulatory assets and liability at December 31, 2019 and 2018:

	December 31,		Remaining recovery/ settlement period
	2019	**2018**	
	(In thousands)		(Years)
Regulatory Assets			
Fort Peck lease option	**$11,513**	11,831	36
Pipeline extension project	**923**	1,384	2
Volumetric fuel tracker	**139**	182	(a)
Compressor usage surcharge	**—**	6	(b)
	12,575	13,403	
Less: Current portion included in Prepaid expenses and other	**139**	188	
	$12,436	13,215	
Regulatory Liabilities			
Negative salvage	**$31,966**	29,598	(c)
Compressor usage surcharge	**1,253**	—	(b)
	$33,219	29,598	

(a) Volumetric fuel tracker assets or liabilities are continuously settled with in-kind exchanges with customers

(b) Compressor usage surcharge is designed to track the recovery of the actual costs related to both electricity usage at the Partnership's electric compressors and compressor fuel use taxes imposed on the consumption of natural gas powered stations along the Partnership's pipeline system (refer to Note 4(b))

(c) Negative salvage accrued for estimated net costs of removal of transmission plant has a settlement period related to the estimated life of the assets (refer to Note 2(h))

(h) Property, Plant and Equipment

Property, plant and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs, such as labor and materials, and indirect costs, such as overhead, interest, and an equity return component on regulated businesses as allowed by the FERC, are capitalized. The Partnership capitalizes major units of property replacements or improvements and expenses minor items.

The Partnership uses the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The depreciation rate is applied to the total cost of the group until its net book value equals its salvage value. All asset groups are depreciated using depreciation rates approved in the Partnership's last rate proceeding. Currently, the Partnership's depreciation rates vary from 2% to 20% per year. Using these rates, the remaining depreciable life of these assets ranges from 1 to 35 years.

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as "negative salvage") and recognizes a regulatory liability in this respect in the balance sheets. Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by FASB ASC 410, *Accounting for Asset Retirement Obligations*. When property, plant and equipment are retired, the Partnership charges accumulated depreciation and amortization for the original cost of the assets in addition to the cost to remove, sell, or dispose of the assets, less their salvage value. The Partnership does not recognize a gain or loss unless an entire operating unit is sold or retired. The Partnership includes gains or losses on dispositions of operating units in income.

The Partnership capitalizes a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC). AFUDC is recorded based on the Partnership's average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheets.

(i) Long-Lived Assets

Long-lived assets, such as property, plant and equipment, and purchased intangible assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, the Partnership first compares undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values, and third-party independent appraisals, as considered necessary.

(j) Revenue Recognition

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 utilizes the practical expedient of recognizing revenue as invoiced. 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.

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. As of December 31, 2019, and 2018, there are no refund provisions reflected in these financial statements.

(k) Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. ASC 410-20 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long lived assets that result from the acquisition, construction, development, and/or normal use of the assets. ASC 410-20 also requires the Partnership to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is to be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

The fair value of a liability for an asset retirement obligation is recorded during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. The Partnership has determined that asset retirement obligations exist for certain of its transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system's life is not determinable with the degree of accuracy necessary to currently establish a liability for the obligations.

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system and intends to do so as long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2019 and 2018. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(l) Derivative Instruments and Hedging Activities

The Partnership recognizes all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

The Partnership only enters into derivative contracts that it intends to designate as a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). In a cash flow hedging relationship, the change in the fair value of the hedging derivative is reported as a component of other comprehensive income and reclassified into earnings as part of "interest expense" in the same period or periods during which the hedged transaction affects earnings or is reclassified immediately to net income when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In some instances, the derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

Prior to December 31, 2001, the Partnership terminated a series of interest rate derivatives in exchange for cash. These derivatives had previously been accounted for as hedges with $4.1 million recorded in accumulated other comprehensive loss (AOCL) as of the termination date. The previously recorded AOCL is currently being reclassified to "interest expense" using the effective interest method over the remaining term of the related hedged instrument, the Partnership's 2001 Senior Notes due 2021. At December 31, 2019, the remaining balance in AOCL that is left to be reclassified to earnings is $0.6 million, of which $0.4 million is expected to be reclassified in 2020.

The Partnership had no other derivative instruments during the year ended December 31, 2019.

(m) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective-interest rate method over the term of the related debt.

The Partnership amortizes premiums and discounts incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount. In addition, amortization of debt issuance costs, premiums, and discounts are reported as part of interest expense.

(n) Income Taxes

Income taxes are the responsibility of the partners and are not reflected in these financial statements.

(o) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable and certain accrued expenses, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments, fair value is estimated based upon market values (if applicable) or on the current interest rates available to the Partnership for debt with similar terms and remaining maturities. Judgment is required in developing these estimates.

3. ACCOUNTING CHANGES

(a) Changes in Accounting Policies effective January 1, 2019

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee 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 consolidated balance sheet for all leases with a term longer than twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statements of income. The new guidance does not make extensive changes to previous lessor accounting.

Under the new guidance, the Partnership determines if an arrangement is a lease at inception. Operating leases are recognized as ROU assets and included in Property, plant and equipment while corresponding liabilities are included in "Other current liabilities", and "Other long-term liabilities" on the balance sheets.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at commencement date. If the Partnership's leases do not have an implicate rate, the present value of future minimum payments, if any, will be determined using a rate that approximates the Partnership's borrowing cost. Operating lease expense is recognized on a straight-line basis over the lease term and included in "Operation and maintenance" expenses" in the statements of income.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption and recognize a cumulative-effect adjustment to the opening balance of equity in the period of adoption. This transition option allowed us to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

The Partnership elected available practical expedients and exemptions upon adoption which allowed us:

- not to reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and our accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- to not separate lease and non-lease components for all leases for which the Partnership is the lessee
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

In the application of the new guidance, assumptions and judgements are used to determine the following:

- whether a contract contains a lease and the duration of the lease term including exercising lease renewal options. The lease term for all of the Partnership's leases includes the non-cancellable period of the lease plus any additional periods covered by either the Partnership's option to extend (or not to terminate) the lease that the Partnership is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor; and
- the discount rate for the lease.

The standard did not impact the Partnership's previously reported results and did not have material impact on its financial statements at the date of adoption.

The primary change as a result of the adoption was the recognition of ROU assets and lease liabilities for operating leases, which were approximately $0.2 million at January 1, 2019. At December 31, 2019, the ROU assets and corresponding net present value of the lease liabilities were both $0.2 million. For the year ended December 31, 2019, the Partnership's operating lease costs were not material to the financial results. The weighted average remaining term and discount rate of the Partnership's operating leases are approximately 6.25 years and 4.12 percent, respectively.

Fair Value Measurement

In August 2018, the FASB issued new guidance that amends 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 of certain or all requirements is permitted. The Partnership elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material effect on the Partnership's financial statements.

(b) Future Accounting Changes

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. The adoption of this new guidance will not have a material impact on the Partnership's financial statements.

4. CONTINGENCIES AND COMMITMENTS

(a) Contingencies

The Partnership is subject to various legal proceedings in the ordinary course of business. The accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with *ASC 450, Contingencies*. The Partnership bases these estimates on currently available facts and the estimates of the ultimate outcomes or resolution. Actual results may vary from estimates resulting in an impact, positive or negative, on results of operations and cash flows. 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.

(b) Regulatory Matters

The FERC regulates the rates and charges for transportation of natural gas in interstate commerce. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's actual prudent historical cost investment. The rates and terms and conditions for service are found in each pipeline's FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

2018 FERC Actions

The Partnership has completed the regulatory filing that was required by FERC (see details below) to address the issues contemplated by Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act (2017 Tax Act) and certain FERC actions that began in March of 2018, namely FERC's Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that 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 quantified the rate impact of the 2017 Tax Act on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by Master Limited Partnerships (MLP), such as the Partnership:

Pipelines filing FERC Form No. 501-G had 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 guaranteed a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G showed 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 believed that using the limited Section 4 option would not result in just and reasonable rates. If the pipeline committed to file by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it did not believe the pipeline's rates must change; or
- Option 4: take no action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that had not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

2017 Rate Case, and subsequent limited section 4 rate reductions

The Partnership operates under a settlement approved by FERC effective January 1, 2018 (2017 Settlement). The 2017 Settlement provided for tiered rate reductions from January 1, 2018 to December 31, 2019 that equates to an overall rate reduction of 12.5% by January 1, 2020 when compared to the 2017 rates (10.5% by December 31, 2019 and additional 2% by January 1, 2020). The 2017 Settlement did not contain a moratorium and the Partnership is required to file new rates effective July 1, 2024. Effective February 1, 2019, FERC approved an additional 2% rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to the Partnership's limited NGA Section 4 filing. On April 4, 2019, the Partnership filed an amended settlement agreement that extended the 2% rate reduction implemented on February 1, 2019 to July 1, 2024 effective January 1, 2020 unless superseded by a subsequent rate case or settlement. On May 24, 2019, FERC approved the amended settlement agreement and the Partnership's 501-G proceeding was terminated.

Compressor Usage Surcharge

The compressor usage surcharge is designated to recover the actual costs of electricity at the Partnership's electric compressors and any compressor fuel use taxes imposed on its pipeline system. Any difference between the compressor usage surcharge collected and the actual costs for electricity and compressor fuel use taxes is recorded as either an increase to expense for an over-recovery of actual costs or as a decrease to expense for an under-recovery of actual costs and is included in operations and maintenance expense on the income statement and reported as current asset or current liability on the balance sheets. The compressor usage surcharge rate is adjusted annually. The current asset or current liability will reflect the net over or under recovery of actual compressor usage related costs at the date of the balance sheet. As of December 31, 2019, and 2018, the Partnership had recorded $1.3 million and nil million as regulatory liability, respectively, on the accompanying balance sheets for the net under recoveries of compressor usage related costs.

(c) Environmental Matters

The Partnership is not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

(d) Commitments

The Partnership makes payments under its right-of-way commitments. The Partnership's expense incurred for these commitments was $2.9 million for the year ended December 31, 2019, and $3.0 million for each of the years ended December 31, 2018, and 2017, respectively. The Partnership's future minimum payments on its rights-of-way commitments are as follows:

Year Ending (In thousands)	**Rights-of-Way**
2020	2,231
2021	2,565
2022	2,566
2023	2,566
2024	2,565
Thereafter	34,815
	$47,308

Approximately 90 miles of Partnership's pipeline system is located within the boundaries of the Fort Peck Indian Reservation in Montana. The Partnership has a pipeline rights-of-way commitment with the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation, the term of which expires in 2061. In conjunction with obtaining right-of-way access across tribal lands located within the exterior boundaries of the Fort Peck Indian Reservation, the Partnership also obtained right-of-way access across allotted lands located within the reservation boundaries. With the exception of one tract subject to a right-of-way grant expiring in 2035, the allotted lands are subject to a perpetual easement granted by the Bureau of Indian Affairs (BIA) for and on behalf of the individual allottees.

5. CREDIT FACILITIES AND LONG-TERM DEBT

The Partnership's long-term debt outstanding consisted of the following at December 31:

(In thousands)	**2019**	**2018**
2011 Credit Agreement — average interest rate of 3.226% at December 31, 2019; due 2024[(a)]	**$115,500**	15,500
2001 Senior Notes — 7.50%, due 2021	**250,000**	250,000
	365,500	265,500
Unamortized debt issuance costs	**(94)**	(143)
Unamortized debt expense	**(1,054)**	(902)
Total long-term debt, net	**$364,352**	264,455

(a) In June 2019, the Partnership borrowed an additional $100 million under its 2011 Credit Agreement to finance an additional cash distribution of $100 million, or $50 million to each partner.

On November 16, 2011, the Partnership entered into a $200 million amended and restated revolving credit agreement (2011 Credit Agreement) with certain financial institutions. The 2011 Credit Agreement is generally used by the Partnership to finance ongoing working capital needs and for other general business purposes, including capital expenditures. On October 1, 2019, the Partnership extended the 2011 Credit Agreement set to expire October 9, 2020 to October 1, 2024.

At December 31, 2019, the Partnership's outstanding borrowings under the 2011 Credit Agreement were $115.5 million, leaving $84.5 million available for future borrowings. The 2011 Credit Agreement have accordion features for an additional capacity of $100 million, subject to lender consent. At the Partnership's option, the interest rate on the outstanding borrowings may be the lenders' base rate or the London Interbank Offered Rate plus an applicable margin that is based on its long-term unsecured credit ratings.

