TC PipeLines, LP

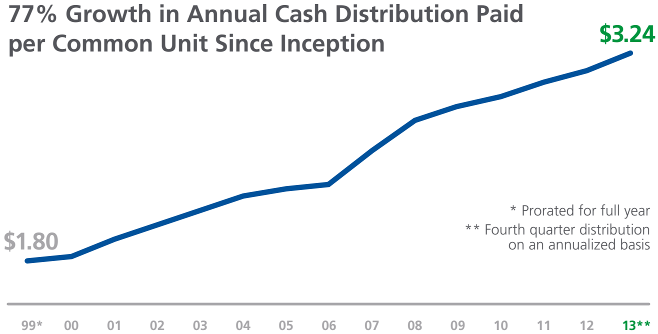
PROUD HISTORY MOVING FORWARD

2013 ANNUAL REPORT // TC PIPELINES, LP

2013 FINANCIAL HIGHLIGHTS

Year Ended December 31 (millions of dollars, except unit amounts)	2013 (2)	2012 (2)	2011 (2)	2010 (2)	2009 (2)(3)
Cash Flow					
Partnership cash flows (1)	195	202	222	180	150
Cash distributions paid	188	169	155	139	117
Income Statement					
Net income attributable to controlling interests	155	192	216	181	148
Balance Sheet					
Total assets	3,443	3,505	3,625	3,639	3,332
Long-term debt (including current maturities)	1,578	1,013	1,067	1,000	1,027
Partners' equity	1,789	2,422	2,496	2,254	1,967
Common Unit Statistics (per unit)					
Cash distributions paid	3.18	3.10	3.04	2.94	2.87
Net income	2.13	2.51	3.02	2.91	2.34
Common Units Outstanding (millions)					
Weighted average for the year	58.9	53.5	51.1	46.2	38.7
End of year	62.3	53.5	53.5	46.2	46.2

77% Growth in Annual Cash Distribution Paid per Common Unit Since Inception



(1) Partnership cash flows is a non-GAAP measure. 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, 2013, filed with the Securities Exchange Commission (SEC).

(2) The additional 45 percent membership interests in each of GTN and Bison were acquired from subsidiaries of TransCanada in 2013 resulting in a 70 percent ownership in each. As a result, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of GTN and Bison were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to consolidate GTN and Bison for all periods presented.

(3) The acquisition of North Baja from TransCanada in July 2009 was accounted for as a transaction between entities under common control, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

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.

LETTER TO UNITHOLDERS

Steve Becker

STEVE BECKER
President, TC PipeLines GP, Inc.

PROUD HISTORY

I am pleased to report that in 2013, TC PipeLines continued to further our strategy of generating long-term, stable and predictable distributions to our unitholders by completing our largest acquisition since our inception in 1999. This acquisition improved our portfolio by adding more assets with longer-term contracts with strong counterparties. With this transaction, we raised our quarterly distribution to you by three cents per unit or almost four percent which marks our 14th consecutive year of cash distribution growth. We are very proud of this track record.

The natural gas business continues to evolve with rapidly growing natural gas supplies and changes to traditional pipeline flow patterns, particularly in the eastern part of the country. Cold weather in late December and early 2014 demonstrated the need for pipeline infrastructure as many systems were pushed to their capacity limits. This highlights the value to our customers of holding long-term firm contracts which then translates into steady returns to you.

KEY ACCOMPLISHMENTS

Our portfolio of long-life, strong cash flow-generating pipeline assets continued to provide the basis for our success during the year where we:

- distributed $3.18 per unit, a three percent increase over our 2012 distribution
- acquired an additional 45 percent interest in each of Gas Transmission Northwest (GTN) and Bison for $1.05 billion, bringing our total interest in each to 70 percent
- raised $373 million in net equity proceeds to partially finance the GTN and Bison acquisitions
- entered into a new $500 million term loan facility with our syndicate of lenders to assist in financing the GTN and Bison acquisitions
- delivered earnings of $155 million or $2.13 per common unit with fourth quarter earnings generating $41 million of the total or $0.63 per common unit
- generated partnership cash flows of $195 million

In July, we closed the acquisition of additional interests in each of the GTN and Bison pipelines from TransCanada for $1.05 billion. This marks the largest transaction in our history. The acquisition strengthens our portfolio by further diversifying our sources of income and reducing our dependence on any one of our pipelines. GTN and Bison are both backed by long-term, ship-or-pay contracts which lengthen the contract terms underpinning our portfolio and heighten the stability of our revenues and cash flows.

PORTFOLIO PERFORMANCE

Our financial results reflect the increased size of our asset portfolio and the solid performance of our pipelines. We generated $195 million in partnership cash flows during the year on earnings of $155 million. Northern Border delivered strong results despite its lower rates which were instituted January 1. Demand for its service was strong and reflects its solid, cost-competitive position connecting Canadian, Rockies and Bakken gas to the mid-west U.S. GTN continued to increase revenues and flows due to strong demand in California and in the Pacific Northwest. Great Lakes settled its rate case with its shippers and is positioned for improved results going forward. Our other three assets showed steady results due to their fully contracted status. Overall, we believe that our portfolio of highly contracted pipeline assets continues to provide steady cash flows for you even in the face of some challenges at Great Lakes which is a testament to our diversified approach.

MOVING FORWARD

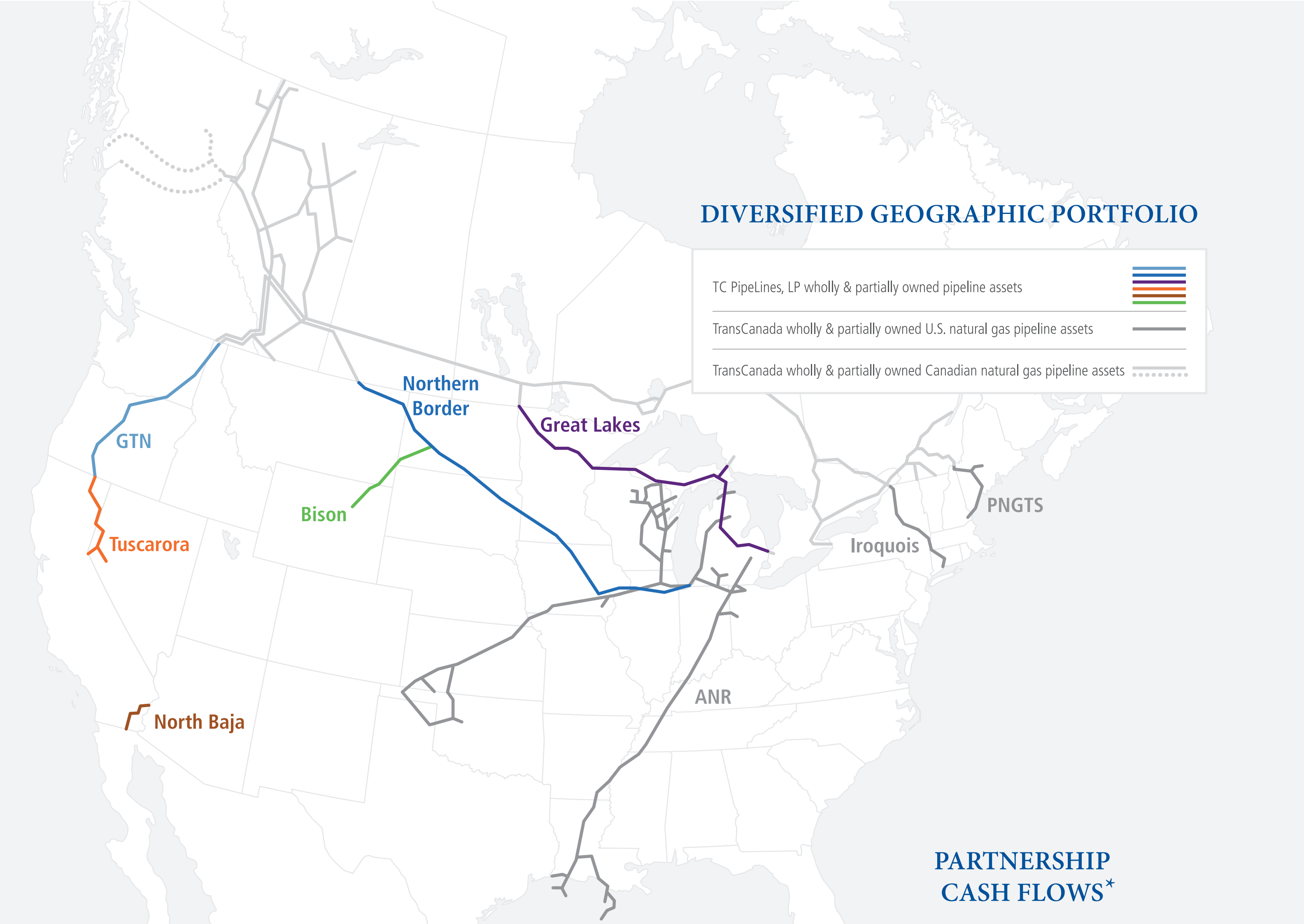
The North American outlook for natural gas as a key energy source remains strong. Demand for natural gas in North America is expected to grow by 15 Bcf/d over the remainder of the decade. This will present opportunities for growth and we are well positioned to capitalize on this potential.

In the near term, TC PipeLines expects to benefit from additional drop-downs from our general partner which has commercially secured $38 billion of capital projects to be completed by the end of the decade. This includes $13 billion in facilities underway in the natural gas business alone to connect new supplies with both domestic and overseas markets and an additional $25 billion in crude oil pipeline and power generation projects. In order to fund this substantial program, significant capital will be required and TransCanada expects to drop down the balance of its U.S. natural gas pipeline assets into our partnership as it proceeds through this program. These drop-downs have the potential to more than double the size of our asset base and will generate increased distributions and long-term value to you.

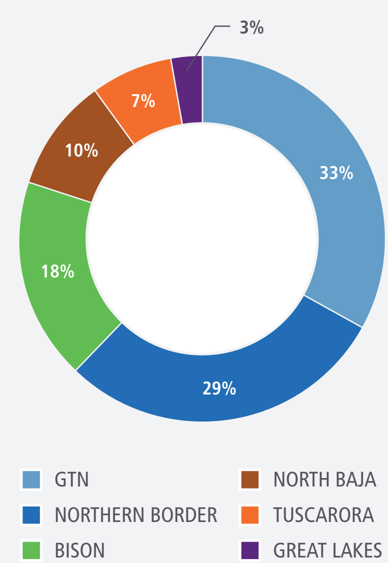
We're very proud of our history and are excited to build on our momentum as we move forward into 2014.

Thank you for your continued support.

DIVERSIFIED GEOGRAPHIC PORTFOLIO



PARTNERSHIP CASH FLOWS*



*Based on 2013 fourth quarter cash flows

PROUD HISTORY MOVING FORWARD

BISON

The Bison Pipeline is a new 303 mile natural gas pipeline originating from the Powder River Basin in Wyoming connecting to the Northern Border system in Morton County, North Dakota. Bison has long-term contracts all with terms expiring in 2021, for 407 million cubic feet per day (MMcf/d) comprising substantially all of Bison's capacity.

Our strategy is focused on generating long-term, stable and predictable distributions to our unitholders. Solid commercial and market fundamentals support our portfolio of natural gas pipeline assets. Revenue is derived almost entirely from commercial arrangements where payment is required, regardless of the volume of natural gas transported. This long-term contract-based business model creates consistent and reliable value for our unitholders.

ESSENTIAL INFRASTRUCTURE

Our pipelines provide critical connections between growing supply basins and large demand regions in North America and are capable of transporting 8.9 Bcf/d of Canadian and U.S. natural gas. We operate primarily in California, the Pacific Northwest and the Midwest and have a strong market position in these major regions.

GTN is our largest pipeline investment and provides a key service delivering gas out of Western Canada to local utilities and power generation facilities in the Pacific Northwest and California. 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 Rockies Basin and the Bakken formation in North Dakota, with key markets in Minneapolis and around Chicago. Our Great Lakes pipeline 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. Great Lakes is also an important regional supplier of gas to local utilities in the upper Midwest serving heating load areas in Michigan, Minnesota and Wisconsin. Our final three assets, Bison, North Baja and Tuscarora, are smaller in size but are critical infrastructure in their local markets.

> "OUR PIPELINES PROVIDE CRITICAL CONNECTIONS BETWEEN GROWING SUPPLY BASINS AND LARGE DEMAND REGIONS IN NORTH AMERICA."

LOW-RISK, CONTRACTED ASSETS

The majority of our cash flows are derived from long-term contracts at each of our pipelines. In 2013, virtually all of our partnership cash flows were from long-term contracts where shippers pay us for transportation capacity regardless of the volume of gas they actually ship. In the west, GTN's contracts mature between 2015 and 2023, Tuscarora is fully contracted through 2020, and North Baja's contracts mature between 2022 and 2031. In the mid-west, Northern Border's revenues are substantially contracted through June of 2015 with recent contract extensions generally three years or longer, and Bison's revenues are fully contracted through 2020. Great Lakes' contract mix is shorter-term but Great Lakes remains a critical transportation link to natural gas storage fields in Michigan and Southern Ontario and to major population centers in Minnesota, Wisconsin and Michigan. This was clearly demonstrated during the cold weather in December and January when Great Lakes was vital in delivering gas to local utilities to meet their heating load requirements.