Certain of the Partnership's long-term debt arrangements contain covenants that restrict the incurrence of secured indebtedness or liens upon property by the Partnership. Under the 2011 Credit Agreement, the Partnership is required to comply with certain financial, operational and legal covenants. Among other things, the Partnership is required to maintain a leverage ratio of no more than 5.00 to 1.00. Pursuant to the 2011 Credit Agreement, if one or more specified material acquisitions are consummated, the permitted leverage ratio is increased to 5.50 to 1.00 for the first two full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2011 Credit Agreement may become immediately due and payable.

At December 31, 2019, the Partnership was in compliance with all of its financial covenants.

The Partnership's long-term debt repayments consisted of the following at December 31, 2019 (in thousands of dollars):

Year Ending	
2020	—
2021	250,000
2022	—
2023	—
2024	115,500
	$365,500

6. FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurement*, fair value measurements are characterized in one of three levels based upon the input 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 the Partnership has 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, accrued interest, all current receivable and payable accounts, except for natural gas imbalances are classified as Level 1 in fair value hierarchy. Accordingly, the carrying values approximate their fair values because of the short maturity or duration of these instruments.

The Partnership's natural gas imbalances, which are reported as part of accounts receivable, accounts payable and related party accounts, are classified as a Level 2 in the "Fair Value Hierarchy," as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance. Natural gas imbalances represent the difference between the amount of natural gas delivered to or received from a pipeline system and the amount of natural gas scheduled to be delivered or received at current market prices. The Partnership records these imbalances at fair value by applying the difference between the measured quantities of natural gas delivered to or received from its shippers and operators to the current average of the Northern Ventura index price and the Chicago city-gates index price. For the year ended December 31, 2019, the total estimated fair value of our natural gas imbalance was a net payable of approximately $1.5 million. (2018 — net receivable of $0.2 million). For the year ended December 31, 2019, the total estimated fair value of our related party natural gas imbalance was a net receivable of approximately $0.6 million. (2018 — net payable of $0.3 million).

For the year ended December 31, 2019, the fair value of the Partnership's long term debt was $381.6 million (2018 — $286.3 million) The fair value was estimated based on quoted market prices for the same or similar debt instruments with similar terms and remaining maturities, which is classified as Level 2 in the "Fair Value Hierarchy", where the fair value is determined by using valuation techniques that refer to observable market data.

7. REVENUES

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers 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 was prepared under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP".

(a) Disaggregation of Revenues

For the years ended December 31, 2019 and 2018, effectively all of the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2(j).

(b) Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under Accounts receivable in the balance sheet. Additionally, our accounts receivable represents the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

(c) Right to invoice practical expedient

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 capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied.

8. TRANSACTIONS WITH MAJOR CUSTOMERS

The following table represents the shippers providing significant operating revenues to the Partnership for the year ended December 31 (in thousands):

	2019	2018	2017
ONEOK Rockies[(a)]	**$39,549**	29,425	31,501
Tenaska Marketing Ventures	**42,032**	38,744	28,747
Sequent Energy	**20,297**	27,806	34,558
BP Canada Energy Marketing Group	**23,112**	27,538	30,186

(a) ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), is a subsidiary of ONEOK Inc.

The following table represents the amounts in the Partnership's trade or related party accounts receivable for shippers with accounts receivable balances greater than 10 percent of the Partnership's accounts receivable (in thousands).

	2019	2018
ONEOK Rockies[(a)]	**$3,735**	3,203
Tenaska Marketing Ventures	**3,337**	4,218

(a) ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), is a subsidiary of ONEOK Inc.

9. TRANSACTIONS WITH RELATED PARTIES

The day-to-day management of the Partnership's affairs is the responsibility of TransCanada Northern Border, Inc., a wholly owned subsidiary of TC Energy, (TransCanada Northern Border) pursuant to an operating agreement between TransCanada Northern Border and the Partnership effective April 1, 2007 (as amended). TransCanada Northern Border utilizes the services of TC Energy and its affiliates for management services related to the Partnership. The Partnership is charged for the capital, salaries, benefits and expenses of TC Energy and its affiliates attributable to the Partnership's operations. For the years ended December 31, 2019, 2018, and 2017, the Partnership's charges from TC Energy and its affiliates totaled approximately $39.2 million, $35.6 million, and $43.3 million, respectively. The impact of these charges on the Partnership's income was $36.3 million, $32.2 million, and $31.3 million, respectively. At December 31, 2019 and 2018, the Partnership owed $3.6 million and $3.3 million, respectively, to these affiliates classified to related party accounts on the balance sheets.

For the years ended December 31, 2019, 2018, and 2017, the Partnership had contracted firm capacity held by one customer affiliated with one of the Partnership's general partners. See Note 8 — Transactions with Major Customers for details regarding revenues and outstanding accounts receivable balances with ONEOK Rockies.

10. CASH DISTRIBUTION AND CONTRIBUTION POLICY

The Partnership's General Partnership Agreement provides that distributions to its partners are to be made on a pro rata basis according to each partner's capital account balance. The Partnership's Management Committee has the responsibility to determine the amount and timing of the distributions to its partners including equity contributions and the funding of growth capital expenditures. In addition, any inability to refinance maturing debt will be funded by equity contributions. Any changes to, or suspension of, the Partnership's cash distribution policy requires the unanimous approval of the Management Committee. The Partnership's cash distributions are equal to 100 percent of its distributable cash flow as determined from its financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. The Partnership paid monthly distributions approximately one month following the end of each reported month.

For the years ended December 31, 2019, 2018, and 2017, the Partnership paid distributions to its general partners of $286.9 million, including the distribution of $100 million from the proceeds of additional borrowings under the 2011 Credit Agreement (see Note 5), $166.4 million, and $165.9 million, respectively. In 2017, the Partnership received contributions from its partners of $166 million, $83 million each, which was used as a payment on the 2011 Credit Agreement.

11. SUBSEQUENT EVENTS

On January 10, 2020, the Partnership declared a cash distribution in the amount of $18.1 million. The distribution was paid on January 31, 2020.

On February 11, 2020, the Partnership declared a cash distribution in the amount of $18.8 million. The distribution will be paid on February 28, 2020.

Subsequent events have been assessed through February 14, 2020, which is the date the financial statements were issued, and we concluded there were no events or transactions during this period that would require recognition or disclosure in the financial statements other than those already reflected.

Independent Auditors' Report

The Partners and the Management Committee
Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying financial statements of Great Lakes Gas Transmission Limited Partnership, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, partners' capital, and cash flows for the years in the three-year period ended December 31, 2019, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP
Houston, Texas
February 14, 2020

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Balance sheets

December 31, 2019 and 2018 (In Thousands)	2019	2018
ASSETS		
Current assets:		
Cash and cash equivalents	**$39**	49
Demand loan receivable from related party	**34,262**	35,934
Accounts receivable:		
Trade	**7,016**	8,582
Related parties	**19,262**	18,754
Materials and supplies	**9,850**	9,951
Other	**1,858**	1,504
Total current assets	**72,287**	74,774
Property, plant, and equipment:		
Property, plant, and equipment	**2,130,615**	2,116,001
Construction work in progress	**3,129**	7,741
	2,133,744	2,123,742
Less accumulated depreciation and amortization	**(1,448,825)**	(1,434,748)
Total property, plant, and equipment, net	**684,919**	688,994
Total assets	**$757,206**	763,768
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable:		
Trade	**$6,395**	4,098
Related parties	**5,108**	3,815
Current maturities of long-term debt	**21,000**	21,000
Taxes payable (other than income)	**7,989**	8,184
Accrued interest	**5,554**	5,912
Other current liabilities	**8,434**	3,919
Total current liabilities	**54,480**	46,928
Long-term debt, net of current maturities	**197,817**	218,782
Regulatory liabilities	**5,948**	3,664
Other noncurrent liabilities	**5**	220
Partners' capital	**498,956**	494,174
Total liabilities and partners' capital	**$757,206**	763,768

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Statements of income and partners' capital

Years ended December 31, 2019, 2018, and 2017 (In Thousands)	**2019**	**2018**	**2017**
Operating revenues, *net (Note 8)*	**$237,894**	245,646	181,487
Operating expenses:			
Operation and maintenance	**67,996**	56,613	54,885
Depreciation and amortization	**31,954**	31,813	29,474
Taxes, other than income	**10,848**	11,651	10,830
Total operating expenses	**110,798**	100,077	95,189
Operating income	**127,096**	145,569	86,298
Interest and debt expense			
Interest expense	**17,747**	19,378	20,916
Interest expense capitalized	**(119)**	(184)	(72)
Interest expense, net	**17,628**	19,194	20,844
Other income			
Allowance for equity funds used during construction	**411**	308	116
Other income	**1,203**	979	749
Other income, net	**1,614**	1,287	865
Net income	**$111,082**	127,662	66,319
Partners' capital:			
Balance at beginning of year	**$494,174**	473,112	462,293
Net income	**111,082**	127,662	66,319
Distributions to partners	**(127,300)**	(125,600)	(74,500)
Contributions from partners	**21,000**	19,000	19,000
Balance at end of year	**$498,956**	494,174	473,112

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Statements of cash flows

Years ended December 31, 2019, 2018, and 2017 (In Thousands)	**2019**	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$111,082**	127,662	66,319
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**31,954**	31,813	29,474
Allowance for funds used during construction, equity	**(411)**	(308)	(116)
Gain on sale of property, plant and equipment	**(780)**	—	—
Amortization of debt issuance cost, reported as part of interest expense	**35**	29	41
Asset and liability changes:			
Accounts receivable	**1,058**	309	(1,109)
Other current assets	**(253)**	3,590	(2,608)
Accounts payable	**2,705**	(3,207)	(1,792)
Provision for revenue sharing refund	**—**	(44,722)	32,401
Provision for rate refund	**—**	(2,851)	7,972
Other current liabilities	**3,962**	2,329	(3,144)
Noncurrent liabilities	**(215)**	8	(14)
Net cash provided by operating activities	**149,137**	114,652	127,424
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant, and equipment	**(30,234)**	(17,178)	(13,814)
Net change in demand loan receivable from related party	**1,672**	28,106	(36,896)
Proceeds from sale of property, plant and equipment	**6,735**	—	—
Other	**(20)**	25	(2,209)
Net cash provided by (used in) investing activities	**(21,847)**	10,953	(52,919)
CASH FLOWS USED IN FINANCING ACTIVITIES:			
Contributions from partners	**21,000**	19,000	19,000
Payments for retirement of long-term debt	**(21,000)**	(19,000)	(19,000)
Distributions to partners	**(127,300)**	(125,600)	(74,500)
Net cash used in financing activities	**(127,300)**	(125,600)	(74,500)
Net change in cash and cash equivalents	**(10)**	5	5
Cash and cash equivalents at beginning of year	**49**	44	39
Cash and cash equivalents at end of year	**$39**	49	44
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$17,950**	19,599	20,791
Accruals for property, plant and equipment	**$2,791**	1,886	1,497

See accompanying notes to financial statements.

Notes to financial statements

December 31, 2019 and 2018

(1) DESCRIPTION OF BUSINESS

Great Lakes Gas Transmission Limited Partnership (the Partnership) is a Delaware limited partnership that owns 2,115 miles of natural gas pipeline system, which transports natural gas for delivery to wholesale customers in the midwestern and northeastern United States (U.S.) and eastern Canada. The partners' ownership percentages in the Partnership at December 31, 2019 were as follows:

	Ownership percentage
General Partners:	
TransCanada GL, Inc.	46.45
TC Pipelines, LP (TCP)	46.45
Limited Partner:	
Great Lakes Gas Transmission Company	7.10

Previously, TC GL Intermediate Limited Partnership held a 46.45 percent interest in the Partnership. Effective October 31, 2019, TC GL Intermediate Limited Partnership transferred 100 percent of its ownership of the Partnership to its related party, TC Pipelines, LP (TCP).

Great Lakes Gas Transmission Company (the Company), TransCanada GL Inc., and TCP) are wholly owned indirect subsidiaries of TC Energy Corporation (TC Energy), formerly known as TransCanada Corporation.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Partnership's financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Certain prior year amounts have been reclassified to conform to the current year presentation.

(b) Use of Estimates

The preparation of the financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

(c) Cash and Cash Equivalents

The Partnership's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

(d) Accounting for Regulated Operations

The Partnership's natural gas pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board Accounting Standards Codification (ASC) 980, *Regulated Operations*, provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. The Partnership evaluates the continued applicability of regulatory accounting, considering such factors as regulatory charges, the impact of competition, and the ability to recover regulatory assets as set forth in ASC 980. Accordingly, certain assets and liabilities that result from the regulated ratemaking process are reflected on the balance sheets as regulatory assets and regulatory liabilities. At December 31, 2019 and 2018, the Partnership does not have any regulatory assets. The following table presents the Partnership's regulatory liabilities at December 31, 2019 and 2018:

	December 31, 2019	December 31, 2018	Remaining recovery/ settlement period (Years)
	(In thousands)		
Negative salvage	**$5,948**	3,664	(a)
Volumetric fuel tracker	**686**	2,389	(b)
	6,634	6,053	
Less: Current portion included in Other	**686**	2,389	
	$5,948	3,664	

(a) Negative salvage accrued for estimated net costs of removal of transmission plant has a settlement period related to the estimated life of the assets (refer to Note 2(h)).

(b) Volumetric fuel tracker assets or liabilities are settled with in-kind exchanges with customers continually.

(e) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest, except for those receivables subject to late charges. The Partnership maintains an allowance for doubtful accounts for estimated losses on accounts receivable, if it is determined the Partnership will not collect all or part of the outstanding receivable balance. The Partnership regularly reviews its allowance for doubtful accounts and establishes or adjusts the allowance as necessary using the specific-identification method. Account balances are charged to the allowance after all means of collection have been exhausted and the potential for recovery is no longer considered probable. There were no accounts charged to the allowance in 2019 and 2018.

(f) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in-kind, subject to the terms of the Partnership's tariff.

Imbalances due from others are reported on the balance sheets as trade accounts receivable or accounts receivable from related parties. Imbalances owed to others are reported on the balance sheets as trade accounts payable or accounts payable to related parties. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(g) Material and Supplies

The Partnership's inventories primarily consist of materials and supplies and are carried at lower of weighted average cost and net realizable value.

(h) Property, Plant, and Equipment

Property, plant, and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs are capitalized, such as labor and materials, and indirect costs, such as overhead and interest are also capitalized. The Partnership capitalizes major units of property replacements or improvements and expenses minor items.

The Partnership uses the composite (group) method to depreciate property, plant, and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The depreciation rate is applied to the total cost of the group until its net book value equals its salvage value. All asset groups are depreciated using the depreciation rates approved by FERC in the Partnership's last rate proceeding. A substantial portion of the Partnership's principal operating assets are being depreciated at an annual rate of 1.27%. The remaining assets are depreciated at annual rates ranging from 2.33% to 10.00%. Using these rates, the remaining depreciable life of these assets ranges from 5 to 47 years.

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as "negative salvage") and recognizes regulatory liabilities in this respect in the balance sheet. Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by FASB ASC 410, *Accounting for Asset Retirement Obligations*. When property, plant, and equipment are retired, the Partnership charges accumulated depreciation and amortization for the original cost of the assets in addition to the cost to remove, sell, or dispose of the assets, less their salvage value. The Partnership does not recognize a gain or loss unless an entire operating unit is sold or retired. The Partnership includes gains or losses on dispositions of operating units in income.

The Partnership capitalizes a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC). AFUDC is recorded based on the Partnership's average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheets.

(i) Long-Lived Assets

Long-lived assets, such as property, plant, and equipment, and purchased intangible assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, the Partnership first compares undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values, and third-party independent appraisals, as considered necessary.

(j) Revenue Recognition

The Partnership's revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas. These 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 utilizes the practical expedient of recognizing revenue as invoiced. Revenues are invoiced and paid monthly. 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.

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. As of December 31, 2019 and 2018, there are no refund provisions reflected in these financial statements.

(k) Accounting for Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. ASC 410-20 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. ASC 410-20 also requires the Partnership to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is to be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

The fair value of a liability for an asset retirement obligation is recorded during the period in which the liability is incurred and if a reasonable estimate of fair value can be made. The Partnership has determined that asset retirement obligations exist for certain of its transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system life is not determinable with the degree of accuracy necessary to establish a liability for the obligations.

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system and intends to do so long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2019 and 2018. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(l) Income Taxes

Income taxes are the responsibility of the partners and are not reflected in these financial statements.

(m) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective-interest rate method over the term of the related debt.

The Partnership amortizes premiums and discounts incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount. In addition, amortization of debt issuance costs, premiums, and discounts are reported as part of interest expense.

(n) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable and certain accrued expenses, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments, fair value is estimated based upon market values (if applicable) or on the current interest rates available to the Partnership for debt with similar terms and remaining maturities. Judgment is required in developing these estimates.

(3) ACCOUNTING CHANGES

Effective January 1, 2019

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee 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 consolidated balance sheet for all leases with a term longer than twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statements of income. The new guidance does not make extensive changes to previous lessor accounting.

Under the new guidance, the Partnership determines if an arrangement is a lease at inception. Operating leases are recognized as ROU assets and included in Property, plant and equipment while corresponding liabilities are included in "Other current liabilities", and "Other long-term liabilities" on the balance sheets.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at commencement date. If the Partnership's leases do not have an implicate rate, the present value of future minimum payments, if any, will be determined using a rate that approximates the Partnership's borrowing cost. Operating lease expense is recognized on a straight-line basis over the lease term and included in "Operation and maintenance expenses" in the Statements of Income.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption and recognize a cumulative-effect adjustment to the opening balance of equity in the period of adoption. This transition option allowed the Partnership to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

The Partnership elected available practical expedients and exemptions upon adoption which allowed the Partnership:

- not to reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and our accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- to not separate lease and non-lease components for all leases for which the Partnership is the lessee
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

In the application of the new guidance, assumptions and judgements are used to determine the following:

- whether a contract contains a lease and the duration of the lease term including exercising lease renewal options. The lease term for all of the Partnership's leases includes the non-cancellable period of the lease plus any additional periods covered by either the Partnership's option to extend (or not to terminate) the lease that the Partnership is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor; and
- the discount rate for the lease.

Upon review of our existing arrangements, no contracts qualified as a lease therefore the standard did not impact the Partnership's previously reported results and did not have material impact on its financial statements at the date of adoption.

Fair Value Measurement

In August 2018, the FASB issued new guidance that amends 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 of certain or all requirements is permitted. The Partnership elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material effect on the Partnership's financial statements.

Future Accounting Changes

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. The adoption of this new guidance will not have a material impact on the Partnership's financial statements.

(4) COMMITMENTS AND CONTINGENCIES

(a) Contingencies

The Partnership is subject to various legal proceedings in the ordinary course of business. The accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with ASC 450, Contingencies. The Partnership bases these estimates on currently available facts and the estimates of the ultimate outcomes or resolution. Actual results may vary from estimates resulting in an impact, positive or negative, on results of operations and cash flows. 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.

(b) Legal Proceedings

The Partnership is not a party in any material legal proceedings as of December 31, 2019.

(c) Environmental Matters

The Partnership is not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

(d) Rights-of-Way Agreements with Native American Tribes

The majority of the land on which the Partnership operates is leased pursuant to easements, rights-of-way and other land use rights from individual landowners, Native American tribes, governmental authorities and other third parties, the majority of which are perpetual and obtained through agreement with land owners or legal process, if necessary. Certain rights, however, are subject to renewal and, with respect to tribal land held in trust by the Bureau of Indian Affairs (BIA), approval by the applicable tribal governing authorities and the BIA.

During the second quarter of 2018, rights-of-way expired for approximately 7.6 miles of the Partnership's pipeline system on tribal land located within the Fond du Lac Reservation and Leech Lake Reservation in Minnesota and the Bad River Reservation in Wisconsin. As a result, beginning the second quarter of 2018, the Partnership started accruing the estimated costs and associated liability related to these pending agreements.

The Partnership cannot predict the outcome of these negotiations. If the Partnership is unable to obtain new easements or rights-of-way across all or a portion of the tribal lands at reasonable rates, or at all, the Partnership may be required to acquire the necessary rights at significant cost or remove and re-route portions of the pipeline at significant capital costs and disruption to operations that could have a material adverse effect on its financial condition, results of operations and cash flows.

(e) Regulatory Matters

2018 FERC Actions

The Partnership has completed the regulatory filing that was required by FERC (see details below) to address the issues contemplated by Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act (2017 Tax Act)and certain FERC actions that began in March of 2018, namely FERC's Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that 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 quantified the rate impact of the 2017 Tax Act on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by Master Limited Partnerships (MLP), such as the Partnership:

Pipelines filing FERC Form No. 501-G had 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 guaranteed a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G showed 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 believed that using the limited Section 4 option would not result in just and reasonable rates. If the pipeline committed to file by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it did not believe the pipeline's rates must change; or

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

2017 Rate Case and subsequent limited section 4 rate reduction

The Partnership operates under a settlement approved by FERC effective January 1, 2018 (2017 Settlement). The 2017 Settlement did not contain a moratorium and eliminated its revenue sharing mechanism with customers. The Partnership is required to file new rates effective October 1, 2022. Additionally, the Partnership's annual depreciation rates remain materially unchanged but for regulatory purposes, the Partnership is required to reflect a negative salvage at an annual rate of 0.15% of transmission plant.

Beginning October 1, 2017, the Partnership was still charging customers rates in effect prior to the 2017 Settlement but was only recognizing revenue up to the amount of the new rates in the 2017 Settlement. The difference between these two amounts was recognized as a provision for rate refund on the balance sheet and refunded in the first quarter of 2018.

Effective February 1, 2019, FERC approved an additional 2 percent rate reduction to the 2017 Settlement approved rates, and eliminated its tax allowance and ADIT liability from rate base pursuant to the Partnership's filing of Form 501-G electing a limited Section 4 (Option 1). The Partnership's 501-G docket remains open.

(f) Other Commercial Commitments

The Partnership has easements or rights-of-way arrangements from landowners permitting the use of land for the construction and operation of the Partnership's pipeline system. The Partnership's future minimum payments on its rights-of-way commitments are as follows:

Year Ending (In thousands)	**Rights-of-Way**
2020	101
2021	61
2022	63
2023	65
2024	67
Thereafter	1,095
	$1,452

(5) LONG-TERM DEBT

The Partnership's outstanding long-term debt consisted of the following at December 31:

(In thousands)	**2019**	**2018**
9.09% series Senior Notes due 2016 to 2021	**$20,000**	30,000
6.95% series Senior Notes due 2019 to 2028	**99,000**	110,000
8.08% series Senior Notes due 2021 to 2030	**100,000**	100,000
	219,000	240,000
Less: Unamortized debt issuance costs	**183**	218
Less: current maturities	**21,000**	21,000
Total long-term debt, net	**$197,817**	218,782

The Partnership's long-term debt repayments consisted of the following at December 31, 2019 (in thousands of dollars):

Year Ending	
2020	21,000
2021	31,000
2022	21,000
2023	21,000
2024	21,000
Thereafter	104,000
	$219,000

The Partnership is required to comply with certain financial, operational, and legal covenants. Under the most restrictive covenants in the Senior Notes Agreements, approximately $118.0 million of partners' capital was restricted as to distributions as of December 31, 2019. As of December 31, 2019, Partnership was in compliance with all of its financial covenants.

(6) FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurement*, fair value measurements are characterized in one of three levels based upon the input 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 the Partnership has 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, accrued interest, all current receivable and payable accounts, except for natural gas imbalances are classified as Level 1 in fair value hierarchy. Accordingly, the carrying values approximate their fair values because of the short maturity or duration of these instruments. The Partnership's natural gas imbalances, which are reported as part of accounts receivable, accounts payable and related party accounts, are classified as a Level 2 in the "Fair Value Hierarchy," as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance. Natural gas imbalances represent the difference between the amount of natural gas delivered to or received from a pipeline system and the amount of natural gas scheduled to be delivered or received at current market prices. The Partnership values these imbalances by applying the difference between the measured quantities of natural gas delivered to or received from our shippers and operators to the current Emerson Viking GL index price. For the year ended December 31, 2019, the total estimated fair value of our natural gas imbalance was a net payable of approximately $1.2 million. (2018 — net receivable of $1.8 million). For the year ended December 31, 2019, the total estimated fair value of our related party natural gas imbalance was a net receivable of approximately $1.3 million. (2018 — net receivable of $0.4 million).