The long-term contracted nature of our assets is further enhanced as our customers are very creditworthy with over 85 percent of our shippers of investment grade status.

SOLID FINANCIAL PERFORMANCE

Our most significant achievement in 2013 was the $1.05 billion acquisition of an additional 45 percent interest in each of GTN and Bison from TransCanada. Both are underpinned by long-term contracts. This was the single largest transaction in the history of our partnership allowing us to increase our quarterly distribution by almost 4 percent.

> "FUTURE DROP-DOWNS FROM TRANSCANADA HAVE THE POTENTIAL TO MORE THAN DOUBLE THE SIZE OF OUR ASSET BASE AND ULTIMATELY WILL SUPPORT OUR ABILITY TO PROVIDE GROWING AND SUSTAINABLE CASH FLOWS TO OUR UNITHOLDERS."

ENHANCED STABILITY

Rate certainty on our pipelines creates cash flow certainty and underpins the stable nature of our asset portfolio.

As part of our ongoing regulatory cycle, Great Lakes was required to file for new rates in 2013 and was successful in negotiating a rate settlement with shippers effective November 1, 2013. Under the settlement, Great Lakes' maximum rates increased by approximately 21 percent which positions Great Lakes to achieve improved results going forward.

With this settlement now in place, all of our pipelines have achieved rate certainty for the next few years. Northern Border and Great Lakes are not required to file for new rates until 2018. GTN is required to have new rates in place in 2016 while Tuscarora has no obligation to file for new rates. North Baja and Bison operate under long-term negotiated rates.

EVOLVING NATURAL GAS INDUSTRY

The natural gas industry has undergone major changes over the last few years with the development of the prolific shale gas reserves. The most impactful to our business has been the evolution of the Marcellus and Utica basins in the Northeast U.S. The resulting gas flows out of these basins have impacted transportation on natural gas pipelines such as Great Lakes as flow patterns have evolved. Currently, the majority of pipelines servicing the Northeast U.S. are fully contracted and producers are seeking additional takeaway capacity for their natural gas. This could result in improved utilization and revenues on our pipelines, particularly Great Lakes.

Along with this increase in natural gas supply, there is also an increased demand for natural gas as electrical generation and industrial sectors, along with residential users, are seeking to use natural gas for their power and heating needs.

GREAT LAKES

Great Lakes is a 2,115-mile interstate natural gas pipeline system serving major industrial and market centers in Minnesota, Wisconsin and Michigan. Safety and system integrity are key priorities and our safety performance remained in the top decile of our industry in 2013.

GTN

Gas Transmission Northwest (GTN) is a 1,353 mile interstate natural gas pipeline system that transports Western Canada Sedimentary Basin and Rocky Mountain sourced natural gas to third party natural gas pipelines and markets in Washington, Oregon and California.

In contrast to the historically warm winter a couple of years ago when demand for natural gas was very weak and prices and pipeline throughput were low, this winter has seen very cold temperatures with higher gas prices and stronger pipeline flows.

Despite these significant shifts, North America's gas infrastructure continues to provide reliable gas delivery service to customers across the country. And as the industry continues to evolve, we anticipate opportunities for expansion and growth.

POSITIONED FOR GROWTH

We are well positioned to capitalize on growth opportunities. We have a healthy balance sheet and a strong sponsor in TransCanada. Our investment grade credit ratings are indicative of our solid business platform and provide a firm basis from which to grow our business.

We assess the potential for third party acquisitions as well as organic expansion projects on our existing pipelines. GTN recently secured contracts with Portland General Electric to build a lateral pipeline to a power plant which will also result in additional long-term contracts on GTN's mainline system.

Additional drop-downs from TransCanada will also provide tangible future growth. TransCanada is in the midst of a substantial $38 billion capital program and expects to drop down the remainder of its U.S. gas pipeline asset portfolio into our partnership as its program progresses. This has the potential to more than double the size of our asset base and ultimately will support our ability to provide growing and sustainable cash flows to our unitholders.

GAS CONTROL – HOUSTON

TransCanada operates all of our assets and ensures reliable service to our customers. TransCanada's state-of-the-art control center monitors our pipelines 24/7.

TC PIPELINES, LP

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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 within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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, 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 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;
- changes in the taxation of master limited partnership investments by state or federal governments such as the 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), the U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT);
- our ongoing ability to grow distributions through acquisitions, accretive expansions or other growth opportunities;
- potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner), TransCanada and us;
- the ability to maintain secure operation of our information technology;
- the impact of any impairment charges;
- operating hazards, casualty losses and other matters beyond our control; and
- the level of our indebtedness, including the indebtedness of our pipeline systems, and the availability of capital.

These and other risks are described in greater detail in Part I, Item 1A. "Risk Factors." 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, formed by TransCanada Corporation and its subsidiaries (TransCanada) 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. Our common units are traded on the New York Stock Exchange (NYSE) under the symbol TCP.

We are managed by our General Partner, which is an indirect, wholly-owned subsidiary of TransCanada. Through its subsidiaries, TransCanada owns an approximate 28.9 percent equity interest in us, including a 26.9 percent limited partner interest and an effective two percent general partner interest held by our General Partner. See Part II, Item 5. "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for more information regarding TransCanada's ownership in us.

Recent Business Developments

Cash Distributions – In July 2013, we increased our quarterly distribution by 3.8 percent to $0.81 per common unit and during fiscal year 2013, we paid cash distributions totaling $3.18 per common unit. On February 14, 2014, we paid a cash distribution of $0.81 per common unit for the fourth quarter of 2013.

GTN – GTN and Portland General Electric Company (PGE) executed a Firm Transportation Service Agreement on December 11, 2013 for the approximately $54 million Carty lateral pipeline (Carty Lateral). The Carty Lateral is expected to be in-service in the fourth quarter of 2015 and will deliver natural gas to a PGE-owned power plant in Oregon. In addition to a 30-year contract for 100 percent of the 175,000 dekatherms per day (Dth/day) capacity of the Carty Lateral, PGE executed a 20-year GTN mainline contract for 75,000 Dth/day commencing in the second quarter of 2016.

Great Lakes Rate Settlement – On November 14, 2013, FERC approved a settlement between Great Lakes and Great Lakes' customers to modify its transportation rates effective November 1, 2013. The settlement increased maximum recourse transportation rates by approximately 21 percent. This will result in a modest increase in the portion of Great Lakes' revenue derived from its recourse rate contracts. See "Government Regulation – Regulatory and Rate Proceedings" for more information.

Term Loan Facility – On July 2, 2013, the Partnership borrowed $500 million under a new Term Loan Facility with a syndicate of lenders, which matures on July 1, 2018. The outstanding principal bears interest based on the London Interbank Offered Rate (LIBOR) plus an applicable margin.

GTN and Bison Additional Membership Interests Acquisition – On July 1, 2013, the Partnership acquired an additional 45 percent membership interest in each of GTN and Bison (the 2013 Acquisition) from subsidiaries of TransCanada. The total purchase price of the 2013 Acquisition was $1,050 million plus purchase price adjustments. The purchase price consisted of (i) $750 million for the GTN membership interest (less $146 million, which reflected 45 percent of GTN's outstanding debt at the time of the 2013 Acquisition), (ii) $300 million for the membership interest in Bison, (iii) $17 million in working capital adjustments and (iv) Carty Lateral consideration of $25 million. Refer to Item 15.

"Exhibits and Financial Statement Schedules" Note 6. "ACQUISITIONS" for additional disclosure regarding the 2013 Acquisition.

Equity Offering – On May 22, 2013, the Partnership completed a public offering of 8,855,000 common units at $43.85 per common unit for gross proceeds of $388 million and net proceeds of $373 million after unit issuance costs.

Business Strategies

- Our strategy is to invest 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 revenue opportunities 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 Pipelines Business

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs. Pipeline systems include meter stations that record how much natural gas comes on to the network and how much comes off 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 pipeline facilities and regulates certain aspects of ongoing operations 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. 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 the 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. Sometimes a settlement or agreement with the pipeline shippers is achieved, which may include mutually beneficial performance incentives. FERC must approve the components of any settlement.

Contracting

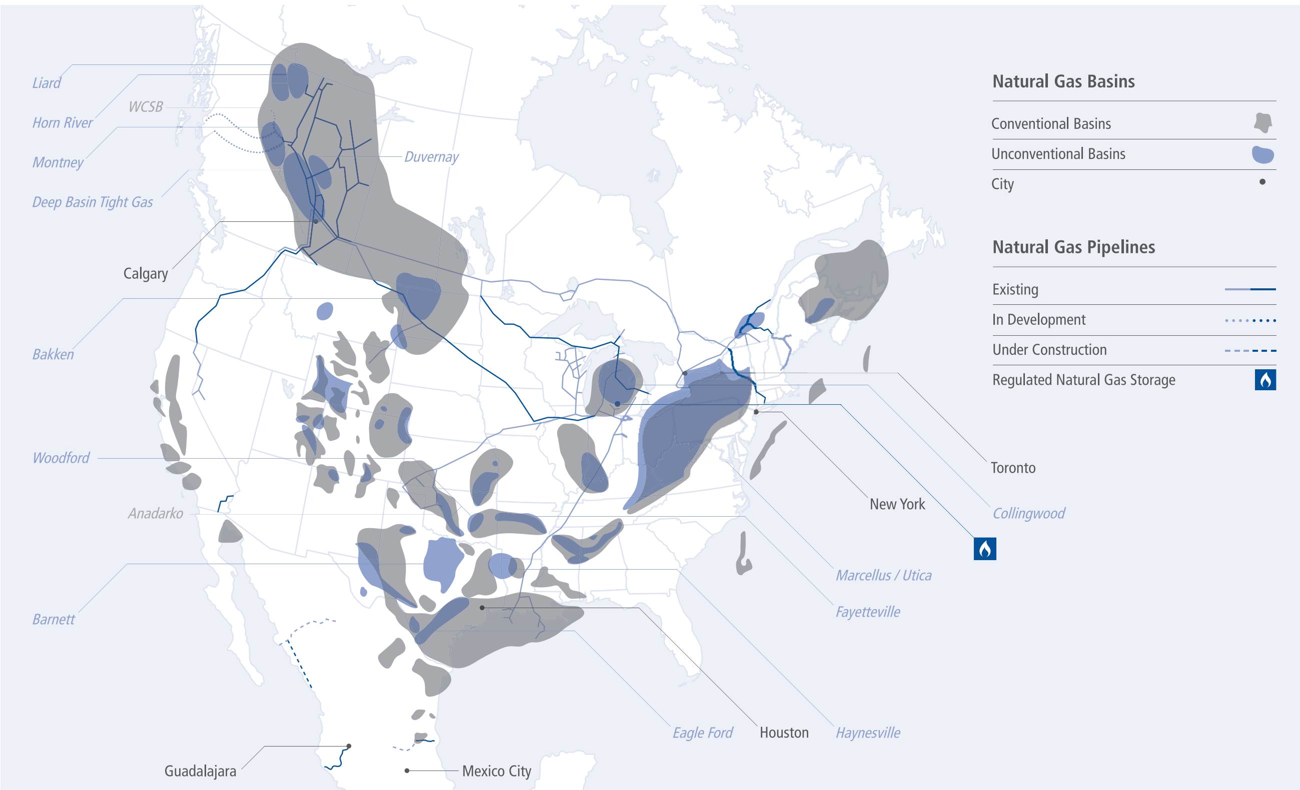
New pipeline projects are typically supported by long-term contracts. The term of the contracts is dependent on the individual developer's appetite for risk and is a function of expected rates of return and stability and certainty of returns. Transportation contracts expire at varying times and underpin 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, contracted at lower rates or 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, including factors such as:

- demand for natural gas;
- cost structures and production levels of natural gas producing basins;
- natural gas prices and regional differences in natural gas prices;

- weather conditions; and
- availability and location of natural gas supplies.

Business environment

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



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. Recent 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 existing markets, particularly in the Northeastern U.S. This has increased the number of supply choices for natural gas consumers and is changing historical natural gas pipeline flow patterns.

The supply of natural gas in North America is expected to increase significantly over the next decade and to continue to increase 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 (fracking), is allowing companies to access unconventional resources economically. This has increased the technically accessible resource base of existing basins and is opening up new producing regions; and

- application of these technologies to existing oil fields where further recovery of the existing resource is now possible. High oil prices, particularly compared to natural gas prices, has resulted in an increase in exploration and production of liquid-rich hydrocarbon basins. There are often incremental supplies of natural gas associated with these resources which, when produced, increase 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 slow drilling activities that in turn diminish production levels, particularly in dry natural gas fields where the extra revenue generated from the entrained liquids is not available;
- 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 fracking could impact the cost and pace of development of natural gas in these large shale and unconventional basins.

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 Alberta's oil sands;
- 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.

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 with 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.