For the year ended December 31, 2019, the fair value of the Partnership's long term debt was $287 million (2018 — $288 million) The fair value was estimated based on quoted market prices for the same or similar debt instruments with similar terms and remaining maturities, which is classified as Level 2 in the "Fair Value Hierarchy", where the fair value is determined by using valuation techniques that refer to observable market data.

(7) TRANSACTIONS WITH RELATED PARTIES

(a) Cash Management Program

The Partnership participates in TC Energy's cash management program, which matches short-term cash surpluses and needs of participating related parties, thus minimizing total borrowings from outside sources. Monies advanced under the program are considered loans, accruing interest and repayable on demand. The Partnership receives interest on monies advanced to TC Energy at the rate of interest earned by TC Energy on its short-term cash investments. The Partnership pays interest on monies advanced from TC Energy based on TC Energy's short-term borrowing costs. For the years ended December 31, 2019, 2018 and 2017, the net interest income on this arrangement is immaterial. At December 31, 2019 and 2018, the Partnership had a demand loan receivable from TC Energy of $34.3 million and $35.9 million, respectively.

(b) Related Party Revenues and Expenses

The Partnership earns significant transportation revenues from TC Energy and its related parties under contracts, which provide for negotiated, discounted and maximum recourse rates. The contracts are on the same terms as would be available to other shippers and the majority of the Partnership's related party revenue is derived from both short-haul and long-haul transportation services.

Pursuant to the Partnership's Operating Agreement, day-to-day operation of partnership activities is the responsibility of the Company. The Partnership is charged by the Company and related parties for services such as legal, tax, treasury, human resources, other administrative functions, and for other costs incurred on its behalf. These include, but are not limited to, employee benefit costs and property and liability insurance costs. These costs are based on direct assignment to the extent practicable, or by using allocation methods that are reasonable reflections of the utilization of services provided to or for the benefits received by the Partnership.

The following table shows revenues and charges from the Partnership's related parties for the years ended December 31:

(In thousands)	2019	2018	2017
Transportation revenues from related parties[(a)]	**$176,021**	178,366	130,165
Cost recovery from related parties[(b)]	**740**	1,332	1,556
Costs charged from related parties	**47,421**	43,737	35,381

(a) Transportation revenues from related parties represent the amount recognized by the Partnership before any allowance on revenue sharing and provision for rate refund, which represent 73%, 73% and 57%, of the Partnership's total revenues for the year ended December 31, 2019, 2018 and 2017, respectively.

(b) Cost recovery from related parties represents the Partnership's recovery of a portion of the costs of the facility it owns by charging its related parties for use of office space in Troy, Michigan. The building in Troy, Michigan was sold in August 2019 for a gain of approximately $780 thousand.

The Partnership has a long-term transportation agreement with TC Energy's Canadian Mainline (Canadian Mainline) that commenced on November 1, 2017 for a ten-year period that allows TransCanada to transport up to 0.711 billion of cubic feet of natural gas per day. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from TC Energy's long-term fixed price service on its Canadian Mainline that was launched in 2017. During the year ended December 31, 2019 the Partnership recognized transportation revenue of $75.8 million related to this contract (2018 — $75.8 million, 2017 — $13 million)

During the year-ended December 31, 2019, the Partnership's remaining $99.5 million of transportation revenues from related parties was associated with its other transportation contracts with Canadian Mainline amounting to $48.1 million and another related party, TC Energy's ANR Pipeline Company (ANR) amounting to $51.4 million.

In 2018, the Partnership executed a long-term transportation capacity contracts with its related party, ANR Pipeline Company. The contracts are for a term of 15 years from November 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, 2020 for any reason and (ii) any time before April 2021, if TC Energy is not able to secure the required regulatory approval related to anticipated expansion projects.

(8) REVENUES

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers 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".

(a) Disaggregation of Revenues

For the year ended December 31, 2019 and 2018, effectively all the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2 — Significant Accounting Policies.

(b) Revenues Subject to Refund

Also noted under Note 2 — Significant Accounting Policies, a portion of our revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. The Partnership uses its best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue the Partnership recognized.

During the year ended December 31, 2017, the Partnership operated under a FERC approved 2013 rate settlement that included a revenue sharing mechanism that requires the Partnership to share with its shippers 50% of any qualifying revenues earned during the year that result in a return on equity (ROE) above 13.25%. Qualifying revenues above a 20% ROE are returned to shippers at 100%. The Partnership establishes a provision for this revenue sharing as an offset against revenue in the income statement and recognizes an estimated refund liability classified as provision for revenue sharing refund in the balance sheet. Accordingly, the revenues presented in the statement of income for the years ended December 31, 2017 were net of $39.6 million estimated revenue sharing provision, settled in 2018. As discussed under Note 4(b), beginning in 2018, the revenue sharing mechanism was eliminated as part of the 2017 Settlement.

(c) Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under Accounts receivable in the balance sheet. Additionally, our accounts receivable represents the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

(d) Right to invoice practical expedient

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 capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied.

(9) DISTRIBUTIONS

The Partnership's distribution policy generally results in a quarterly cash distribution equal to 100 percent of distributable cash flow based upon earnings before income taxes, depreciation, AFUDC less capital expenditures and debt repayments not funded with cash calls to its partners. The resulting distribution amount and timing are subject to Management Committee modification and approval after considering business risks as well as ensuring minimum cash balances, equity balances, and ratios are maintained.

On January 10, 2020, the Management Committee of the Partnership declared a cash distribution in the amount of $34.4 million to the partners. The distribution was paid on January 31, 2020.

(10) SUBSEQUENT EVENTS

Subsequent events have been assessed through February 14, 2020, which is the date the financial statements were issued, and the Partnership concluded there were no events or transactions during this period that would require recognition or disclosure in the financial statements other than those already reflected.

Independent Auditors' Report

TO THE PARTNERS OF IROQUOIS GAS TRANSMISSION SYSTEM, L.P.:

We have audited the accompanying consolidated financial statements of Iroquois Gas Transmission System, L.P., and its subsidiaries (the Partnership), which comprise the consolidated balance sheets as of December 31, 2019 and 2018, and the related consolidated statements of comprehensive income, changes in partners' equity and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Iroquois Gas Transmission System, L.P., and its subsidiaries as of December 31, 2019 and 2018, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2019, in accordance with accounting principles generally accepted in the United States of America.

Changes in Accounting Principle

As discussed in Note 2, during the year ended December 31, 2019, Iroquois Gas Transmission System, L.P. and its subsidiaries adopted Accounting Standards Update No. 2016-02, *Leases (Topic 842)* and Accounting Standards Update No. 2018-11, *Targeted Improvements to ASC 842, Leases*. Our opinion is not modified with respect to this matter.

Blum, Shapiro & Company, P.C.

Blum, Shapiro & Company, P.C.
West Hartford, Connecticut
February 19, 2020

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.

Consolidated statements of comprehensive income

For the years ended December 31 (thousands of dollars)	**2019**	**2018**	**2017**
Operating Revenues *(Notes 7, 8, and 9)*	**$179,615**	$193,780	$193,460
Operating Expenses:			
Operation and maintenance *(Note 13)*	**28,872**	29,158	27,900
Depreciation and amortization *(Note 3)*	**29,486**	29,177	28,849
Taxes other than income taxes	**28,297**	27,628	27,348
Total Operating Expenses	**86,655**	85,963	84,097
Operating Income	**92,960**	107,817	109,363
Other Income / (Expenses):			
Interest income	**859**	911	332
Allowance for equity funds used during construction	**2,244**	2,098	2,210
Other, net *(Note 13)*	**1,688**	1,216	(714)
	4,791	4,225	1,828
Interest Expense:			
Interest expense	**16,701**	19,203	19,522
Allowance for borrowed funds used during construction	**(988)**	(1,009)	(924)
	15,713	18,194	18,598
Net Income	**$82,038**	$93,848	$92,593
Other comprehensive income/(loss) — effects of retirement benefit plans *(Note 10)*	**2,308**	(2,521)	1,830
Comprehensive Income	**$84,346**	$91,327	$94,423

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.

Consolidated balance sheets

At December 31 (thousands of dollars)	2019	2018
ASSETS		
Current Assets:		
Cash and temporary cash investments	**$43,351**	$80,393
Accounts receivable — trade	**20,239**	17,106
Prepaid property taxes	**11,100**	10,722
Other current assets	**4,422**	4,164
Total Current Assets	**$79,112**	$112,385
Natural Gas Transmission Plant:		
Natural gas plant in service	**1,310,465**	1,296,895
Construction work in progress	**59,003**	55,495
	1,369,468	1,352,390
Accumulated depreciation and amortization	**(799,876)**	(771,344)
Net Natural Gas Transmission Plant *(Note 3)*	**569,592**	581,046
Other Assets and Deferred Charges:		
Other assets and deferred charges	**15,914**	6,405
Total Other Assets and Deferred Charges	**15,914**	6,405
Total Assets	**$664,618**	$699,836
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities:		
Accounts payable	**$3,696**	$3,483
Distribution payable to partner *(Note 2)*	**13,616**	—
Accrued interest	**1,745**	1,953
Current portion of long-term debt *(Note 4)*	**3,000**	146,000
Customer deposits	**9,064**	11,091
Other current liabilities	**6,206**	2,742
Total Current Liabilities	**$37,327**	$165,269
Long-Term Debt, net *(Note 4)*	**313,617**	178,069
Other Non-Current Liabilities:		
Other non-current liabilities	**19,824**	13,607
Other Non-Current Liabilities	**19,824**	13,607
Commitments and Contingencies *(Note 7)*		
Total Liabilities	**370,768**	356,945
Partners' Equity	**293,850**	342,891
Total Liabilities and Partners' Equity	**$664,618**	$699,836

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.

Consolidated statements of cash flows

For the years ended December 31 (thousands of dollars)	**2019**	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	**$82,038**	$93,848	$92,593
Adjusted for the following:			
Depreciation and amortization	**29,486**	29,177	28,849
Allowance for equity funds used during construction	**(2,244)**	(2,098)	(2,210)
Other assets and deferred charges	**(1,815)**	1,317	(1,490)
Other non-current liabilities	**1,932**	1,331	4,814
Amortization of debt issuance costs	**450**	231	390
Changes in working capital:			
Accounts receivable	**(3,133)**	3,614	(1,884)
Prepaid property taxes	**(378)**	(272)	20
Other current assets	**(340)**	(168)	(259)
Accounts payable	**1,301**	381	(1,367)
Customer deposits	**(2,027)**	407	151
Accrued interest	**(208)**	(40)	(60)
Other current liabilities	**2,445**	556	(231)
Net Cash Provided by Operating Activities	**107,507**	128,284	119,316
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	**(16,876)**	(15,238)	(14,067)
Net Cash Used For Investing Activities	**(16,876)**	(15,238)	(14,067)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Partner contributions	**7,000**	—	—
Partner distributions	**(126,771)**	(114,248)	(100,476)
Long-term debt borrowing	**140,000**	—	—
Repayments of long-term debt	**(146,000)**	(4,000)	(5,500)
Payments for debt issuance costs	**(1,902)**	—	—
Net Cash Used For Financing Activities	**(127,673)**	(118,248)	(105,976)
Net Decrease in Cash and Temporary Cash Investments	**(37,042)**	(5,202)	(727)
Cash and Temporary Cash Investments at Beginning of Year	**80,393**	85,595	86,322
Cash and Temporary Cash Investments at End of Year	**$43,351**	$80,393	$85,595
Supplemental Disclosure of Cash Flow Information:			
Cash paid for interest	**$16,596**	$18,874	$19,192
Accruals for capital expenditures	**$1,073**	$2,161	$314

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.