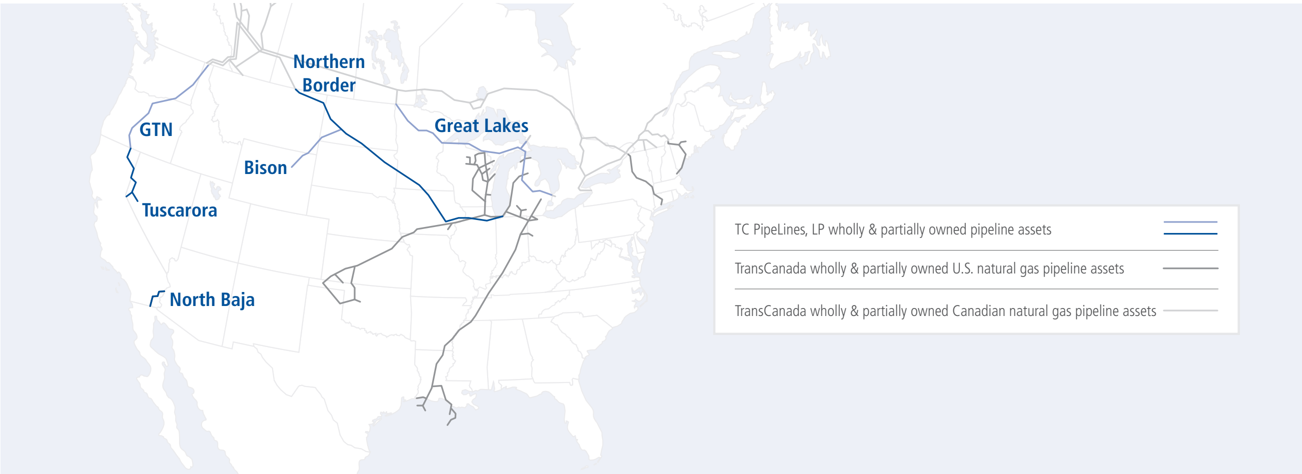
Our Pipeline Systems

We have equity ownership interests in two natural gas interstate pipeline systems that are accounted for on an equity basis, as well as two wholly-owned and two partially-owned pipelines that are accounted for on a consolidated basis. Collectively, they are designed to transport approximately 8.9 billion cubic feet per day of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western and Midwestern U.S. All of our pipeline systems are operated by subsidiaries of TransCanada.

Our pipeline systems include:

Pipeline	Length	Description	Ownership
GTN	1,353 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. TransCanada owns the remaining 30 percent of GTN.	70%
Northern Border	1,408 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 Williston Basin and Rocky Mountain Basin. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50%
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison was placed into service in January 2011 to transport natural gas from the Powder River Basin to Midwest markets. TransCanada owns the remaining 30 percent of Bison.	70%
Great Lakes	2,115 miles	Connects with the TransCanada 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. TransCanada owns the remaining 53.55 percent of Great Lakes.	46.45%
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. North Baja is a bi-directional pipeline.	100%
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%

The map below shows the location of our pipeline systems.



Customers, Contracting and Demand

Our customers are generally large utilities, local distribution companies (LDCs) and major natural gas marketers and producing companies. Our pipelines 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 and end users, to ensure our pipelines are offering attractive services and competitive rates.

In 2013, Anadarko Energy Services Company and Pacific Gas and Electric Company comprised 14 percent and 13 percent, respectively, of the Partnership's revenues.

GTN – GTN's revenues are substantially supported by long-term contracts. Contracts expiring prior to 2023 are primarily held by LDCs that historically use a diversified portfolio of transportation options to serve their long-term markets. We expect GTN to continue to be an important transportation component of these diversified portfolios. GTN's rates were established primarily based on its current contracted long-term capacity. As a result, GTN's revenues will be subject to positive variation as a result of capacity sold at levels above its current contracted amount.

Northern Border – Northern Border's revenues are substantially supported by firm transportation contracts through June 2015. As contracts have expired, market conditions allowed Northern Border to negotiate contract extensions that are typically for terms of three years or longer. Its uncontracted capacity is subject to seasonal demand for transportation services, which has traditionally been strongest during peak winter months to serve heating demand and peak spring/summer months to serve electric cooling demand and storage injection. Northern Border's tariff has a seasonal rate structure providing for higher rates during traditional peak months.

Great Lakes – Compared to our other pipelines, Great Lakes' revenue is derived from shorter-term contracts for short-haul transportation 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 price of natural gas liquids and the associated impact to North American natural gas production and competition. Demand for Great Lakes' services is usually highest in the summer, when the vast storage complexes in

Ontario and Michigan are typically being filled in advance of the upcoming winter season. During the winter, Great Lakes serves peak heating requirements for customers in Minnesota, Wisconsin, Michigan and beyond.

Other Pipelines – Bison, North Baja and Tuscarora revenues are substantially supported by long-term contracts through 2020.

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. When these long-term contracts expire, our pipeline systems face competitive pressures which influence contract renewals and rates charged for transportation services.

Four of our pipeline systems, GTN, Northern Border, Great Lakes and Tuscarora, compete with each other for WCSB natural gas supply as well as with other pipelines, including TransCanada's Mainline system, the Alliance pipeline and the Westcoast pipeline. Northern Border, Great Lakes and Tuscarora compete in their respective market areas for natural gas supplies from other basins as well, such as the Rocky Mountain, Mid-Continent, Gulf Coast, Appalachian 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 basin.

North Baja's southbound pipeline capacity competes with deliveries of LNG received at the Costa Azul terminal in Mexico. When LNG shipments are received at Costa Azul, North Baja's northbound capacity competes with pipelines that deliver Rocky Mountain, 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 Basin.

Relationship with TransCanada

TransCanada is the indirect parent of our General Partner and owns, through its subsidiaries, an approximate 28.9 percent equity interest in the Partnership. TransCanada is a major energy infrastructure company, listed on the Toronto Stock Exchange and NYSE, with more than 60 years of experience in the responsible development and reliable operation of energy infrastructure in North America. TransCanada is primarily focused on natural gas and oil transmission and power generation services. TransCanada owns approximately $54 billion in total assets, including 35,500 miles of wholly-owned natural gas pipelines, interests in an additional 7,000 miles of natural gas pipelines, 2,639 miles of wholly-owned oil pipelines and approximately 407 billion cubic feet of storage capacity. TransCanada also owns, controls or is developing over 11,800 megawatts of power generation.

TransCanada operates our pipeline systems and, in some cases, contracts for pipeline capacity. We have purchased assets from TransCanada and jointly participated with TransCanada in acquiring assets from third parties, including acquisitions that we would have been unable to pursue on our own. We may have similar opportunities going forward. TransCanada, however, is under no obligation to allow us to participate in any of its pipeline or energy infrastructure acquisitions, nor is TransCanada required to offer any of its assets to us.

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

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 virtually 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 creditworthiness 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 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.

Regulatory and Rate Proceedings

GTN – GTN has a FERC-approved settlement agreement for transportation rates that was effective January 2012, and these rates will remain in effect, subject to certain actions, until December 31, 2015. GTN is required to file for new rates to go into effect on January 1, 2016.

Northern Border – Northern Border has a FERC-approved settlement agreement which established maximum long-term transportation rates and charges on the Northern Border system effective January 1, 2013. The Northern Border Settlement also includes a three-year moratorium on filing rate cases and requires Northern Border to file for new rates no later than January 1, 2018.

Bison – Bison continues to operate under the rates approved by FERC in connection with Bison's initial construction and has no requirements to file a new rate proceeding.

Great Lakes – On November 14, 2013, FERC approved a settlement between Great Lakes and its customers to modify its transportation rates effective November 1, 2013. The settlement establishes maximum recourse transportation rates on the Great Lakes system. Commencing November 2013, rates increased, compared to previous rates, by approximately 21 percent. The settlement includes a moratorium on filing rate cases or challenging the settlement rates until March 31, 2015 and requires that Great Lakes file to have new rates in effect no later than January 1, 2018.

North Baja – North Baja continues to operate under the rates approved by FERC in 2004 in connection with North Baja's initial construction and has no requirements to file a new rate proceeding.

On January 6, 2014, FERC approved North Baja's application to temporarily abandon compression associated with the original design of its pipeline system. This temporary abandonment will preserve replacement options while reducing maintenance requirements and related expenses without any reduction in capacity or impact to existing firm transportation service.

Tuscarora – Tuscarora has a FERC-approved settlement agreement for transportation rates that was effective January 2012. The settlement includes three-year contract extensions for a number of contracts with Tuscarora's largest customer, and a moratorium on the filing of future rate proceedings until December 31, 2014. Tuscarora has no requirement to file for new rates.

Environmental

Our pipelines are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges and solid waste management. Such laws and regulations generally require natural gas pipelines to obtain and comply with a wide variety of environmental registrations, licenses, permits and other approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial requirements and/or the issuance of orders enjoining future operations.

The following is a discussion of some of the applicable environmental laws and regulations that relate to our business.

- *Waste and Hazardous Substance Statutes* – The operations of our pipeline systems are subject to the Resource Conservation and Recovery Act and comparable state statutes. Additionally, federal and state regulators have adopted strict disposal standards for non-hazardous industrial waste and hazardous substances, such as the Solid Waste Disposal Act and the Comprehensive Response, Compensation and Liability Act. These requirements are subject to rigorous waste management and disposal practices to ensure compliance.
- *The Clean Air Act (CAA)* – The CAA and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and impose various monitoring, reporting, and in some cases, control requirements. Such laws and regulations may require pre-approval for the construction or modification of certain facilities expected to produce air emissions or result in an increase of existing air emissions. Such facilities must also comply with air permits containing various emission and operational limitations, or requiring the use of emission control or abatement technologies.
- *Toxic Substances Control Act (TSCA)* – The TSCA addresses 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. These include polychlorinated biphenyls, asbestos, radon and lead-based paint.
- *The Clean Water Act (CWA)* – The CWA and comparable state laws impose strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into or adjacent to waters of the U.S. The discharge of pollutants into regulated waters is generally prohibited, except in accordance with the terms of a permit issued by the EPA or a delegated state or federal agency. The CWA and regulations implemented also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit.
- *National Environmental Policy Act (NEPA)* – Natural gas transportation activities can be subject to review under NEPA, or analogous federal or state requirements. NEPA requires federal agencies, including the Department of the Interior or FERC, to evaluate governmental agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that addresses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. The current activities of our pipeline systems, as well as any proposed plans for future activities, on federal lands are subject to the requirements of NEPA in connection with any new approval that is required for construction, operation or use on or of federal lands.
- *The Endangered Species Act (ESA)* – The ESA restricts activities that may affect endangered or threatened species or their habitats. The designation of previously unidentified or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

We have not incurred and do not anticipate incurring material costs to comply with existing environmental laws and regulations. We have not accrued for any environmental liabilities. We believe that we are in substantial compliance with all environmental laws and regulations.

Greenhouse Gas

Substantial uncertainty exists regarding the impact of new and proposed greenhouse gas (GHG) laws and regulations. Current legislative activities have focused on reporting of GHG, particularly methane, and not on the reduction of GHG. We cannot estimate the effect that proposed legislation may have on our future financial position, results of operations or cash flow. However, it is possible that such legislation could materially increase our operating costs, including our cost of environmental compliance. Because of the uncertainty of policy and regulatory schemes, the future impacts on our pipeline systems cannot be predicted.

Safety

Our pipeline systems are subject to existing and proposed pipeline safety regulations administered by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). In 2002 and 2006, federal pipeline safety statutes were enacted that apply to pipeline facility design, construction, installation, testing, operation, replacement and integrity management. These statutes and the associated regulations require pipeline companies to perform ongoing pipeline integrity assessments, to identify applicable threats to pipelines located in high consequence areas (HCAs) where a leak or rupture could potentially cause the most harm, to implement preventative and mitigative measures, and to repair and remediate pipelines as necessary. In compliance with these statutes and accompanying regulations, we apply an annual Integrity Management Program that evaluates our pipelines and results in measures to ensure the continued safe operation of our pipelines located in HCAs.

In January 2012, The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2012 Pipeline Act) was enacted. The 2012 Pipeline Act and the anticipated regulations that will follow impose a number of additional provisions affecting pipelines that may have a material effect on pipeline owners and operators. The 2012 Pipeline Act directs PHMSA to adopt regulations requiring the installation of leak detection equipment, the utilization of automatic and remote-controlled shut-off valves, the implementation of procedures to confirm the physical and operational characteristics and the maximum allowable operating pressure (MAOP) for pipelines in HCAs and areas other than HCAs; and the testing of grandfathered or previously untested natural gas transmission pipelines. It is expected that PHMSA will announce several new proposed regulations in the upcoming year related to the above areas which, if finalized, will result in significant increased costs to any new or existing pipelines and the potential for temporary or permanent reductions in MAOP, which would reduce available capacity on our pipelines.

While we believe that our pipeline systems are in substantial compliance with current applicable requirements, due to the possibility that new or amended statutes and regulations will be enacted, 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.

From time to time, despite compliance with applicable rules and regulations, our pipelines may experience incidents that result in leaks and ruptures that may impact the surrounding population and environment. This may result in enforcement by regulatory agencies that may seek civil and/or criminal fines and penalties.