Consolidated statements of changes in partners' equity

(thousands of dollars)	Net Income	Distributions to Partners	Contributions from Partners	Accumulated Other Comprehensive (Loss)/Income	Total Partners' Equity
December 31, 2016					
Balance	$1,502,244	$(1,406,544)	$279,381	$(3,216)	$371,865
Net Income	92,593	—	—	—	92,593
Equity Distributions to Partners *(Note 1)*	—	(100,476)	—	—	(100,476)
Other Comprehensive Loss *(Note 10)*	—	—	—	1,830	1,830
December 31, 2017					
Balance	$1,594,837	$(1,507,020)	$279,381	$(1,386)	$365,812
Net Income	93,848	—	—	—	93,848
Equity Distributions to Partners *(Note 1)*	—	(114,248)	—	—	(114,248)
Other Comprehensive Income *(Note 10)*	—	—	—	(2,521)	(2,521)
December 31, 2018					
Balance	$1,688,685	$(1,621,268)	$279,381	$(3,907)	$342,891
Net Income	82,038	—	—	—	82,038
Equity Distributions to Partners *(Note 1)*	—	(140,387)	—	—	(140,387)
Equity Contributions from Partners *(Note 1)*	—	—	7,000	—	7,000
Other Comprehensive Income *(Note 10)*	—	—	—	2,308	2,308
December 31, 2019					
Balance	**$1,770,723**	**$(1,761,655)**	**$286,381**	**$(1,599)**	**$293,850**

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.

Notes to consolidated financial statements

NOTE 1 DESCRIPTION OF PARTNERSHIP:

Iroquois Gas Transmission System, L.P., (the Partnership or Iroquois) is a Delaware limited partnership that owns and operates a natural gas transmission pipeline from the Canada-United States border near Waddington, NY, to South Commack, Long Island, NY and Hunt's Point, Bronx, New York. In accordance with the limited partnership agreement, the Partnership shall continue in existence until October 31, 2089, and from year to year thereafter, until the partners elect to dissolve the Partnership and terminate the limited partnership agreement.

On June 1, 2017, TCPL Northeast Ltd. and TransCanada Iroquois Ltd. sold their 21.00% and 28.34% interest in the Partnership, respectively, to their affiliate, TC PipeLines Intermediate Limited Partnership (TCILP) for a total 49.34% interest in the Partnership. TC Energy's Master Limited Partnership, TC PipeLines, LP (TCP) is TCILP's parent.

On January 28, 2019, Dominion Energy Midstream Partners became an indirect, wholly owned subsidiary of Dominion Energy.

On October 31, 2019, TCILP assigned 100.0% of its interest in the Partnership to its parent TCP.

As of December 31, 2019, the partners consist of TCP (TC Energy), (49.34%), Iroquois GP Holding Company, LLC (Dominion Energy) (25.93%), Dominion Iroquois, Inc. (Dominion Energy) (24.07%), and TransCanada Iroquois Ltd. (TC Energy) (0.66%). TransCanada Iroquois Ltd. and TCP's ultimate parent is TC Energy Corporation (TC Energy), formerly known as TransCanada Corporation. Iroquois Pipeline Operating Company, a wholly owned subsidiary, is the administrative operator of the pipeline. IGTS, Inc. of Connecticut is an additional wholly owned subsidiary formed to hold title to certain Connecticut property interests.

Income and expenses are allocated to the partners and credited to their respective equity accounts in accordance with the partnership agreements and their respective percentage interests. Distributions to partners are made concurrently to all partners in proportion to their respective partnership interests.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Basis of Presentation

The consolidated financial statements of the Partnership are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The Partnership's natural gas pipeline is subject to regulation by the Federal Energy Regulatory Commission (FERC). Generally accepted accounting principles for regulated entities allow the Partnership to give accounting recognition to the actions of regulatory authorities. In accordance with GAAP, the Partnership has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or an obligation relieved in the future through the rate-making process.

Principles of Consolidation

The consolidated financial statements include the accounts of the Partnership, Iroquois Pipeline Operating Company and IGTS, Inc. of Connecticut. Intercompany transactions have been eliminated in consolidation.

Cash and Temporary Cash Investments

The Partnership considers all highly liquid temporary cash investments purchased with an original maturity date of three months or less to be cash equivalents.

Natural Gas Plant in Service

Natural gas plant in service is carried at original cost. The majority of the natural gas plant in service is categorized as natural gas transmission plant. Effective September 1, 2016, as a result of the rate case (refer to Note 7) natural gas transmission plant assets are depreciated at a range of 1.7% to 2.95%. The rate for general plant assets which includes primarily vehicles, leasehold improvements and computer equipment are depreciated at a range of 1.9% to 12.0%. The rates for intangible plant assets are depreciated at a range of 0.35% to 2.0%.

Construction Work in Progress/Commitments

At December 31, 2019 and December 31, 2018 construction work in progress primarily included preliminary construction costs relating to the Wright Interconnect (WIP) Project and Enhancement by Compression (ExC) Project. The Partnership also has commitments of approximately $2.5 million relating to the WIP Project at December 31, 2019 (Refer to Note 2 — Subsequent Events).

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) represents the cost of funds used to finance natural gas transmission plant under construction. The AFUDC rate includes a component for borrowed funds as well as equity. The AFUDC is capitalized as an element of natural gas plant in service.

Revenue Recognition

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 utilizes the practical expedient of recognizing revenue as invoiced. The Partnership's pipeline system does 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.

The Partnership's pipeline system is 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. As of December 31, 2019, and 2018, there are no refund provisions reflected in these financial statements. Refer to Note 9 for detailed disclosures regarding the Partnership's revenues.

Income Taxes

Income taxes are the responsibility of the partners and are not reflected in these financial statements.

CT Pass-Through Entity Tax

On May 31, 2018, Connecticut passed legislation establishing a new pass-through entity tax. The Partnership elected to utilize the alternative tax base which excludes any income attributable to publicly traded partnerships or corporations and therefore does not owe any tax.

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The key estimates include determining the economic useful lives of the Partnership's assets, the fair values used to determine possible asset impairment charges, exposures under contractual indemnifications, calculations of pension expense and various other recorded or disclosed amounts. The Partnership believes that its estimates for these items are reasonable but cannot assure that actual amounts will not vary from estimated amounts.

Asset Retirement Obligations

The Partnership accounts for asset retirement obligations in accordance with GAAP, which requires entities to record the fair value of a liability for an asset retirement obligation during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. The Partnership has determined that asset retirement obligations exist for certain of its transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system life is not determinable with the degree of accuracy necessary to establish a liability for the obligations.

Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the straight-line method over the term of the related debt.

Debt issuance costs are presented in the consolidated balance sheet as a direct deduction from the carrying amount of debt liabilities. In addition, amortization of debt issuance costs are reported as part of interest expense. Debt issuance costs in prior years were immaterial, but the amounts have been reclassified to conform to the current year presentation.

Accounting Pronouncements

Changes Effective January 1, 2019

Leases

In February 2016, the Financial Accounting Standards Board (FASB) issued new guidance Accounting Standards Update (ASU) ASU 2016-02, Leases (Topic 842). The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee, throughout the period of use, 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 consolidated balance sheet for all leases with a term longer than twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statements of comprehensive income. The new guidance does not make extensive changes to previous lessor accounting.

Under the new guidance, the Partnership determines if an arrangement is a lease at inception. Operating leases are recognized as ROU assets and included in Other assets and deferred charges while corresponding liabilities are included in Other current liabilities, and Other non-current liabilities on the consolidated balance sheets.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at commencement date. If the Partnership's leases do not have an implied rate, the present value of future minimum payments, if any, will be determined using a rate that approximates the Partnership's incremental borrowing cost. Operating lease expense is recognized on a straight-line basis over the lease term and is included in Operation and maintenance expenses in the consolidated statements of comprehensive income.

The new guidance is effective January 1, 2021, with early adoption permitted. The Partnership early adopted the new standard ASU 2018-11, Leases-Target Improvements, on January 1, 2019. Under ASU 2018-11, the Partnership utilized the optional transition relief which allows entities to report comparative periods presented in the period of adoption under Accounting Standard Codification (ASC) ASC Topic 840. Consequently, financial information was not recast and the Partnership will recognize the effects of applying the guidance required under the new standard as of January 1, 2019.

The Partnership elected available practical expedients and exemptions upon adoption which permits entities (1) not to reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard; (2) to carry forward the historical lease classification and accounting treatment for land easement on existing agreements; (3) to not recognize ROU assets or liabilities for leases that qualify for the short-term lease recognition exemption; (4) to not separate lease and non-lease components for all leases for which the Partnership is the lessee; and (5) to use hindsight in determining the lease term and assessing ROU assets for impairment.

In the application of the new guidance, assumptions and judgements are used to determine (1) whether a contract contains a lease and the duration of the lease term including exercising lease renewal options. The lease term for all of the Partnership's leases includes the non-cancellable period of the lease plus any additional periods covered by either the Partnership's option to extend (or not to terminate) the lease that the Partnership is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor; and (2) the discount rate for the lease. Refer to Note 11 for further information regarding lease disclosures.

Reclassification

Certain prior year amounts have been reclassified to conform with current year classifications.

Subsequent Events

Wright Interconnect Project (WIP)

Subsequent to year end, Iroquois has received notice of termination of the Precedent Agreement (PA) between Iroquois and Constitution effective February 10, 2020. That PA sets forth, among other things, Iroquois' obligation to construct the WIP project facilities. The parties are working to finalize closure of the project pursuant to the terms of the PA.

As of December 31, 2019, Iroquois had incurred approximately $52.2 million of expenditures related to primarily engineering and procurement of materials and had made approximately $2.5 million in additional project related commitments. Due to contractual agreements in place, including a guarantee from Williams Partners, L.P., a 41% owner of Constitution, Iroquois will be exercising its contractual right to seek reimbursement for the total of these expenditures. While total expenditures might exceed the guarantee, the Iroquois believes it is not at material financial risk for recovery of these expenditures (refer to Note 7 — Wright Interconnect Project).

Enhancement by Compression Project (ExC)

During 2019 the Partnership entered into precedent agreements with Con Edison and KeySpan Gas East Corporation d/b/a National Grid to develop and permit incremental pipeline delivery capacity to transport additional volumes of natural gas along Iroquois' system. The project optimizes the Iroquois system to meet current and future gas supply needs of utility customers while minimizing environmental impact through compressor enhancements at existing compressor stations along the pipeline. The project's total capacity is approximately 125,000 Dth/day and it is 100% underpinned by 20-year term contracts. On February 3, 2020, Iroquois filed for FERC approval of the project. The new facilities are scheduled to be in service by November 2023 with an estimated cost of $250.0 million.

Distributions

On January 6, 2020, the Partnership paid $13.6 million to TCP, relating to the distribution declared on December 30, 2019.

In February 2020, the Partnership approved a distribution in the amount of $26.5 million. The distribution, which will be paid on March 30, 2020, includes its eleventh and final surplus cash distribution in the amount of $5.2 million as discussed in Note 7 — Distributions.

The Partnership has evaluated all subsequent events through February 19, 2020, which is the date on which the financial statements were available to be issued.

NOTE 3 NATURAL GAS TRANSMISSION PLANT:

	Balances at December 31,	
(thousands of dollars)	**2019**	**2018**
Classification		
Transmission Plant	**$1,284,248**	$1,273,929
General Plant	**26,217**	22,966
	1,310,465	1,296,895
Less Accumulated Depreciation	**(799,876)**	(771,344)
Construction Work in Progress	**59,003**	55,495
Net Natural Gas Transmission Plant	**$569,592**	$581,046

Depreciation and amortization expense was $29.5 million in 2019, $29.2 million in 2018 and $28.8 million in 2017.

NOTE 4 LONG TERM DEBT:

On May 9, 2019, the Partnership refinanced its 6.63% $140.0 million and 4.48% $150.0 million senior notes due 2019 and 2020, respectively by issuing a new 15-year 4.12% $140.0 million, non-amortizing senior notes due 2034, and new 10-year 4.07% $150.0 million, non-amortizing senior notes due 2030*.

Detailed information on long-term debt is as follows (thousands of dollars):

At December 31	2019	2018
Senior Notes — 6.10% due August 2027	**29,000**	35,000
Senior Notes — 6.63% due May 2019	**—**	140,000
Senior Notes — 4.84% due April 2020*	**150,000**	150,000
Senior Notes — 4.12% due May 2034	**140,000**	—
Total	**319,000**	325,000
Less Current Maturities of Long-Term Debt	**3,000**	146,000
Long-Term portion	**316,000**	179,000
Less unamortized debt issuance costs	**2,383**	931
Long-term debt, net	**313,617**	178,069

* The refinancing agreement for the 4.07% $150.0 million senior notes, which is a firm commitment, has a delay draw feature where the Partnership will not be paying any interest on the new 4.07% $150.0 million senior notes until the funds are drawn to repay the existing 4.84% $150.0 million senior notes in 2020. As a result, the $150.0 million due 2020 is classified as long term debt. The Partnership will continue to pay the current interest rate 4.84% until April 27, 2020 when the interest rate of 4.07% becomes effective.