EMPLOYEES

We do not have any employees. We are managed and operated by our General Partner. Subsidiaries of TransCanada operate our pipelines systems pursuant to operating agreements.

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 of the information contained in this report, including the following discussion of risks when making investment decisions relating to our Partnership.

RISKS RELATED TO THE PARTNERSHIP

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

Cash distributions are not dependent solely on our profitability. Therefore, we may make cash distributions during periods when losses are reported and may not make cash distributions during periods when we report profits.

Factors that affect the actual amount of cash that we will have available for distribution to our unitholders include the following:

- the amount of cash set aside and the adjustment in reserves made by our General Partner in its sole discretion;
- the amount of cash distributed to us by our pipeline systems;
- the level of capital expenditures made by our pipeline systems;
- the required principal and interest payments on our debt, retirement of debt and other liabilities, including cost of acquisitions;
- our ability to borrow funds and access capital markets, including the issuance of debt and equity securities; and
- restrictions on distributions contained in debt agreements.

If we do not successfully identify and complete expansion projects or make and integrate acquisitions that are accretive, we may not be able to continue to grow our cash distributions.

Our strategy is to continue to grow the cash distributions on our common units by expanding our business. Our ability to grow depends on our ability to undertake acquisitions and organic growth projects, and the ability of our pipeline systems to complete expansion projects and make and integrate acquisitions that result in an increase in cash per common unit generated from operations. Our ability to complete successful, accretive expansion projects or acquisitions is dependent upon many factors, including our ability to secure necessary rights-of-way or regulatory approvals, our ability to finance such expansion projects or acquisitions on economically acceptable terms and the degree to which our assumptions about volumes, reserves, revenues, costs and customer commitments materialize.

In addition, we face competition for acquisitions from investment funds, strategic buyers and commercial finance companies. These companies may have higher risk tolerances or different risk assessments that permit them to offer higher prices that we may be unwilling to match.

Expansion 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 expansion projects or make acquisitions that we believe will be accretive, these expansion projects or acquisitions may nevertheless reduce our cash from operations on a per-unit basis. Any expansion project or acquisition involves potential risks, including:

- an inability to complete expansion 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 expansion 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 debt could have negative 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;
- 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.

Our ability to service our debt will depend upon, among other things, the future financial and operating performance of our pipeline systems, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. In addition, the Partnership's third party credit facility requires us to maintain certain financial ratios and contains restrictions on incurring additional debt and making distributions to unitholders.

An impairment of our equity investment, long-lived assets or goodwill could reduce our earnings or negatively impact the value of our common units.

Consistent with GAAP, we evaluate our goodwill for impairment at least annually and our equity investments and long-lived assets, including intangible assets with finite useful lives, 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 as a whole, not 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 noncash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization.

As of December 31, 2013, no impairment has been identified related to our equity investments, long-lived assets or goodwill. There is a risk of a future impairment in our equity investment in Great Lakes if assumptions relied upon change. For more information, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of

Operations – Critical Accounting Estimates – Impairment of Equity Investments, Goodwill and Long-Lived Assets – Equity Investments.”

We do not own a controlling interest in Northern Border or Great Lakes, which limits our ability to control these assets.
We do not own a controlling interest in Northern Border or Great Lakes 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 organizational documents of these assets require distribution of their available cash to their owners on a quarterly basis; however, in each case, available cash is reduced, in part, by appropriate reserves. 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.

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, 2013, $730 million of our total $1,578 million consolidated debt was subject to variable interest rates. As a result, our results of operations, cash flows and financial condition could be materially 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, 2013, the variable interest rate exposure related to $150 million of the $500 million Term Loan Facility was hedged by fixed interest rate swap arrangements.

For more information about our interest rate risk, see Item 7A “Quantitative and Qualitative Disclosures About Market Risk – Market Risk.”

RISKS RELATED TO OUR PIPELINE SYSTEMS

Excess pipeline capacity in the markets we serve may lead to reduced demand for our transportation services or 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. The value of our transportation services depends on a shipper’s demand for pipeline capacity and the price paid for that capacity. The inability of our pipelines 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 prior contracts, depends on many factors including:

- 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; and
- regulatory developments.

Rates and other terms of service of our pipeline systems are subject to approval and potential adjustment by FERC, which could limit their ability to recover all costs of 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 nearly every aspect of their business, including the rates that they can charge to shippers. Under the NGA, our rates must be just, reasonable and not unduly discriminatory. Actions by FERC could adversely affect the ability of our pipeline systems to recover all of their current or future costs and negatively impact their rate of return, results of operations and cash available for distribution.

The long-term financial condition of our assets is 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 depends on numerous factors including basin production costs, production levels, availability of storage and natural gas prices. Our systems are also dependent on the continued demand for natural gas in our market areas. If supply and/or demand should significantly fall, our systems may be at risk for loss of contracting or contracting at discounted rates which could impact our revenues.

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 will 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 revenue and cash flows associated with return on the rate base will also decline.

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

Our pipeline systems' respective debt levels 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 or force majeure provisions.

Our pipeline systems are subject to inherent risks including earthquakes, adverse weather conditions and other natural disasters; terrorist activity or acts of aggression; damage to a pipeline by a third party; and explosions, pipeline failures, and safety failures. Each of these risks could result in damage to one of our pipeline systems, business interruptions, release of pollution or contaminants into the environment and other environmental hazards, or injuries to persons and property. These risks could cause us to suffer a substantial loss of revenue and incur significant costs to the extent they are not covered by insurance or considered a force majeure event under our shipper contracts, as applicable. In addition, if one of our pipeline systems was to experience a serious pipeline failure, a regulator could require our pipelines to conduct testing of the pipeline system or upgrade segments of a pipeline unrelated to the failure which costs may not be covered by insurance or recoverable through rate increases or face a potential reduction in operational parameters which could reduce the capacity available for sale.

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. PHMSA's regulations require pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and take measures to protect pipeline segments located in HCAs where a leak or rupture could do the most harm. The regulations require operators to perform ongoing assessments of pipeline integrity, identify applicable threats to pipeline segments that could affect HCAs, improve data collection and analysis, repair and remediate the pipelines as necessary and implement preventative and mitigating actions.

The ongoing implementation of the 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. Additionally, any failure to comply with PHMSA's regulations could subject our pipeline systems to penalties and fines.

In addition to the potential cost of compliance with current statutes and regulations, it is expected that PHMSA will propose additional regulations in the coming year. Though the content of the proposed regulations is not certain at this time, if those proposed regulations become final and enforceable, the cost of additional integrity management requirements to our pipeline systems 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.

Our pipeline systems are regulated by federal, state and local laws and regulations that could impose costs for compliance with environmental protection.

Each of our pipeline systems is subject to federal, state and local environmental laws, regulations and enforcement policies and potential liabilities may arise related to protection of the environment and natural resources. Existing or new environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs or the cost of any environmental remediation which may not be recoverable under their rates.

Under certain environmental laws and regulations, we may be exposed to substantial liabilities for pollution control or contamination that arise in connection with our operations. For instance, we may be required to obtain and maintain permits and approvals issued by various federal, state and local governmental authorities, and to limit or prevent releases of materials from our operations in accordance with these permits and approvals, or install pollution control equipment. In addition, various legislative and regulatory reforms associated with pipeline safety and integrity issues have been proposed, including reforms that would require increased periodic inspections. It is uncertain which proposed laws, regulations or reforms, if any, will be adopted and what impact they might ultimately have on our operations or financial results. Moreover, new environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs or the cost of any remediation of environmental contamination which may not be recoverable under their rates.

Current and future emissions regulation legislation or regulations restricting emissions of GHG could result in increased operating costs.

There have been a number of legislative initiatives to regulate GHG emissions; however, substantial uncertainty exists regarding the impact of new and proposed GHG laws and regulations. We cannot estimate the effect of proposed legislation on our future financial position, results of operations or cash flow. However, such legislation could materially increase our operating costs, including our cost of environmental compliance. Given the uncertainty of policy and regulatory schemes, the future effects on our pipelines cannot be predicted.

We are exposed to credit risk when a shipper 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 tariffs allow us to require limited credit support 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 us or contracted for with us, it could have a material adverse effect on our business and results of operations.

Our pipeline systems do not own all of the land on which their pipelines and facilities are located, which could impact their operations.
Our pipeline systems do not own all of the land on which their pipelines and facilities are located and they are, therefore, subject to the risk of increased costs to maintain necessary land use. They must either obtain the right from landowners or exercise the power of eminent domain in order to use most of the land on which they are constructed and operated. The loss of these rights, through their inability to renew right-of-way contracts, or increased costs to renew such rights could have a material adverse effect on our financial condition, results of operations and cash flows.

Our pipeline systems' business systems could be negatively impacted by security threats, including cyber security threats, and related disruptions.
We depend on the secure operation of our information technology to process, transmit and store electronic information, including information we use to safely operate our pipeline systems. Security breaches could expose our business to a risk of loss, misuse or interruption of critical information and functions that affect the pipeline operations. Such losses could result in operational impacts, damage to our assets, 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.

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.
As a limited partnership, 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.

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.

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. TransCanada's ownership of 26.9 percent of the outstanding common units 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 without unitholder approval, which would dilute the existing unitholders' ownership interests. In addition, issuance of additional common units 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 limited partner interests 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.

Unitholders may not have limited liability in some circumstances.
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 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, 2013, the General Partner and its affiliates own approximately 27 percent of our outstanding common units.

TransCanada, through its subsidiaries, controls our General Partner, which has responsibility for conducting our business and managing our operations. Our General Partner and its affiliates have limited fiduciary responsibilities and may have conflicts of interest with respect to our Partnership, and they may favor their own interests to the detriment of our unitholders.

The directors and officers of our General Partner and its affiliates have duties to manage the General Partner in a manner that is beneficial to its stockholders. At the same time, our General Partner has duties to manage the Partnership in a manner that is beneficial to us. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to its stockholders. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. Such conflicts may include, among others, the following situations:

- our General Partner is allowed to take into account the interests of parties other than us, such as TransCanada and its affiliates, in resolving conflicts of interest;
- TransCanada, through wholly-owned subsidiaries, is the operator of all of our pipeline systems. This operator role along with its ownership interests in some of our pipeline systems may influence TransCanada to make decisions that may conflict as operator and/or owner of these systems;
- our General Partner and its affiliates are not limited in their ability to compete with us;
- officers of our General Partner who provide services to us may also devote significant time to the business of TransCanada and are compensated by TransCanada for the services rendered to it;
- our General Partner may limit our liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, unitholders are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law; and
- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates.

Costs reimbursed to our General Partner are determined by our General Partner which could 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, 2013, we paid fees and reimbursements to our General Partner in the amount of $3 million (2012 – $3 million). 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.

TAX RISKS

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as not being subject to a material amount of entity level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for U.S federal income tax purposes or if we were to become subject to a material amount of entity level taxation, then our cash available for distribution would be substantially reduced.

The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income taxes on our taxable income at the applicable corporate tax rate, which is currently a maximum of 35 percent, 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. Because of a tax imposed upon us as a corporation, the cash available for distribution to our unitholders would be substantially reduced. Any tax treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of the common units.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units, may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal tax laws that could include changes affecting the tax treatment of publicly traded partnerships. We are unable to predict whether or not such changes, if any, will ultimately occur or become enacted.

Our pipeline systems are held in operating partnerships or limited liability companies, which are generally treated as flow-through entities for income tax purposes, and as such the income from our pipeline systems generally has not been subject to income tax at the entity level. Several states have either adopted or may be evaluating a variety of ways to subject partnerships and limited liability companies to entity level taxation. Imposition of such taxes on our pipeline systems would reduce the cash available for distribution to us and for other business needs by our pipeline systems, and could adversely affect the amount of funds available for distribution to our unitholders.

Any modification to the U.S. federal income or state tax laws or interpretation thereof, may be applied retroactively and could negatively impact the value of an investment in our units. 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 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 distributions to reflect the impact of that law on us.

We have not requested an IRS ruling with respect to our tax treatment.
We have not requested a ruling from the IRS with respect to any tax matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of the positions we take. Any contest with the IRS, and the outcome of any contest with the IRS, may materially and adversely impact the market for our common units and the price at which the common units trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by the unitholders and the General Partner.

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 their 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. 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.

Tax-exempt and non-U.S. investors may have adverse tax consequences from owning common units.
An investment in common units by tax-exempt entities and foreign persons raises issues unique to these persons. For example, virtually all of our income allocated to organizations which are exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to foreign persons will be reduced by withholding taxes imposed at the highest applicable effective tax rate, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income. Any tax-exempt or non-U.S. investors should consult their tax advisor before investing in our common units.

We treat a purchaser of common units as having the same tax benefits without regard to the actual common units purchased. A successful IRS challenge could adversely affect the value of the common units.
Because we cannot match transferors and transferees of common units, to maintain uniformity of the economic and tax characteristics of our common units, we have adopted depreciation and amortization conventions that do 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 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.
For income tax purposes and pursuant to the Partnership Agreement, when we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our General Partner. If our valuation methodology were not sustained upon an IRS challenge, there may be a shift of income, gain, loss and deduction between certain unitholders and the General Partner, which may be unfavorable to such unitholders. Our valuation methodology is also used in certain computations and allocations relating to tax basis adjustments and the tax treatment of unitholders' gain on sale of common units.