The combined schedule of repayments at December 31, 2019 is as follows (thousands of dollars):

Year	Scheduled Repayment
2020	$3,000
2021	$4,500
2022	$3,000
2023	$4,500
2024	$4,000
Thereafter	$300,000

The above loans and facilities require the Partnership to maintain compliance with certain restrictive covenants relating to, among other things, certain ratios of indebtedness to total capitalization must be below 75 percent, and debt service coverage ratio must be at least 1.25 times for the four preceding quarters, as defined in the credit agreements and bond indentures. The Partnership is in compliance with these covenants as of and for the years ended December 31, 2019, December 31, 2018 and December 31, 2017.

On June 13, 2019, the $10.0 million revolving credit facility was renewed for 364 days. As of December 31, 2019, there are no amounts outstanding under the revolving credit facility.

NOTE 5 CONCENTRATIONS OF CREDIT RISK:

The Partnership's cash and temporary cash investments and trade accounts receivable represent concentrations of credit risk. Management believes that the credit risk associated with cash and temporary cash investments is mitigated by its practice of limiting its investments primarily to commercial paper rated P-1 or higher by Moody's Investors Services and A-1 or higher by Standard and Poor's, and its cash deposits to large, highly-rated financial institutions. Management also believes that the credit risk associated with trade accounts receivable is mitigated by the restrictive terms of the FERC gas tariff that require customers to pay for service within 20 days after the end of the month of service delivery. Also, the Partnership's FERC-approved tariff provides that, subject to certain exceptions, the Partnership has the right to require that shippers have an investment grade rating or obtain a written shipper guarantee from a third party with an investment grade rating, or provide other financial assurances before service can be provided.

NOTE 6 FAIR VALUE OF FINANCIAL INSTRUMENTS:

The fair value amounts disclosed below have been reported to meet the disclosure requirements of GAAP and are not necessarily indicative of the amounts that the Partnership could realize in a current market exchange.

Under ASC 820, Fair Value Measurement, fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. The three levels of fair value hierarchy are as follows; (1) Level 1 inputs are quoted market process for identical assets on an active market to which an entity has access at the measurement date; (2) Level 2 inputs are inputs from other than quoted market prices that are observable for the asset or liability, either directly or indirectly (i.e. quoted market prices for similar assets or liabilities); (3) 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.

As of December 31, 2019, and December 31, 2018, the carrying amounts of cash and temporary cash investments, accounts receivable, accounts payable and accrued expenses are classified as Level 1 in the fair value hierarchy. Accordingly, the carrying values approximate fair values because of the short maturity or duration of these instruments.

The fair value of long-term debt, which is classified as Level 2 in the fair value hierarchy is estimated by the Partnership's underwriter based on treasury rates and comparable spreads at fiscal year-end. As of December 31, 2019, and December 31, 2018, the carrying amounts and estimated fair values of the Partnership's long-term debt including current maturities were as follows (in thousands of dollars):

Year	Carrying Amount	Fair Value
2019	**$319,000**	**$334,865**
2018	$325,000	$332,372

NOTE 7 COMMITMENTS AND CONTINGENCIES:

Regulatory Proceedings

Mainline and Eastchester Rate Case Settlement

On January 21, 2016, the FERC opened Docket RP 16-301-000 to examine the appropriateness of the recourse rates charged by the Partnership for both its mainline and Eastchester shippers (2016 Rate Case). On April 5, 2016, the Partnership filed an analysis of its existing revenues and costs with the FERC as required by the January 21, 2016 order. Settlement conferences occurred on April 28, 2016, May 18, 2016, June 1, 2016 and June 16, 2016 which culminated in an agreement in principal resolving the 2016 Rate Case issues (Settlement). On August 18, 2016, as agreed to by the Parties, the Settlement was filed with the FERC concurrent with a motion for interim rates to be placed into effect on September 1, 2016. On August 26, 2016, the Chief Administrative Law Judge issued an order approving the interim rates effective September 1, 2016.

On October 20, 2016, the FERC issued an order approving the Settlement reached between the Partnership and the other parties. Pursuant to the Settlement, there will be a rate moratorium wherein no new firm recourse rates can be placed into effect on the Partnership's mainline or Eastchester facilities until September 1, 2020. Following the conclusion of the moratorium, if no rate case is filed or if no new rate settlement is reached, the Partnership must file a Section 4 rate case no later than September 1, 2022. During the period of the moratorium, Iroquois will reduce its 100% load factor interzone rate by approximately $0.075 per dekatherm (approximately $0.02 beginning September 1, 2016, an additional

$0.02 beginning September 1, 2017, and an additional $0.035 beginning September 1, 2018). Also during the moratorium period, Iroquois will reduce its 100% load factor Eastchester rate by approximately $0.24 per dekatherm (approximately $0.18 beginning September 1, 2016, and an additional $0.06 beginning September 1, 2018).

Based on long-term firm service contracts in place on September 1, 2016, the approved settlement has resulted in reductions in long-term firm revenue of $2.5 million in 2016, $6.4 million in 2017, $6.6 million in 2018, and $9.3 million in 2019. The settlement also required a modification to the Partnership's depreciation rates which is described in Natural Gas Plant in service in Note 2.

2018 FERC Actions

During 2018, the Partnership has completed the regulatory filing that was required by FERC (see details below) to address the issues contemplated by Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act (2017 Tax Act) and certain FERC actions that began in March of 2018, namely FERC's Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that established a schedule by which interstate pipelines must have either (i) filed a new uncontested rates settlement or (ii) filed a one-time report, called FERC Form No. 501-G that quantified 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. In addition to filing the one-time report, each pipeline had four options: (1) Each pipeline may simultaneously make a limited section 4 filing to reduce its rates by the percentage reduction in its cost of service shown in its FERC Form No. 501-G; (2) Each pipeline may simultaneously commit to file either a prepackaged uncontested rate settlement or a general NGA section 4 rate case if it believes that using the limited section 4 option will not result in a just and reasonable rate. 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; (3) Alternatively, each pipeline that does not believe it has to change its rates may choose to file a statement explaining why; (4) Finally, a pipeline may file the one-time report without taking any other action. At that point, FERC would consider whether to initiate a section 5 investigation of any pipeline that has not submitted a limited section 4 rate reduction filing or committed to file a general section 4 rate case.

Action taken by the Partnership to address the 2018 FERC Actions

Iroquois filed its FERC Form No. 501-G on December 6, 2018, in Docket No. RP19-445-000. Iroquois' Form No. 501-G filing reflected the elimination of its income tax allowance and ADIT balances in accordance with the 2018 FERC Actions. Iroquois stated that no rate adjustments were appropriate in light of its RP16-301 Settlement moratorium. Shippers and other interested parties filed comments and protests and, following negotiations, Iroquois and interested parties reached a settlement in principle pursuant to which Iroquois would reduce its rates by 6.5 percent in two phases to reflect the reduction in income taxes indicated in its Form No. 501-G filing, but otherwise to leave the RP16-301 Rate Settlement in place. This additional rate reduction will be implemented equally in two step-downs. The first step down is effective March 1, 2019, and the second is effective April 1, 2020. Iroquois filed the settlement with FERC on February 28, 2019 (RP19-445 Settlement). On May 2, 2019, FERC issued an order approving the RP19-445 Settlement

Brookfield, Connecticut Site Clean Up

On June 27, 2003, the Partnership purchased real property in Brookfield, Connecticut upon which it constructed its Brookfield compressor station (Brookfield Site or Site). On November 3, 2004, the Connecticut Department of Energy and Environmental Protection (DEEP) approved the Site's remediation plan and scope of work schedule. After the major clean-up, re-grading, and seeding work at the Brookfield Site was completed (with the exception of buried tires on the property which is discussed below), Iroquois received a Letter of No Audit (LNA) from the DEEP dated November 13, 2014. The LNA states that the DEEP agrees with Iroquois' Licensed Environmental Professional (LEP) that the site is now clean (with the exception of the buried tires on the property) and closes the Environmental Condition Assessment Form (ECAF) for the Brookfield Voluntary Cleanup. For the remaining buried tires on the Brookfield site, Iroquois has entered into the state Stewardship Program. The stewardship program authorization expires in May of 2022 at which time Iroquois will file for an additional 10-year extension. The program requires monitoring of the tire area until 2041 and remediation of any erosion, subsidence, or tires that have worked their way to the surface. It is not anticipated that the ongoing monitoring of this site will have a material adverse effect on the Partnership's financial condition or results of operations.

Wright Interconnect Project

In December of 2012, the Partnership entered into a Precedent Agreement (PA) with Constitution Pipeline Company, LLC (Constitution). The PA requires the Partnership to expand its current compression station located in Wright, New York. The project, which consists of constructing two new compressor units in addition to new metering facilities, and other minor facility modifications, would enable the Partnership to accept up to 650,000 Dth/d of gas from the proposed Constitution pipeline and deliver this gas into either the Partnership's currently existing mainline or into the Tennessee Gas Pipeline. Pursuant to the PA, Constitution and the Partnership will enter into a capacity lease agreement in which Constitution leases the transmission capacity made available by the new compressor units. This lease agreement is for a period of fifteen years with an option for Constitution to extend the lease an additional five years. This project will require FERC and other regulatory approvals. On June 13, 2013, the Partnership and Constitution filed for FERC approval of the project. On December 2, 2014, the Partnership received its 7(c) Certificate Order from FERC granting approval for the project (as well as Constitution's pipeline project), with the approval conditioned on the Partnership obtaining all outstanding permits. The Partnership continues to work with State and Local authorities to obtain all required permits. On November 5, 2018, FERC granted a 2-year extension to complete construction of the project to the Partnership and Constitution.

On April 22, 2016, the New York State Department of Environmental Conservation (DEC) denied Constitution's application for a water quality certification (WQC) under Section 401 of the Clean Water Act. Constitution had applied for the 401 WQC in order to construct its 124 mile pipeline. On May 16, 2016, Constitution filed a petition for review of the denial to the U.S. Court of Appeals for the Second Circuit (Second Circuit), arguing that the DEC's denial was arbitrary and capricious. On August 18, 2017, the Second Circuit issued its opinion denying in part and dismissing in part Constitution's petition. The Second Circuit declined to rule on Constitution's argument that DEC's long-delayed decision on Constitution's Section 401 application triggered a waiver of the DEC's WQC authority under Section 401. The Second Circuit determined that it lacked jurisdiction to address that issue, as jurisdiction lay exclusively with the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) under the Natural Gas Act (NGA). On Constitution's merit arguments, the Second Circuit upheld the DEC's denial of the WQC. Constitution's petition for rehearing of the Second Circuit's decision, and its petition for a writ of certiorari to the U.S. Supreme Court, were both denied. On October 11, 2017, Constitution petitioned the FERC for a declaratory order finding that the DEC failed to act within the statutorily prescribed period of time on Constitution's WQC Application and that such failure to act constitutes a waiver of the DEC's Section 401 authority. FERC issued an Order on January 11, 2018, denying Constitution's petition, and denied rehearing of that order on July 19, 2018.

On September 14, 2018, Constitution filed a petition for review with the D.C. Circuit, requesting review and reversal of FERC's two orders denying Constitution's petition requesting a finding of agency waiver. The D.C. Circuit granted FERC's motion to hold that case in abeyance pending the court's further action in *Hoopa Valley Tribe v. FERC*, D.C. Circuit Case No. 14-1271 (argued October 1, 2018). On January 25, 2019, the D.C. Circuit issued its decision in *Hoopa Valley Tribe v. FERC*, concluding that on the basis of the facts presented there, "the withdrawal-and-resubmission of water quality certification requests does not trigger new statutory periods of review."

On February 25, 2019, FERC filed in the *Constitution Pipeline Company, LLC v. FERC*, D.C. Circuit Case No. 18-1251 proceeding, an unopposed motion for voluntary remand so that it might consider the implications of the *Hoopa Valley* decision on the FERC Orders under review in that case. The D.C. Circuit granted FERC's motion on February 28, 2019. On August 28, 2019, FERC issued its "Order on Voluntary Remand" finding that in light of the *Hoopa Valley* decision, that the DEC had waived its WQC authority with respect to the Constitution Pipeline Project (Constitution Waiver Order). The FERC further denied the DEC's request for a stay of effectiveness of its decision, or alternatively, a stay of any further FERC action to authorize construction of the pipeline project pending further review of the matter or the DEC's issuance of a WQC to Constitution. The DEC and several other parties sought rehearing of this Order. On December 13, 2019, FERC issued its Order denying rehearing and stay of this Order. The DEC filed a petition for review of the above FERC orders on December 30, 2019 with the U.S. Court of Appeals for the Second Circuit. The matter is pending.

The Partnership is required to obtain a Title V Facility Permit (Permit), under the Clean Air Act, for the construction and operations of the WIP facilities. On July 26, 2013, the Partnership filed a Permit application with the DEC, and the DEC subsequently published a Notice of Complete Application (NOCA) on December 24, 2014. The DEC and the Environmental Protection Agency (EPA) regulations implementing the Clean Air Act, state that final action on a Title V Permit must be taken within eighteen months of publishing the NOCA. However, the DEC failed to submit the Permit to the Environmental Protection Agency on or before June 24, 2016, thus violating the eighteen month requirement of the Clean Air Act. The Partnership filed a petition with the DC Circuit on July 13, 2016, pursuant to the NGA, regarding the DEC's failure to timely submit the Permit to the EPA. On October 6, 2016, as amended February 15, 2018, the Partnership and the DEC entered into and filed a Stipulation of Settlement and a Joint Motion to Hold Petition in Abeyance Pending Performance of Stipulation of Settlement. Among other provisions, the Stipulation requires the DEC to submit the Permit to the EPA in the event that Constitution prevails in its litigation regarding the DEC WQC, or is otherwise able to resolve the matter and obtain authority from FERC to commence construction.

By letter dated September 27, 2019, Iroquois requested that the DEC confirm the status of its compliance with the remaining terms of the Stipulation of Settlement filed in this proceeding. Iroquois stated that, under the Stipulation of Settlement, the issuance by FERC of the Constitution Waiver Order was the triggering event for the DEC to release Iroquois' Title V air permit to the EPA to commence a statutory 45-day comment period within 15 business days, assuming DEC had not, during that same time period, sought a stay of such order. Iroquois further stated that, as no stay request had been filed during that period (which expired on September 19, 2019), the Stipulation of Settlement requires the DEC to fulfill its responsibilities and release Iroquois' permit to the EPA. After negotiations, Iroquois and the DEC agreed to a second amendment of the Stipulation of Settlement (Second Amendment) wherein the DEC is required to complete the processing of Iroquois' Title V Permit upon the receipt by Constitution of authority from FERC to commence construction of its pipeline project (referred to as a Notice to Proceed). The DEC's obligation to complete the processing of Iroquois' Title V Permit would be stayed in the event and for so long as FERC or a court with jurisdiction stays Constitution's construction of the pipeline.

As discussed in Note 2 — Subsequent Events, Constitution terminated the Precedent Agreement subsequent to December 31, 2019.

Litigation Proceedings

The Partnership is a party to various legal matters incidental to its business. However, the Partnership believes that the outcome to these proceedings will not have a material adverse effect on the Partnership's financial condition or results of operations.

No liabilities have been recorded by the Partnership in conjunction with any legal matters.

Distributions

The Partnership 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 ration must be below 75 percent and the debt service coverage ratio must be at least 1.25 times for the four preceding quarters. At December 31, 2019, the debt/capitalization ratio was 52.1 percent and the debt service coverage ratio was 5.38 times, therefore, the Partnership was not restricted from making cash distributions.

The Partnership adopted a distribution resolution to distribute surplus cash to its partners of $57.4 million to be paid as part of its quarterly distributions over 11 quarters. Under the terms of the resolution an additional $5.2 million will be paid per quarter, which began with the second quarter 2017 distributions. As of December 31, 2019, the Partnership made ten surplus cash distributions, in accordance with the resolution, totaling $52.2 million.

The Partnership adopted an additional distribution resolution to distribute surplus cash to its partners of $30.0 million to be paid in lump sum. The Partners approved a resolution effective May 13, 2019 to contribute to the Partnership $7.0 million for the purpose of acquiring the necessary regulatory approvals for the new ExC project. Effective August 27, 2019 resolutions were signed to distribute the $30.0 million distribution and the $7.0 contribution which was paid on August 30, 2019.

NOTE 8 MAJOR CUSTOMERS:

For the years ended December 31, 2019, December 31, 2018 and December 31, 2017, two customers provided significant operating revenues totaling $50.3 million, $49.1 million and $46.7 million, respectively.

NOTE 9 REVENUES:

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for 2019 and 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 year ended December 31, 2019 and 2018, effectively all the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2 — Significant Accounting Policies.

Also noted under Note 2 — Significant Accounting Policies, a portion of the Partnership's revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. The Partnership uses its best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue we recognized.

During the year ended December 31, 2019, 2018 and 2017, the Partnership operated under a FERC approved 2016 rate settlement and as such, no revenues were subject to refund.

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 financial statements at December 31, 2017.

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

At December 31, 2019 and 2018, had legacy U.S. GAAP been applied, there would be no change in the Partnership's reported consolidated balance sheet and consolidated statements of comprehensive income line items.

Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under accounts receivable trade on the consolidated balance sheet. Additionally, the accounts receivable represents the Partnership's unconditional right to consideration for services completed which includes billed and unbilled accounts.

Right to invoice practical expedient

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 monthly once the Partnership's performance obligation to provide capacity has been satisfied.

NOTE 10 OTHER COMPREHENSIVE LOSS:

For the years ended December 31, 2019, 2018 and 2017, the accumulated balances related to other comprehensive (loss)/income consisted of the following (thousands of dollars):

	Adjustment to Retirement Benefit Plans	Other Adjustments	Accumulated Other Comprehensive (Loss)/Income
Balance as of 12/31/18	$(3,974)	$67	$(3,907)
Current-period other comprehensive income	2,146	162	2,308
Balance as of 12/31/19	**$(1,828)**	**$229**	**$(1,599)**

	Adjustment to Retirement Benefit Plans	Other Adjustments	Accumulated Other Comprehensive (Loss)/Income
Balance as of 12/31/17	$(1,517)	$131	$(1,386)
Current-period other comprehensive (loss)	(2,457)	(64)	(2,521)
Balance as of 12/31/18	$(3,974)	$67	$(3,907)

	Adjustment to Retirement Benefit Plans	Other Adjustments	Accumulated Other Comprehensive (Loss)/Income
Balance as of 12/31/16	$(3,264)	$48	$(3,216)
Current-period other comprehensive income	1,747	83	1,830
Balance as of 12/31/17	$(1,517)	$131	$(1,386)

NOTE 11 LEASES:

The Partnership's consolidated balance sheet beginning January 1, 2019 was impacted by the new lease accounting through the recognition of ROU assets and liabilities for operating leases. Amounts recognized at January 1, 2019 for operating were as follows (in millions):

At January 1	2019
ROU assets	**$8,283**
Short-term lease liability	**$1,086**
Long-term lease liability	**$7,197**

No impact was recorded to the beginning partners equity.

The Partnership leases its corporate office and one field office space under operating lease arrangements. The leases expire at various dates through 2022 and have the options to extend or terminate the leases. For purposes of calculating ROU asset and operating lease liabilities, the Partnership deemed that it was reasonable that they would exercise the 5 year extension of the agreement that is present in both lease contracts and included the 5 year extensions in the ROU assets and liabilities calculation.

Beginning January 1, 2019, ROU assets and lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. The following are the components of lease costs (in millions, except for lease terms and discount rate):

At December 31	2019
Operating lease costs	**$1,085**
Weighted average remaining lease term	**7.97 years**
Discount Rate	**4.08%**

Amounts recognized in the accompanying consolidated balance sheet are as follows (in millions):

Lease activity	Balance sheet location	2019
ROU assets	Other assets and deferred charges	**$7,520**
Short-term liability	Other current liabilities	**$1,101**
Long-term liability	Other liabilities	**$6,435**

Operating lease liabilities under non-cancellable leases (excluding short-term leases) as of December 31, 2019 (in millions):

Year	Amount
2020	$1.1
2021	$1.1
2022	$1.1
2023	$1.2
2024	$1.2
Thereafter	$3.3
Total lease payments	$9
Less: Interest	$(1.5)
Present value of lease liabilities	$7.5

Undiscounted future gross minimum operating lease payments as of December 31, 2018 were as follows (in millions):

Year	Amount
2019	$1.1
2020	$1.1
2021	$1.1
2022	$1.2
2023	$1.2
Thereafter	$4.5

NOTE 12 NON CASH INVESTING AND FINANCING ACTIVITIES:

ROU assets and operating lease obligations totaling $8,283 were recognized during the year ending December 31, 2019 (Refer to Note 11).

NOTE 13 RETIREMENT BENEFIT PLANS:

The Partnership has established a noncontributory cash balance retirement plan (the Plan) covering substantially all employees. Pension benefits are based on years of credited service and employees' career earnings, as defined in the Plan. The Partnership's funding policy is to contribute, annually, an amount at least equal to that which will satisfy the minimum funding requirements of the Employee Retirement Income Security Act (ERISA) plus such additional amounts, if any, as the Partnership may determine to be appropriate from time to time.

The Partnership also has adopted an excess benefit plan (EBP) that provides retirement benefits to executive officers. The EBP recognizes total compensation and service that would otherwise be disregarded due to Internal Revenue Code limitations on compensation in determining benefits under the regular retirement plan. The EBP is not considered to be funded for ERISA purposes and benefits are paid when due from general corporate assets. A Rabbi Trust, which is included in other assets and deferred charges on the Partnership's consolidated balance sheets, has been established to partially cover this obligation. The Rabbi Trust is an irrevocable trust which can be used to satisfy creditors.

The consolidated net cost for pension benefit plans included in the consolidated statements of comprehensive income for the years ending December 31 (which is the measurement date for each year), includes the following components (thousands of dollars):

	2019	2018	2017
Service cost	**$1,477**	$1,544	$1,553
Interest cost	**998**	843	885
Expected return on plan assets	**(1,817)**	(1,749)	(1,680)
Recognition of net actuarial loss	**140**	187	201
Net periodic benefit cost	**$798**	$825	$959

In the consolidated statements of operations, service cost is included in operation and maintenance expenses and the other components of net periodic benefit cost are included in other, net.

The following tables represent the Plans' combined funded status reconciled to amounts included in the consolidated balance sheets as of December 31, 2019 and 2018 (thousands of dollars):

Change in benefit obligation	2019	2018
Benefit obligation at beginning of year	**$24,746**	$24,814
Service cost	**1,477**	1,544
Interest cost	**998**	843
Actuarial loss/(gain)	**1,891**	(1,043)
Benefits Paid	**(230)**	(1,412)
Benefit obligation at end of year	**$28,882**	$24,746
Change in plan assets		
Fair value of plan assets at beginning of year	**$26,419**	$28,549
Actual return on plan assets	**5,714**	(1,939)
Employer contribution	**1,221**	1,221
Benefits Paid	**(230)**	(1,412)
Fair value of plan assets at end of year	**$33,124**	$26,419
Funded Status	**$4,242**	$1,673

Amount Recognized in Consolidated Balance Sheets Consisted of:	2019	2018
Non-current asset	**$5,656**	$2,770
Current liability	**(80)**	(50)
Non-current liability	**(1,334)**	(1,047)
Net amount recognized	**$4,242**	$1,673

	Plan Assets			Benefit Obligations		
	2019	2018	2017	2019	2018	2017
Plans in overfunded status	**$33,124**	$26,419	$28,549	**$27,468**	$23,649	$23,790
Plans in underfunded status	**—**	—	—	**1,414**	1,097	1,024

The accumulated benefit obligation for the Partnership's retirement benefit plans was $26.1 million, $24.7 million, and $24.8 million at December 31, 2019, 2018 and 2017, respectively.