A successful IRS challenge to these methods, calculations or allocations could adversely affect the 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.

The sale or exchange of 50 percent or more of the total interest in our capital and profits will result in the termination of our Partnership for federal income tax purposes.
We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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 and conduct business in Arizona, California, Idaho, Illinois, Indiana, Iowa, Michigan, Minnesota, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, Texas,

Washington, Wisconsin and Wyoming. Should we make acquisitions or expand our business, we may own assets or conduct business in additional states. Most of these states currently impose personal income taxes on individuals. Generally, these states also impose income taxes on corporations and other entities. It is the unitholders' responsibility to file all required U.S. federal, state and local tax returns. Counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of the location and general character of our principal physical properties is included in Item 1. "Business" and is incorporated herein by reference.

We believe that our pipeline systems hold all rights, titles and interests in their respective pipeline systems. With respect to real property, our pipeline systems own or lease sites for compressor stations, meter stations, pipeline field offices and microwave towers. Our pipeline systems are constructed and operated on land owned by third parties, governmental authorities and others pursuant to leases, easements, rights-of-way, permits and licenses. We believe that our pipeline systems' properties are adequate and suitable for the conduct of their business in the future.

Northern Border – Approximately 90 miles of Northern Border's pipeline system is located within the boundaries of the Fort Peck Indian Reservation in Montana. Northern Border has a pipeline right-of-way lease 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, Northern Border also obtained right-of-way access across allotted lands located within the reservation boundaries. With the exception of three tracts subject to right-of-way grants expiring in 2015, 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 or obtained through condemnation. It is anticipated that the right-of-way grants for the three remaining tracts will be renewed by the BIA or, if necessary, obtained through condemnation.

Great Lakes – Approximately 74 miles of Great Lakes' pipeline system is located within the boundaries of three Indian reservations: the Leech Lake Chippewa Indian Reservation and the Fond du Lac Chippewa Indian Reservation in Minnesota, and the Bad River Chippewa Indian Reservation in Wisconsin. Great Lakes has right-of-way access, granted by the BIA, across allotted lands located within each reservation's boundaries that expire in 2018. Also, the Great Lakes pipeline crosses approximately 1,000 feet in two tracts under perpetual easement, located within the Chippewa Indian Reservation in Lower Michigan.

Item 3. Legal Proceedings

We are involved in various legal proceedings that arise in the ordinary course of business, as well as proceedings that we consider material under federal securities regulations. Information regarding our pipeline systems' rate proceedings described in Item 1. "Business – Government Regulation – Regulatory and Rate Proceedings" is incorporated herein by reference. We are also a party to the following legal proceedings:

GTN vs. PacifiCorp – In December 2009, PacifiCorp filed suit against GTN and Northwest Pipeline in Oregon State Court for approximately $7 million for alleged damage to equipment at its natural gas generating facility in Hermiston, Oregon. Upon GTN motion, the case was removed to the U.S. District Court for the District of Oregon and was scheduled for trial in March 2014. However, in February 2014, the parties settled all claims in the case. The impact on the Partnership's consolidated results was not material.

Great Lakes v. Essar Steel Minnesota LLC, et al. – On October 29, 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar Minnesota LLC and certain Essar affiliates (collectively, "Essar") for breach of its monthly payment obligation under its transportation services agreement with Great Lakes. Great Lakes sought to recover approximately $33 million for past and future payments due under the agreement. During the first quarter of 2013, the Federal District Court ruled favorably on a summary judgment motion for Great Lakes and dismissed Essar's defenses. During the second quarter of 2013, the parties resolved all outstanding issues. Trial on the damages is set to occur in early to mid-2014.

State of South Dakota Use Tax Appeal – On February 28, 2011, the State of South Dakota assessed a use tax in the amount of approximately $6 million on Northern Border for shipper supplied natural gas used to fuel compressors on Northern Border's pipeline system from July 1, 2007 to December 31, 2010. In November 2011, Northern Border filed a Request for Hearing with the South Dakota Department of Revenue to protest the assessment. A hearing was held on the matter in May 2012 and in the third quarter of 2013, the South Dakota Department of Revenue determined that the gas used by Northern Border to fuel compressors is taxable. In October 2013, Northern Border filed an appeal of this decision in the South Dakota Circuit Court, Sixth Judicial Circuit. Appellate briefs have been filed and oral argument is scheduled for March 3, 2014. As of December 31, 2013, Northern Border has recorded a liability of $11 million, including interest.

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 20, 2014, there were 60 registered holders of common units and approximately 31,592 beneficial owners of common units, including common units held in street name. Our common units trade on the NYSE under the symbol "TCP." Prior to December 2011, our units traded on the NASDAQ Stock Market.

We currently have 62,327,766 common units outstanding, of which 45,242,935 are held by the public, 11,287,725 are held by TransCan Northern Ltd., an indirect wholly-owned subsidiary of TransCanada, and 5,797,106 are held by our General Partner. The common units represent a 98 percent limited partner interest. Our General Partner holds an aggregate two percent general partner interest.

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported by the NYSE, and the amount of cash distributions declared per common unit with respect to the corresponding periods. Cash distributions are paid within 45 days after the end of each quarter to unitholders of record as of the record date.

	Price Range High	Price Range Low	Cash Distributions Declared per Common Unit
2013			
First Quarter	**$49.13**	**$40.60**	**$0.78**
Second Quarter	**$50.27**	**$42.16**	**$0.81**
Third Quarter	**$52.61**	**$45.69**	**$0.81**
Fourth Quarter	**$51.90**	**$43.06**	**$0.81**
2012			
First Quarter	$47.75	$44.27	$0.77
Second Quarter	$45.43	$38.20	$0.78
Third Quarter	$47.05	$42.67	$0.78
Fourth Quarter	$47.65	$38.74	$0.78

On February 14, 2014, we paid a cash distribution of $52 million to common unitholders and the General Partner, representing a cash distribution of $0.81 per common unit for the quarter ended December 31, 2013. The distribution was allocated in the following manner: $51 million to the common unitholders as of the close of business on January 28, 2014 (including $5 million to the General Partner as holder of 5,797,106 common units and $9 million to TransCanada as indirect holder of 11,287,725 common units), and $1 million to the General Partner in respect of its two percent general partner interest. In 2013, the Partnership made cash distributions to common unitholders and the General Partner that amounted to $188 million compared to $169 million in 2012.

Cash Distribution Policy

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. Our quarterly cash distributions to the unitholders comprise all of our Available Cash. Available Cash is defined in the Partnership Agreement and generally means, with respect to any quarter, all cash on hand at the end of a quarter less the amount of cash reserves that are necessary or appropriate, in the reasonable discretion of the General Partner, to:

- provide for the proper conduct of our business (including reserves for future capital expenditures and anticipated credit needs);
- comply with applicable laws or any debt instrument or other agreement to which we are subject; and
- provide funds for cash distributions to unitholders and the General Partner in respect of any one or more of the next four quarters.

Incentive Distributions

The incentive distribution provisions of the Partnership Agreement provide that the General Partner receives 15 percent of quarterly amounts distributed in excess of $0.81 per common unit, and a maximum of 25 percent of quarterly amounts distributed in excess of $0.88 per common unit, provided the balance has been first distributed to unitholders on a pro rata basis. The amounts that trigger incentive distributions at various levels are subject to adjustment in certain events, as described in the Partnership Agreement. In 2013 and 2012, we paid no incentive distributions to our General Partner.

Additional information about our cash distributions is included in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources" and Item 13. "Certain Relationships and Related Transactions, and Director Independence."

Item 6. Selected Financial Data

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

(millions of dollars, except per common unit amounts)	**2013[(a)]**	2012[(a)]	2011[(a)]	2010[(a)]	2009[(a)(b)]
Income Data (for the year ended December 31)					
Transmission revenues	**341**	343	353	286	285
Equity earnings from unconsolidated affiliates	**67**	99	135	126	99
Net income	**191**	229	250	200	166
Net income attributable to controlling interests	**155**	192	216	181	148
Basic and diluted net income per common unit[(c)]	**$2.13**	$2.51	$3.02	$2.91	$2.34
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$3.210**	$3.110	$3.060	$2.960	$2.895
Balance Sheet Data (at December 31)					
Total assets	**3,443**	3,505	3,625	3,639	3,332
Long-term debt (including current maturities)	**1,578**	1,013	1,067	1,000	1,027
Partners' equity	**1,789**	2,422	2,496	2,254	1,967

(a) An additional 45 percent membership interests in each of GTN and Bison were acquired from subsidiaries of TransCanada in 2013 resulting in a 70 percent ownership in each. As a result, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of GTN and Bison were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to consolidate GTN and Bison for all periods presented. Refer to Note 2 and Note 6 of the Partnership's Financial Statements included elsewhere in this report.

(b) The acquisition of North Baja from TransCanada in July 2009 was accounted for as a transaction between entities under common control, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

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

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

Management's Discussion and Analysis 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. 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.

The following discussion and analysis should be read in conjunction with Item 8. "Financial Statements and Supplementary Data."

EXECUTIVE OVERVIEW

We earned $155 million or $2.13 per common unit in 2013 compared to $192 million or $2.51 per common unit in 2012. Cash distributions paid increased eleven percent to $188 million while Partnership cash flows decreased four percent to $195 million. Our cash distribution coverage ratio was 1.06 times in 2013 compared to 1.21 times in 2012.

GTN and Bison Additional Membership Interests Acquisition – On July 1, 2013, the Partnership acquired additional 45 percent membership interests in each of GTN and Bison from subsidiaries of TransCanada.

Equity Offering – On May 22, 2013, the Partnership completed a public offering of 8,855,000 common units at $43.85 per common unit for gross proceeds of $388 million and net proceeds of $373 million after unit issuance costs.

Term Loan Facility – On July 2, 2013, the Partnership borrowed $500 million under a new Term Loan Facility with a syndicate of lenders, which matures on July 1, 2018.

Outlook of Our Business

TransCanada, the ultimate parent company of our General Partner, is currently executing a $38 billion capital program through 2020, including $12 billion through 2015. TransCanada's management has indicated that they expect to drop down all of their remaining U.S. natural gas pipeline assets into the Partnership, as it proceeds through its capital program. The option for TransCanada to raise capital through the use of further drop-downs to the Partnership has the potential to more than double the size of the Partnership's assets.

In 2014, the Partnership's portfolio of six FERC-regulated interstate natural gas pipelines, five of which are backed by long-term, ship-or-pay contracts, is expected to deliver higher Partnership Cash flows as compared to 2013 primarily due to the increased membership interests in GTN and Bison. Great Lakes is expected to continue to contract largely on a short-term, short-haul basis; however, the higher recourse rates resulting from its recent settlement with shippers provide it with a greater opportunity to generate additional revenues as market conditions allow. Management expects transportation revenues from our current pipeline systems in 2014 to be comparable to 2013.

HOW WE EVALUATE OUR OPERATIONS

We evaluate our business primarily on the basis of the underlying operating results for each of our pipeline systems along with a measure of Partnership cash flows. This measure does not have a standardized meaning prescribed by GAAP. It is, therefore, considered to be a non-GAAP measure and is unlikely to be comparable to similar measures presented by other entities. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Partnership Cash Flows".

RESULTS OF OPERATIONS

Our general partner interests in Northern Border and Great Lakes, and ownership of GTN, Bison, North Baja and Tuscarora were our only material sources of income in 2013. Therefore, our results of operations and Partnership cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems. See Item 1. "Business."

To supplement our financial statements, we have presented a comparison of the earnings contribution components from each of our investments. We have presented net income attributable to controlling interests in this format to enhance investors' understanding of the way management analyzes our financial performance. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

Partnership Results of Operations

(millions of dollars)	**2013[a]**	2012[a]	2011[a]
Net income:			
GTN	**75**	78	70
Bison	**46**	44	42
North Baja	**22**	21	22
Tuscarora	**16**	15	18
Equity earnings:			
Northern Border	**64**	72	75
Great Lakes	**3**	27	60
Partnership expenses	**(35)**	(28)	(37)
Net income	**191**	229	250
Net income attributable to non-controlling interests	**36**	37	34
Net income attributable to controlling interests	**155**	192	216

[a] Financial information was recast to consolidate GTN and Bison for all periods presented.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

Net income attributable to controlling interests decreased $37 million to $155 million in 2013 compared to $192 million in 2012. This decrease was primarily due to lower equity earnings from Great Lakes and Northern Border and higher Partnership expenses.

Equity earnings from Great Lakes were $3 million in 2013, a decrease of $24 million compared to 2012. The decrease was primarily due to lower revenue resulting from capacity contracted at lower rates and volumes in 2013 compared to 2012.

Equity earnings from Northern Border were $64 million in 2013, a decrease of $8 million compared to 2012. This was primarily due to the 11 percent reduction in reservation rates resulting from the Northern Border Settlement which became effective in January 2013.

Partnership expenses were $35 million in 2013, an increase of $7 million compared to the same period in 2012. This increase was primarily due to acquisition and interest expenses incurred in relation to the 2013 Acquisition.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011

Net income attributable to controlling interests decreased $24 million to $192 million in 2012 compared to $216 million in 2011. This decrease was primarily due to lower equity earnings from Great Lakes, partially offset by lower Partnership expenses.

Equity earnings from Great Lakes were $27 million in 2012, a decrease of $33 million compared to 2011. The decrease in equity earnings was primarily due to lower transportation revenue from unsold long-haul winter capacity in the first and fourth quarters of 2012, and summer capacity sold for a shorter term at lower rates in the second and third quarters of 2012 compared to the same periods of 2011.

Costs at the Partnership level decreased $9 million to $28 million in 2012 compared to 2011. This decrease was due to one-time costs incurred in 2011 related to the 2011 Acquisition, as well as a decrease in financial charges resulting from a lower average debt balance and the use of floating rate debt in 2012.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity include distributions received from our investments in partially owned affiliates, operating cash flows from our subsidiaries, public offerings of debt and equity, term loans and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

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. Our pipeline systems have historically funded operating expenses, debt service and cash distributions to their owners primarily with operating cash flow. However, since the fourth quarter of 2010, Great Lakes has funded its debt repayments with cash calls to its owners. Northern Border also funded $62 million of debt repayment in 2013 with a cash call to its owners.

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

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

Our cash flow is based on the distributions from our portfolio of six pipelines. Overall, we believe that our pipeline systems' ability to obtain financing at reasonable rates, together with a history of consistent cash flow from operating activities, provide a solid foundation to meet future liquidity and capital requirements. We expect to be able to fund our liquidity requirements, including our distributions, at the Partnership level, over the next 12 months utilizing our cash flow and our existing Senior Credit Facility if required.

Partnership Cash Flows

The Partnership uses the non-GAAP financial measures "Partnership cash flows" and "Partnership cash flows before General Partner distributions" as they provide a measure of cash generated during the period to evaluate our cash distribution capability. As well, management uses these measures as a basis for recommendations to our General Partner's board of directors regarding the distribution amount to be declared each quarter. Partnership cash flow information is presented to enhance investors' understanding of the way that management analyzes the Partnership's financial performance.

Partnership cash flows include net income attributable to controlling interests, less net income attributed to GTN's and Bison's former parent, plus operating cash flows from North Baja and Tuscarora, and cash distributions received from GTN, Northern Border, Bison and Great Lakes, less equity earnings from unconsolidated affiliates and Other Pipes' net income as previously reported, plus net income attributable to non-controlling interests from consolidated subsidiaries after the 2013 Acquisition, and net of distributions declared to the General Partner. Partnership cash flows before General Partner distributions represent Partnership cash flows prior to distributions paid to the General Partner.

Partnership cash flows and Partnership cash flows before General Partner distributions are provided as a supplement to GAAP financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP.

Non-GAAP Measures
Reconciliations of Net Income Attributable to Controlling Interests to Partnership Cash Flows

Year Ended December 31 *(millions of dollars except per common unit amounts)*	**2013**	2012	2011
Net income attributable to controlling interests[d]	**155**	192	216
Less net income attributed GTN's and Bison's former parent[d]	**(26)**	(55)	(59)
Net income as previously reported	**129**	137	157
Add:			
Cash distributions from GTN[a]	**54**	28	33
Cash distributions from Northern Border[a]	**84**	96	99
Cash distributions from Bison[a]	**29**	16	6
Cash distributions from Great Lakes[a]	**17**	44	73
Cash flows provided by North Baja's and Tuscarora's operating activities	**50**	49	52
	234	233	263
Less:			
Equity earnings as previously reported:			
GTN	**(9)**	(19)	(12)
Northern Border	**(64)**	(72)	(75)
Bison	**(6)**	(11)	(7)
Great Lakes	**(3)**	(27)	(60)
	(82)	(129)	(154)
Less:			
Other Pipes' net income as previously reported[e]			
GTN	**(39)**	–	–
Bison	**(23)**	–	–
North Baja	**(22)**	(21)	(23)
Tuscarora	**(16)**	(15)	(18)
	(100)	(36)	(41)
Add:			
Net income attributable to non-controlling interests after the 2013 Acquisition	**18**	–	–
Partnership cash flows before General Partner distributions	**199**	205	225
General Partner distributions[b]	**(4)**	(3)	(3)
Partnership cash flows	**195**	202	222
Cash distributions declared	**(197)**	(170)	(161)
Cash distributions declared per common unit[c]	**$3.21**	$3.11	$3.06
Cash distributions paid	**(188)**	(169)	(155)
Cash distributions paid per common unit[c]	**$3.18**	$3.10	$3.04

[a] In accordance with the cash distribution policies of the respective entities, cash distributions from GTN, Northern Border, Bison and Great Lakes, are based on their respective prior quarter financial results. Distributions from GTN and Bison are based on 70 percent ownership starting from July 1, 2013. In fourth quarter 2011, GTN distributed $5 million and $8 million for the second and third quarters, respectively. In addition, in fourth quarter 2011, GTN paid a one-time distribution of $20 million related to its cash balance at the time of the 2011 Acquisition.

[b] General Partner distributions represent the cash distributions paid to the General Partner with respect to its two percent interest plus an amount equal to incentive distributions. Incentive distributions in 2013, 2012 and 2011 were nil.

[c] Cash distributions declared per common unit and cash distributions paid per common unit are computed by dividing cash distributions, after the deduction of the General Partner's allocation, by the number of common units outstanding. The General Partner's allocation is computed based upon the General Partner's two percent interest plus an amount equal to incentive distributions.

[d] Financial information was recast to consolidate GTN and Bison for all periods presented. Prior to the 2013 Acquisition, our net income was $137 million and $157 million for the years ended December 31, 2012 and 2011, respectively, reflecting our actual ownership in each of GTN and Bison at that time. As a result of the recast, net income is $192 million and $216 million for the years ended December 31, 2012 and 2011, respectively, as if we owned 70 percent in each of GTN and Bison. Net income attributed to GTN and Bison's former parent of $55 million and $59 million, reflecting the acquired ownership interests not then owned by the Partnership, for the years ended December 31, 2012 and 2011, respectively, reconciles the net income as previously reported and net income attributable to controlling interests.

[e] "Other Pipes" includes the results of North Baja and Tuscarora and, after July 1, 2013, GTN and Bison as well.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

Partnership cash flows decreased $7 million to $195 million in 2013 compared to $202 million in 2012. This decrease was primarily due to lower cash distributions from Great Lakes of $27 million and Northern Border of $12 million as compared to the same period of 2012, consistent with the reductions in earnings previously discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations." This was offset by increased cash distributions of $39 million from GTN and Bison as a result of the 2013 Acquisition.

The Partnership paid cash distributions of $188 million in 2013, an increase of $19 million compared to 2012. This increase is due to a $0.03 increase in the distribution per common unit in July 2013, as well as an increase in the number of common units outstanding resulting from the equity issuance in May 2013.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011

Partnership cash flows decreased $20 million to $202 million in 2012 compared to $222 million in 2011. This decrease was primarily due to decreased cash distributions from Great Lakes of $29 million, partially offset by an increase in cash distributions from Bison of $10 million.

The Partnership paid cash distributions of $169 million in 2012, an increase of $14 million compared to 2011 due to an increase of $0.06 per common unit paid and an increase in the average number of common units outstanding as compared to 2011.

Other Cash Flows

On July 1, 2013, the Partnership acquired an additional 45 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada. The Partnership paid $921 million in respect of this acquisition in 2013. It was financed with net proceeds from an equity issuance of $373 million, borrowing of $500 million in term loans, an $8 million capital contribution from the General Partner, a draw under the Senior Credit Facility and cash on hand. Refer to Item 15. "Exhibits and Financial Statement Schedules" Note 6 "ACQUISITIONS" for additional disclosure regarding the 2013 Acquisition.

In November 2013, the Partnership made an equity contribution totaling $31 million to Northern Border to fund repayment of the Northern Border Credit Facility.

In the second quarter of 2013, Bison's former parent made an equity contribution to Bison of $18 million which was used to repay inter-affiliate debt primarily related to pipeline construction costs, including reclamation and restoration work.

In March and October of 2013, the Partnership made equity contributions totaling $9 million to Great Lakes to fund debt repayments.

On May 3, 2011, the Partnership acquired 25 percent membership interests in GTN and Bison with net proceeds from an equity issuance of $331 million, draws on a bridge loan facility and Senior Credit Facility of $61 million and

$125 million, respectively, a $7 million capital contribution from the General Partner and cash on hand. Also in 2011, the Partnership made equity contributions of $9 million to Great Lakes to fund debt repayments, a $50 million equity contribution in accordance with Northern Border's distribution policy in order to meet minimum equity to total capitalization requirements, and an equity contribution of $5 million to fund Northern Border's Princeton Lateral project. Pursuant to an amendment to the acquisition agreement between the Partnership and TransCanada, in 2011 the Partnership made an additional payment of $2 million in connection with the North Baja Yuma Lateral for the additional contract secured by TransCanada when the facilities associated with the additional contract were completed. In 2011, Bison's former parent made an equity contribution to Bison of $305 million related to pipeline system construction costs.

Contractual Obligations

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2013 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Senior Credit Facility due 2017	380	–	–	380	–
Term Loan Facility due 2018	500	–	–	500	–
4.65% Senior Notes due 2021	349	–	–	–	349
5.09% Senior Notes due 2015	75	–	75	–	–
5.29% Senior Notes due 2020	100	–	–	–	100
5.69% Senior Notes due 2035	150	–	–	–	150
3.82% Series D Senior Notes due 2017	24	3	9	12	–
Interest on Debt Obligations[a]	400	47	88	76	189
Operating Leases	6	1	1	1	3
	1,984	51	173	969	791

[a] Interest payments on floating-rate debt are estimated using interest rates effective as of December 31, 2013.

The Partnership's Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, maturing November 20, 2017, under which $380 million was outstanding at December 31, 2013 (2012 – $312 million).

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be lenders' base rate or 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 $250 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 averaged 1.44 percent for the year ended December 31, 2013 (2012 – 1.61 percent).

On July 2, 2013, the Partnership borrowed $500 million under a new Term Loan Facility with a syndicate of lenders, which matures on July 1, 2018. The outstanding principal amount bears interest based, at the Partnership's election, on the LIBOR or the base rate plus, in either case, an applicable margin.

The LIBOR based interest rate on the Term Loan Facility averaged 1.43 percent for the year ended December 31, 2013. After hedging activity, the interest rate incurred on the Term Loan Facility averaged 1.70 percent for the year ended December 31, 2013. Prior to hedging activities, the LIBOR-based interest rate was 1.42 percent at December 31, 2013.

The Senior Credit Facility and the Term Loan Facility require the Partnership to maintain a leverage ratio (debt to adjusted cash flow (net income plus cash distributions received, extraordinary losses, interest expense, expense for taxes paid or accrued, and depreciation and amortization expense less equity earnings and extraordinary gains)) of no more than 5.00 to 1.00 at the end of each fiscal quarter. The permitted leverage ratio will increase to 5.50 to 1.00 for the fiscal quarter in which a specified material acquisition occurs and for the two fiscal quarters immediately following such acquisition, after which the permitted leverage ratio reverts to 5.00 to 1.00. The leverage ratio was 4.17 to 1.00 as of December 31, 2013. The Senior Credit Facility and the 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 Term Loan Facility may become immediately due and payable.

GTN's Senior Notes provisions contain a covenant that limits total debt to no greater than 70 percent of total capitalization.

Series D Senior Notes are secured by Tuscarora's transportation contracts, supporting agreements and substantially all of Tuscarora's property. The note purchase agreements contain certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners.

At December 31, 2013, the Partnership was in compliance with its financial covenants.

The fair value of the Partnership's long-term debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates. The estimated fair value of the Partnership's long-term debt at December 31, 2013 was $1,597 million. As of February 28, 2014, the Partnership had $370 million outstanding under the Senior Credit Facility.

Capital Requirements

The Partnership is expected to make equity contributions totaling $9 million to Great Lakes in 2014 for scheduled debt repayments.

GTN will spend approximately $54 million to build the Carty Lateral which is expected to be in-service in the fourth quarter of 2015. The Partnership's share is 70 percent or $38 million.

The Partnership will pay $25 million of additional consideration in accordance with the 2013 Acquisition with respect to Carty Lateral to a subsidiary of TransCanada by April 2014.

To the extent the Partnership has any additional capital requirements with respect to our pipeline systems or acquisitions in the future, we expect to fund these requirements with operating cash flows, debt and/or equity.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2013 included the following:

		Payments Due by Period[a]			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.24% Senior Notes due 2016	100	–	100	–	–
7.50% Senior Notes due 2021	250	–	–	–	250
$200 million Credit Agreement due 2016	62	–	62	–	–
Interest payments on debt	170	26	50	38	56
Operating leases	59	2	4	4	49
Other long-term obligations	4	4	–	–	–
	645	32	216	42	355

[a] Represents 100 percent of Northern Border's contractual obligations.

Senior Notes

All of Northern Border's outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums. 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, 2013, Northern Border was in compliance with all of its financial covenants.