Amounts recognized in accumulated other comprehensive income at December 31 (thousands of dollars):

	2019	2018	2017
Transition obligation	**—**	—	—
Prior service cost	**—**	—	—
Net loss	**$1,828**	$3,974	$1,517
Total Recognized in Accumulated Other Comprehensive Income	**$1,828**	$3,974	$1,517

Estimated net periodic benefit cost amortizations for the periods January 1 — December 31 (thousands of dollars):

	2020
Amortization of transition obligation	**—**
Amortization of prior service cost	**—**
Amortization of net loss	**$238**
Total Estimated Net Periodic Benefit Cost Amortizations	**$238**

The following table summarizes the weighted average assumptions used to determine benefit obligations as of December 31 (rates shown are rates at end of measurement period):

	Cash Balance Retirement Plan			Excess Benefit Plans		
	2019	2018	2017	2019	2018	2017
Discount rate	**3.15%**	4.15%	3.50%	**3.00%**	4.05%	3.45%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%

The following table summarizes the weighted average assumptions used to determine the net periodic benefit cost for years ended December 31 (rates shown are rates at beginning of measurement period)

	Cash Balance Retirement Plan			Excess Benefit Plans		
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
Discount rate	**4.15%**	3.50%	4.00%	**4.05%**	3.45%	3.85%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%
Expected long-term return on plan assets	**6.75%**	7.00%	7.00%			

The expected long-term rate of return assumption was developed using a variety of factors including long-term historical return information, the current level of expected returns and general industry expectations. Adjustments are made to the expected long-term rate of return assumption when deemed necessary based upon revised expectations of future investment performance of the overall capital markets. The building block methodology was used to generate the capital market assumptions, to the extent that the expected return has not shifted the long term expected rate will not be adjusted.

The discount rate was selected to reflect the rates of return currently available on high quality fixed income securities whose cash flows match the timing and amount of future benefit payments of the plan. In particular, the discount rate takes into consideration the population of our pension plan and the anticipated payment stream as compared to the FTSE Pension Liability Index (formerly called the Citi Pension Discount Curve).

The following table summarizes the expected future benefit payments over the next five years and aggregate five years thereafter (thousands of dollars):

Year	**Benefit Payment**
2020	$2,226
2021	$1,801
2002	$1,777
2023	$1,443
2024	$2,881
2025 — 2029	$11,162

Plan Assets

The following table sets forth the Partnership's pension plans weighted average asset allocations and target asset allocations, and fair value of the plan assets at December 31, 2019 and December 31, 2018.

	Weighted Average Asset Allocation		Plan Target Asset Allocation		Fair Value of Plan Assets (thousands of dollars)	
	2019	**2018**	**2019**	**2018**	**2019**	**2018**
Mutual Funds						
U.S. Equities	**38%**	36%	**38%**	35%	**$12,580**	$9,457
International Equities	**17%**	22%	**17%**	22%	**5,652**	5,787
Real Estate	**5%**	3%	**5%**	3%	**1,643**	931
U.S. Fixed Income	**39%**	36%	**39%**	37%	**12,910**	9,479
Other	**1%**	3%	**1%**	3%	**339**	765
Total					**$33,124**	$26,419

The Partnership's investment goal is to obtain a competitive risk adjusted return on the pension plan assets commensurate with prudent investment practices and the plan's responsibility to provide retirement benefits for its participants, retirees and their beneficiaries. The Plan's asset allocation targets are strategic and long term in nature and are designed to take advantage of the risk reducing impacts of asset class diversification.

Plan assets are periodically rebalanced to their asset class targets to reduce risk and to retain the portfolio's strategic risk/return profile. Investments within each asset category are further diversified with regard to investment style and concentration of holdings.

The Plan's investments are diversified to minimize the risk of a large loss. The Plan is constructed and maintained to provide prudent diversification among the asset classes in accordance with the asset allocation objectives. Within each asset class, there is prudent diversification with regard to investment styles and concentration of holdings.

Under the plans investment guidelines, the portfolio may contain mutual funds which are managed in accordance with the diversification and industry concentration restrictions set forth in the Investment Company Act of 1940, as amended (the 1940 Act). Pursuant to the provisions of the 1940 Act, a mutual fund may not, with respect to 75% of its assets, (i) purchase securities of any issuer (except securities issued or guaranteed by the United States Government, its agencies or instrumentalities) if, as a result, more than 5% of its total assets would be invested in the securities of such issuer; or (ii) acquire more than 10% of the outstanding voting securities of any one issuer.

In addition, no mutual fund may purchase any securities which would cause more than 25% of its total assets to be invested in the securities of one or more issuers conducting their principal business activities in the same industry, provided that this limitation does not apply to investments in securities issued or guaranteed by the United States Government, its agencies or instrumentalities.

All but one of the assets within Iroquois' Pension Plan are valued using Level 1 inputs in accordance with GAAP. As of December 31, 2019, one of the Plan's assets totaling $1.64 million is valued using Level 2 inputs, and the Partnership has the ability to redeem the asset or liability in the near term subsequent to the measurement date.

Contributions

Iroquois expects to contribute approximately $1.4 million to its pension plan in 2020.

Glossary of terms

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

2013 Term Loan Facility	TC PipeLines, LP's $500 million term loan credit facility under a term loan agreement as amended on September 29, 2017
2015 Term Loan Facility	TC PipeLines, LP's $170 million term loan credit facility under a term loan agreement as amended on 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	Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act, enacted on December 22, 2017
2018 FERC Actions	FERC's 2018 issuance of Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and a Final Rule that 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 quantified the rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by an MLP
2018 GTN Settlement	Stipulation and Agreement of Settlement for GTN regarding its rates and terms and conditions of service approved by FERC on November 30, 2018
2019 Iroquois Settlement	An uncontested settlement filed by Iroquois with FERC to address the issues contemplated by the 2017 Tax Act and the 2018 FERC Actions via an amendment to its prior 2016 settlement approved by FERC on May 2, 2019
2019 Tuscarora Settlement	An uncontested settlement filed by Tuscarora with FERC to address the issues contemplated by the 2017 Tax Act and the 2018 FERC Actions via an amendment to its prior 2016 settlement approved by FERC on May 2, 2019
ADIT	Accumulated Deferred Income Tax
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM program	At-the-market Equity Issuance Program
BIA	Bureau of Indian Affairs
Bison	Bison Pipeline LLC
C2C Contracts	PNGTS' Continent-to-Coast Contracts with several shippers for a term of 15 years for approximately 82,000 Dth/day
Canadian Mainline	TC Energy's Mainline, a natural gas transmission system extending from the Alberta/Saskatchewan border east to Quebec
Certificate Policy Statement NOI	FERC Notice of Inquiry issued on April 19, 2018

Class B Distribution	Annual distribution to TC Energy 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	Approximately 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
Delaware Act	Delaware Revised Uniform Limited Partnership Act
DOT	U.S. Department of Transportation
Dth/day	Dekatherms per day
DSUs	Deferred Share Units
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	U.S. Environmental Protection Agency
ExC Project	Iroquois Enhancement by Compression project that involves upgrading its compressor stations along the pipeline and provide approximately 125,000 Dth/day of additional firm transportation service to meet current and future gas supply needs of utility customers
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
General Partner	TC PipeLines GP, Inc.
GHG	Greenhouse Gas
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest LLC
GTN XPress	GTN project that will both increase the reliability of GTN's existing transportation service and provide up to 250,000 Dth/day of additional firm transportation service on the full path of the GTN system from Kingsgate, British Columbia, Canada to Malin, Oregon
HCAs	High consequence areas
IDRs	Incentive Distribution Rights
ILP Contribution	On December 31, 2018, General Partner contributed its 1.0101 percent general partner interest in each of the Partnership ILPs to the Intermediate GP and received a 1 percent general partner interest in the Partnership in return
ILPs	Intermediate Limited Partnerships
Intermediate GP	TC PipeLines Intermediate GP, LLC
IRS	Internal Revenue Service
Iroquois	Iroquois Gas Transmission System, L.P.

Joint Facilities	Pipeline facilities jointly owned with MNE on PNGTS
KPMG	KPMG LLP
LDCs	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
MLPs	Master limited partnerships
MNE	Maritimes and Northeast Pipeline LLC, a subsidiary of Enbridge Inc.
MNOC	M&N Operating Company, LLC, a wholly owned subsidiary of MNE
NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
North Baja XPress	North Baja potential project to transport additional volumes of natural gas of approximately 495,000 Dth/day between Ehrenberg, Arizona and Ogilby, California
Northern Border	Northern Border Pipeline Company
NYSE	New York Stock Exchange
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	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership
Partnership ILPs	TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
PXP	Portland XPress Project of PNGTS to re-contract certain system capacity set to expire in 2019 as well as construct incremental compression facilities within PNGTS' existing footprint in Maine
Revised Policy Statement	FERC's Revised Policy Statement on Treatment of Income Taxes
ROE	Return on equity
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Senior Credit Facility	TC PipeLines, LP's senior facility under revolving credit agreement as amended and restated, dated September 29, 2017
TC Energy	TC Energy Corporation, formerly known as TransCanada Corporation
TQM	TransQuebec and Maritimes Pipeline
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora XPress	Tuscarora's expansion project through additional compression capability at an existing Tuscarora facility and provide up to 15,000 Dth/day of additional firm transportation service
U.S.	United States of America

WCSB	Western Canadian Sedimentary Basin
Westbrook XPress	Westbrook XPress Project of PNGTS that is part of a coordinated offering to transport incremental Western Canadian Sedimentary Basin natural gas supplies to the Northeast U.S. and Atlantic Canada markets through additional compression capability at an existing PNGTS facility
VIEs	Variable Interest Entities
Wholly-owned subsidiaries	GTN, Bison, North Baja, and Tuscarora

Unless the context clearly indicates otherwise, TC PipeLines, LP and its subsidiaries are collectively referred to in this annual 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).

Corporate Information

Board of Directors [1]

Stanley G. Chapman, III
Chairman, TC PipeLines GP, Inc.
Executive Vice-President and President
U.S. Natural Gas Pipelines
TC Energy Corporation
Calgary, Alberta

Nathaniel A. Brown
President and Director
TC PipeLines GP, Inc.
Vice-President, U.S. Natural Gas Pipelines
Financial Services
TransCanada USA Services Inc.
Houston, Texas

Jack F. Stark [2] [3] [4]
Chief Financial Officer
Generate Capital, Inc.
Fremont, California

Malyn K. Malquist [5] [6]
Retired Executive Vice-President and
Chief Financial Officer
Avista Corporation
Spokane, Washington

Walentin (Val) Mirosh [4] [6]
President
Mircan Resources, Ltd.
Calgary, Alberta

Nadine E. Berge
Director, Corporate Compliance and
Legal Operations
TransCanada PipeLines Limited
Calgary, Alberta

Sean M. Brett
Senior Vice-President, Power and Storage
TransCanada PipeLines Limited
Calgary, Alberta

(1) Board of Directors of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP
(2) Lead Director
(3) Chair, Conflicts Committee
(4) Member, Audit Committee
(5) Chair, Audit Committee
(6) Member, Conflicts Committee

Officers [1]

Stanley G. Chapman, III
Chairman

Nathaniel A. Brown
President and Principal Executive Officer

Burton Cole
Controller

Janine M. Watson
Vice-President and General Manager

William C. (Chuck) Morris
Vice-President, Principal Financial Officer and Treasurer

Alisa Williams
Vice-President, Taxation

Jon A. Dobson
Secretary

(1) Officers of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP

TC PipeLines, LP
Investor Relations

Rhonda Amundson
Manager, Investor Relations
telephone: 1-877-290-2772
investor_relations@tcpipelineslp.com

700 Louisiana Street, Suite 700, Houston, TX
USA, 77002-2700
telephone: 1-877-290-2772

450 - 1 Street S.W. Calgary, AB
Canada, T2P 5H1
telephone: 1-877-290-2772

Website

TCPipeLinesLP.com

K-1 Information

telephone: 1-877-699-1091
www.taxpackagesupport.com/tcpipelines

Stock exchange listing

New York Stock Exchange: TCP

Auditor

KPMG LLP, Houston, TX

Transfer agent

Computershare
www.computershare.com/investor
telephone: 1-877-272-1556
online inquiries: www-us.computershare.com/investor/Contact

Mailing address

Computershare c/o Shareholder Services
P.O. BOX 505000, Louisville, KY
USA, 40233-5000

Courier address

Computershare c/o Shareholder Services
462 South 4 Street, Suite 1600, Louisville, KY
USA, 40202

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