At December 31, 2013, the aggregate estimated fair value of Northern Border's long-term debt was approximately $462 million (2012 – $545 million). In 2013, interest expense related to the senior notes was $25 million (2012 – $25 million; 2011 – $25 million).

Credit Agreement

Northern Border's credit agreement consists of a $200 million revolving credit facility. At December 31, 2013, $62 million was outstanding leaving $138 million available for future borrowings. 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, 2013 was 1.37 percent (2012 – 1.34 percent). At December 31, 2013, Northern Border was in compliance with all of its financial covenants.

Operating Leases

Northern Border is required to make future minimum payments for office space and rights-of-way under non-cancelable operating leases.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations as of December 31, 2013 included the following:

		Payments Due by Period[a]			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.73% series Senior Notes due 2014 to 2018	45	9	18	18	–
9.09% series Senior Notes due 2014 to 2021	80	10	20	20	30
6.95% series Senior Notes due 2019 to 2028	110	–	–	–	110
8.08% series Senior Notes due 2021 to 2030	100	–	–	–	100
Interest payments on debt	214	26	47	41	100
	549	45	85	79	340

[a] Represents 100 percent of Great Lakes' contractual obligations.

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 $180 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2013 (2012 – $191 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2013.

The aggregate estimated fair value of Great Lakes' long-term debt was $410 million at December 31, 2013 (2012 – $536 million). The aggregate annual required repayment of senior notes is $19 million for each year 2014 through 2018. In 2013, interest expense related to Great Lakes' senior notes was $27 million (2012 – $28 million; 2011 – $30 million).

Other

Great Lakes has a cash management agreement with TransCanada whereby Great Lakes' funds are pooled with other TransCanada affiliates. The agreement also gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for Great Lakes' operating needs.

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 based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its two percent general partner interest and Incentive Distribution Rights (IDRs), and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The distribution to the General Partner illustrated below, other than in its capacity as a holder of 5,797,106 common units that are in excess of its aggregate two percent general partner interest, represents the IDRs.

		Marginal Percentage Interest in Distribution	
	Total Quarterly Distribution Per Unit Target Amount	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%

2013 Fourth Quarter Cash Distribution

On January 16, 2014, the board of directors of our General Partner declared the Partnership's fourth quarter 2013 cash distribution in the amount of $0.81 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2014 to unitholders of record as of January 28, 2014, totaled $52 million and was paid in the following manner: $51 million to common unitholders (including $5 million to the General Partner as holder of 5,797,106 common units and $9 million to TransCanada as holder of 11,287,725 common units) and $1 million to the General Partner in respect of its two percent general partner interest. The fourth quarter 2013 cash distribution represents an annual cash distribution of $3.24 per common unit.

Cash Distribution Policies of GTN, Northern Border, Bison and Great Lakes

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. GTN, Northern Border, Bison and Great Lakes' respective management committees determine the amounts and timing of cash distributions, where the amounts of such distributions are based on available cash flow as determined by a prescribed formula. Any changes to, or suspension of, GTN, Northern Border, Bison and Great Lakes' cash distribution policy requires the unanimous approval of their respective management committee.

GTN and Bison's distribution policies are to distribute 100 percent of distributable cash flow based on earnings before depreciation and amortization less allowance for funds used during construction (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.

Northern Border's distribution policy is to distribute 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 is to distribute 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.

Cash From Our Pipeline Systems

GTN declared its fourth quarter 2013 distribution of $28 million on January 9, 2014, of which the Partnership received its 70 percent share or $20 million. The distribution was paid on February 3, 2014.

Northern Border declared its fourth quarter 2013 distribution of $43 million on February 3, 2014, of which the Partnership received its 50 percent share or $21 million. The distribution was paid on February 3, 2014.

Bison declared its fourth quarter 2013 distribution of $17 million on January 9, 2014, of which the Partnership received its 70 percent share or $12 million. The distribution was paid on February 3, 2014.

Great Lakes declared its fourth quarter 2013 distribution of $12 million on January 9, 2014, of which the Partnership received its 46.45 percent share or $5 million. The distribution was paid on February 3, 2014.

Investing Activities for our Pipeline Systems

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)*	**2013[(a)]**	2012[(a)]	2011[(a)]
Maintenance	**22**	30	25
Growth	**3**	7	40
	25	37	65

[(a)] Financial information was recast to consolidate GTN and Bison for all periods presented.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012
Maintenance capital spending decreased $8 million to $22 million in 2013 compared to 2012. This decrease was primarily due to lower compressor station maintenance costs on GTN's pipeline system and lower compressor engine overhauls on Northern Border's pipeline system.

Growth capital spending decreased $4 million to $3 million in 2013 compared to 2012. This decrease was primarily due to the lower costs incurred in 2013 as a result of the completion of the Bison pipeline in 2012.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011
Maintenance capital spending increased $5 million to $30 million in 2012 compared to 2011. This increase was primarily due to compressor engine overhauls on Northern Border's pipeline system and higher compressor station maintenance and pipeline integrity program costs on GTN's pipeline system, partially offset by lower pipeline integrity program costs on Great Lakes' pipeline system.

Growth capital spending decreased $33 million to $7 million in 2012 compared to 2011. This decrease was primarily due to the higher costs incurred in 2011 related to the completion of the Bison pipeline and the Princeton Lateral Project on the Northern Border pipeline system.

Other Investing Activities
In 2014, our pipeline systems expect to invest approximately $34 million in maintenance of existing facilities and approximately $22 million in growth projects, of which the Partnership's share would be $19 million and $16 million, respectively.

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. The following summarizes the

Partnership's and our pipeline systems' accounting policies and estimates, and should be read in conjunction with Note 2 of the Partnership's Financial Statements included elsewhere in this report.

We account for our investments in Northern Border and Great Lakes using the equity method of accounting. The equity method of accounting is appropriate where the investor does not control an investee, but rather is able to exercise significant influence over the operating and financial policies of an investee. We are able to exercise significant influence over our investments in Northern Border and Great Lakes because of our ownership interests and our representation on their management committees.

We account for our investments in GTN, Bison, North Baja and Tuscarora using the consolidation method, as we are able to exercise control over these investments because of our ownership interests and our representation on their management committees.

Regulation

Our pipeline systems' accounting policies conform to *Accounting Standards Codification (ASC) 980 – Regulated Operations*. 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 ratemaking 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 ratemaking 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.

As of December 31, 2013, Northern Border reflected regulatory assets of $30 million on its balance sheet (2012 – $28 million). Northern Border also has regulatory liabilities of $17 million as of December 31, 2013 (2012 – $15 million).

As of December 31, 2013 and 2012, Great Lakes did not have any regulatory assets or liabilities recorded on its balance sheet.

The Partnership had no material regulatory assets as of December 31, 2013 and 2012. As of December 31, 2013, the Partnership had regulatory liabilities of $22 million mostly relating to GTN (2012 – $20 million).

Impairment of Equity Investments, Goodwill and Long-Lived Assets

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 also perform this evaluation every reporting period for each investment for which the carrying value has exceeded the fair value in the prior period. 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.

As of December 31, 2013, no impairment charge has been recorded related to our equity investments in Northern Border and Great Lakes. However, if our assumptions change significantly, our requirement to record an impairment charge could change.

Due to the challenging market conditions that continued to impact Great Lakes in 2013, we conducted a review of the carrying value of our equity investment in Great Lakes. We determined that the fair value exceeded the carrying value. Our assumptions related to the estimated fair value of our equity investment in Great Lakes could be negatively impacted by near and long-term conditions including weather and other demand drivers, North American natural gas production in the major producing basins, natural gas prices and natural gas storage market conditions. There is a risk that adverse changes in these key assumptions could result in a future impairment of the carrying value of our equity investment in Great Lakes which was $672 million as of December 31, 2013 (2012 – $677 million).

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 assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we do not conclude that it is more likely than not that the fair value of the reporting unit is greater than the carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit, including its goodwill, to its book value. If the fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value calculated in the first step. If the goodwill's carrying value exceeds its implied fair value we record an impairment charge.

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

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

At December 31, 2013 and 2012, we had $130 million of goodwill recorded on our consolidated balance sheet related to the North Baja and Tuscarora acquisitions. No impairment of goodwill existed at December 31, 2013.

Long-Lived Assets

We assess our long-lived assets for impairment based on *ASC 360-10-35 Property, Plant, and Equipment – Overall – Subsequent Measurement* whenever 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.

Depreciation

Depreciation expense in 2013 was $86 million. Depreciation of plant, property and equipment with a net book value of $2,042 million as of December 31, 2013, is provided on a straight-line composite basis over the assets' estimated useful lives. We estimate their useful lives based on third-party engineering studies, experience and industry practice. When changes to the estimated useful lives occur, the change is applied prospectively over the remaining expected useful life, which would result in a change to the depreciation expense in future periods. Pipeline facilities and compression equipment have an estimated useful life of 20 to 77 years and metering and other equipment ranges from 5 to 77 years. Changes in the assumptions used for the estimation of useful lives could result in material changes to depreciation expense in future periods.

Contingencies

Our pipeline systems' accounting for contingencies covers a variety of business activities, including contingencies for 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 pipeline systems' estimates resulting in an impact, positive or negative, on earnings and cash flow.

CONTINGENCIES

Legal

Various legal actions or governmental proceedings involving our pipeline systems that have arisen in the ordinary course of business are pending. Our pipeline systems believe that the resolution of these issues will not have a material adverse impact on their results of operations or financial position. Please read Item 3. "Legal Proceedings" for additional information.

Environmental

We believe that our pipeline systems are in substantial compliance with applicable environmental laws and regulations. Please read Item 1. "Business – Government Regulation" for additional information.

Greenhouse Gas Regulation

The outlook of new or proposed federal and state legislation and regulations to reduce GHG emissions is not yet certain. Nevertheless, we expect that some of our pipeline systems or assets could be affected either directly or indirectly by federal, state or local GHG emission legislation or regulations. Due to the speculative outlook regarding the details of future GHG restrictions and compliance mechanisms, we cannot estimate the potential effect of new or proposed GHG legislation or regulations on our operations, financial condition or consolidated results of operations. It is reasonably likely, however, that such legislation or regulations could materially increase our operating costs, including our cost of environmental compliance by requiring us to install additional equipment and potentially purchase emission allowances or offset credits. The regulation or restriction of GHG emissions could also result in changes to the consumption and demand for natural gas. This could have either positive or adverse effects on our pipeline systems, our financial position, results of operations and future prospects.

RELATED PARTY TRANSACTIONS

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts, which are provided at both discounted and maximum recourse rates. The contracts are on the same terms as would be available to other shippers.

Please read Item 13. "Certain Relationships and Related Transactions, and Director Independence" and Item 15. "Exhibits and Financial Statement Schedules" Note 16 "RELATED PARTY TRANSACTIONS" 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.

As of December 31, 2013, the Partnership's interest rate exposure results from our Senior Credit Facility and Term Loan Facility under which $730 million (2012 – $312 million), or 46 percent (2012 – 31 percent) of our outstanding debt was subject to variability in LIBOR interest rates. As of December 31, 2013, the variable interest rate exposure related to $150 million of the $500 million Term Loan Facility was hedged by fixed interest rate swap arrangements. If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2013, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately $7 million.

As of December 31, 2013, $62 million, or 15 percent of Northern Border's outstanding debt was at floating rates (2012 – $123 million or 26 percent). If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2013, Northern Border's annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately $1 million.

GTN, Great Lakes and Tuscarora utilize fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates. Interest rate risk does not apply to Bison and North Baja, as they currently do not have any debt.

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

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

The Partnership and our pipeline systems enter into interest rate swaps and option agreements to mitigate the impact of changes in interest rates.

The Partnership hedged interest payments on $150 million of variable-rate Term Loan Facility with interest rate swaps effective September 3, 2013 and maturing July 1, 2018, at a weighted average fixed interest rate of 2.79 percent. At December 31, 2013, the fair value of the interest rate swaps accounted for as cash flow hedges was less than $1 million (both on a gross and net basis) (December 31, 2012 and 2011 – nil). In 2013, the Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges. The change in fair value of interest rate derivative instruments recognized in other comprehensive income was less than $1 million for the year ended December 31, 2013. In 2013, the net realized loss related to the interest rate swaps was $1 million and was included in financial charges and other (2012 – nil; 2011 – $14 million).

The Partnership has no master netting agreements, however, 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, 2013 and 2012.

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. Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consists primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 31, 2013, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2013, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $37 million (2012 – $59 million).

The Partnership and our pipeline systems have significant credit exposure to financial institutions as they provide committed credit lines and critical liquidity in the interest rate derivative market, as well as letters of credit to mitigate exposures to non-creditworthy parties. The Partnership closely monitors the creditworthiness of our counterparties, including financial institutions. Overall, we do not believe the Partnership and our pipeline systems have any significant concentrations of counterparty credit risk.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they become due. Our approach to managing liquidity risk is to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation. At December 31, 2013, the Partnership had a committed revolving bank line of $500 million maturing in 2017 and the outstanding balance on this facility was $380 million. In addition, at December 31, 2013, Northern Border had a committed revolving bank line of $200 million maturing in 2016 and $62 million was drawn.

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.

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 quarter ended December 31, 2013, there was no change in the Partnership's internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting. Effective January 1, 2014, our General Partner implemented an Enterprise Resource Planning (ERP) system, which had no impact on our internal control over financial reporting at December 31, 2013. As a result of the ERP system, certain processes supporting our General Partner's internal control over financial reporting are expected to change in 2014. Our General Partner will continue to monitor these processes going forward.

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 Securities Exchange Act of 1934. 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 1992 by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment according to the above criteria, management has concluded that our internal control over financial reporting was effective as of December 31, 2013 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. There were no material weaknesses.

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 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. Each director holds office for a one-year term or until his or her successor is earlier appointed. All officers of the General Partner serve at the discretion of the board of directors of the General Partner which is a wholly-owned subsidiary of TransCanada.

Name	Age	Position with General Partner
Karl Johannson	53	Chair and Director
Steven D. Becker	63	President, Principal Executive Officer and Director
Jack F. Jenkins-Stark	63	Independent Director
Malyn K. Malquist	61	Independent Director
Walentin (Val) Mirosh	68	Independent Director
James M. Baggs	52	Director
Kristine L. Delkus	56	Director
Stuart P. Kampel	45	Vice-President and General Manager
Sandra P. Ryan-Robinson	51	Controller, Principal Financial Officer
Terry C. Ofremchuk	63	Vice-President, Taxation
Annie C. Belecki	42	Secretary
William C. Morris	51	Treasurer

Mr. Johannson was appointed a director and Chair of the Board of Directors of the General Partner in March 2013. Mr. Johannson's principal occupation is Executive Vice-President and President, Natural Gas Pipelines for TransCanada.

He is accountable for TransCanada's natural gas pipelines and regulated natural gas storage business in Canada, the U.S. and Mexico. Prior to November 2012, Mr. Johannson was Senior Vice-President, Canadian and Eastern U.S. Pipelines, a position he has held since January 2011. From January 2006 to December 2010, he held the position of Senior Vice-President, Canadian Power, where he was responsible for all activities relating to the day-to-day commercial management of TransCanada's Canadian power business. Mr. Johannson has extensive senior management experience in the pipelines and energy industries as a result of his service as an executive of TransCanada and its affiliates. His experience in his prior roles at TransCanada provides him with intimate knowledge of the Partnership, including its strategies, operations and markets. Mr. Johannson's industry knowledge, management experience and leadership skills are highly valuable in assessing our business strategies and accompanying risks.

Mr. Becker was appointed President and principal executive officer of the General Partner in August 2010. Mr. Becker also serves as a director of the General Partner, a position he has held since January 2007. Mr. Becker's principal occupation is Vice-President, Business Development, Pipelines Division of TransCanada, a position he has held since August 2010. Mr. Becker was Vice-President, Pipeline Development for TransCanada from June 2006 to August 2010. From April 2003 to June 2006, he was Vice-President, Gas Development of TransCanada. As the President of the General Partner and Vice-President, Business Development, Pipelines Division for TransCanada, Mr. Becker has intimate knowledge of the Partnership's pipeline operations, as well as a unique understanding of market factors and operational challenges and opportunities. Mr. Becker brings extensive project development and operational experience to the Board and his extensive experience in the natural gas industry enhances the knowledge of the Board in these areas of the industry. From his prior roles in finance, natural gas marketing, strategy and business development at TransCanada, Mr. Becker's breadth of executive experiences are applicable to many of the matters routinely facing the Partnership, which assists the Board in creating and executing the Partnership's strategy.

Mr. Jenkins-Stark was appointed a director of the General Partner in July 1999. Mr. Jenkins-Stark's principal occupation is Chief Financial Officer of Imergy Power Systems, formerly Deeya Energy, an energy storage systems company. Mr. Jenkins-Stark was Chief Financial Officer of BrightSource Energy Inc., a provider of technology for use in large-scale solar thermal power plans from May 2007 to November 2013. Mr. Jenkins-Stark was Chief Financial Officer of Silicon Valley Bancshares (offering financial products and services, including commercial, investment, merchant, private banking and private equity services) from April 2004 to May 2007. Through his current and prior roles as chief financial officer of numerous companies, Mr. Jenkins-Stark brings valuable financial expertise and management experience, including extensive knowledge regarding financial operations, investor relations, energy risk management, regulatory affairs and knowledge of the natural gas industry. Mr. Jenkin-Stark's prior service on the audit committee of the board of directors of another company further enhances his qualifications to serve as a member of our Board and our Audit Committee. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis.

Mr. Malquist was appointed a director of the General Partner in 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 currently serves on the Board of Directors of Headwaters Incorporated, an NYSE-listed company that provides products, technologies and services in the light building products, heavy construction materials and energy industries. From May 2006 to March 2009, Mr. Malquist served as Executive Vice-President of Avista Corporation (Avista), (energy production, transmission and distribution company). He also served as Chief Financial Officer of Avista from November 2002 to September 2008, Treasurer from February 2004 to January 2006 and Senior Vice-President from September 2002 to May 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 includes 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 the Partnership.

Mr. Mirosh was appointed a director of the General Partner in 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 (a commodity chemicals and plastics company). From July 2003 to April 2008, Mr. Mirosh was President of Olefins and Feedstocks, a division of NOVA Chemicals Corporation. Mr. Mirosh is also a director of Superior Plus Income Fund (energy services, specialty chemicals and construction products distribution) and 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, complemented by an engineering and legal educational background, enable Mr. Mirosh to provide the Board of Directors and Audit Committee with executive counsel on a full range of business, financial, technical and professional matters.

Mr. Baggs was appointed a director of the General Partner in March 2010. Mr. Baggs' principal occupation is Senior Vice-President, Operations and Engineering, Operations and Major Projects Division for TransCanada, a position he has held since June 2012. From 2008 to 2012, Mr. Baggs was Vice-President, Operations and Engineering for TransCanada. From 2006 to 2008, Mr. Baggs was Vice-President, Field Operations and Engineering for TransCanada. In his position as Senior Vice-President, Operations and Engineering at TransCanada, Mr. Baggs has unique insight into our operational challenges and opportunities. With an extensive career focused on providing construction, design, operations, maintenance and commissioning experience in various industries, Mr. Baggs contributes a broad-based understanding of the oil and gas industry and of complex operational and safety matters. Mr. Baggs' service on the board of directors of other energy services companies further enhances his qualifications to serve as a member of our Board.

Ms. Delkus was appointed a director of the General Partner in November 2003. Ms. Delkus' principal occupation is Senior Vice-President, Pipelines Law and Regulatory Affairs, Corporate Services Division of TransCanada, a position she has held since July 2012. As Senior Vice President, Pipelines Law and Regulatory Affairs, Ms. Delkus is responsible for, and has intimate knowledge of, the legal aspects of all regulatory and commercial matters for TransCanada's pipeline business in Canada and the U.S. Ms. Delkus' experience and industry knowledge, complemented by an extensive legal career, enable her to provide the Board with executive counsel on the full range of business, regulatory, legal and professional matters.

Mr. Kampel was appointed Vice-President and General Manager for the General Partner in July 2011. This is Mr. Kampel's principal occupation. Previously, he was Vice-President, Business Development for the General Partner. Mr. Kampel is also Director, Pipeline Development at TransCanada, a position he has held since December 2003. As Director, Pipeline Development he is responsible for identifying and pursuing natural gas pipeline and other related energy investment opportunities in the United States. Previously, his responsibilities included pursuing investment opportunities in Mexico.

Ms. Ryan-Robinson was appointed Controller and Principal Financial Officer of the General Partner in September 2011. Her principal occupation is Director of Pipeline Accounting for TransCanada. From April 2007 to April 2011, Ms. Ryan-Robinson was Manager, Accounting Research & Projects for TransCanada and from August 2003 to April 2007, she was Project Manager, Regulatory Services for TransCanada.

Mr. Ofremchuk was appointed Vice-President, Taxation of the General Partner in July 2007. Mr. Ofremchuk's principal occupation is Director, Taxation of TransCanada, a position he has held since December 2011. Prior to this position Mr. Ofremchuk was a Manager, Corporate Taxation of TransCanada, a position he held since October 1997.

Ms. Belecki was appointed Secretary of the General Partner in April 2012. Ms. Belecki's principal occupation is Associate General Counsel, Corporate and Securities in the Corporate Secretarial Group of TransCanada, a position she has held since March 2012. Prior to this, Ms. Belecki was Senior Legal Counsel, Corporate and Securities of TransCanada, a position she had held since September 2006.

Mr. Morris was appointed Treasurer of the General Partner in December 2012. Mr. Morris' principal occupation is Director, Corporate Finance of TransCanada, a position he has held since November 2012. From 2001 to 2012 Mr. Morris was Director of Risk Management for TransCanada and Manager, Risk Management for TransCanada for the previous five years.

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. This certification was provided to the NYSE on March 21, 2013.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the General Partner has determined that Malyn Malquist and Jack Jenkins-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 Jenkins-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, as employees of TransCanada, are subject to TransCanada's Code of Business Ethics (COBE) which has been adopted by our General Partner. Our COBE is published on our website at www.tcpipelineslp.com. If any substantive amendments are made to the code 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 committee are Malyn Malquist, as Chair, Jack Jenkins-Stark and Walentin (Val) Mirosh. All members of the Audit Committee meet the criteria for independence as set forth under the rules of the SEC and those of the NYSE. 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 able to read and understand fundamental financial statements, including a company's balance sheet, income statement and cash flow statement.

The Audit Committee has adopted a charter which specifically provides that it is responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants engaged in preparing and issuing the Partnership's audit report, that the 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 committee has adopted TransCanada'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.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of the General Partner meet at regularly scheduled executive sessions without management. Malyn Malquist 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., 717 Texas Street, Suite 2400, Houston, TX 77002, or via fax at 1.508.871.7047.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, as amended, requires the General Partner's directors and executive officers, and persons who beneficially own more than ten percent of the common units, to file reports of ownership and changes in ownership with the SEC and to furnish us with copies of all such reports. Based solely upon a review of the copies of the reports received by us, we believe that all such filing requirements were satisfied during 2013.

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 TransCanada.

The compensation policies and philosophy of TransCanada govern the types and amount of compensation granted to each of the named executive officers. Since these policies and philosophy are those of TransCanada, we refer you to a discussion of those items as set forth in the Executive Compensation section of the TransCanada "Management Information Circular" on the TransCanada website at www.tcpipelineslp.com. The TransCanada "Management Information Circular" is prepared by TransCanada 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 the total amount we are charged for managerial, administrative and operational support provided by TransCanada and its affiliates, including our

General Partner. The Board specifically approves the allocation of the salary of the President and Principal Executive Officer, the Controller and Principal Financial Officer and the Vice-President and General Manager to the Partnership on an annual basis. Please read Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information regarding this arrangement.

In addition to base salary, we also reimburse our General Partner for certain benefit and incentive compensation expenses related to the officers of our General Partner and employees of TransCanada who perform services on our behalf. The base salaries that are allocable to us vary for each officer or employee performing services on our behalf and are based on the 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 TransCanada and its other affiliates. We are allocated and reimburse the General Partner for each officer's salary expense. Other benefit and incentive compensation expenses related to our officers are reimbursed to the General Partner based upon an agreed upon calculation.

The following table summarizes the salary allocated to, and paid by, us in 2013, 2012 and 2011 for our President and Principal Executive Officer, Controller and Principal Financial Officer and other executive officers of our General Partner for whom salaries and benefits of more than $100,000 were allocated to us.

Summary Compensation Table

		Compensation Allocated to the Partnership				
Name and Principal Position	Year	Base Salary	Benefits[a][b]	Incentive Compensation[a][c]	Approximate Percentage of Time Devoted to the Partnership	Total Compensation
Steven D. Becker	**2013**	**70,250**	**20,373**	**38,638**	**30%**	**129,261**
President and Principal	2012	72,493	18,848	37,697	30%	129,038
Executive Officer	2011	103,905	27,015	54,031	30%	184,951
Sandra P. Ryan-Robinson[d]	**2013**	**65,148**	**18,893**	**35,831**	**35%**	**119,872**
Controller and Principal	2012	62,734	16,311	32,622	35%	111,667
Financial Officer	2011	21,662	5,632	11,264	40%	38,558
Stuart P. Kampel[e]	**2013**	**116,246**	**33,711**	**63,935**	**50%**	**213,892**
Vice-President and General	2012	168,101	43,706	87,412	80%	299,219
Manager	2011	95,752	24,895	49,791	30%	170,438
Terry C. Ofremchuk	**2013**	**89,420**	**25,932**	**49,181**	**45%**	**164,533**
Vice-President, Taxation	2012	89,632	23,204	46,609	45%	159,445
	2011	81,012	21,063	42,126	45%	144,201
William C. Morris[f]	**2013**	**97,992**	**28,418**	**53,896**	**45%**	**180,306**
Treasurer	2012	7,396	1,923	3,846	45%	13,165
	2011	–	–	–	–	–

(a) We reimburse our General Partner for benefit and incentive compensation expenses based on a set formula. These expenses include employment-related expenses, including TransCanada's restricted stock unit and stock option awards, retirement plans, health and welfare plans, employer-related payroll taxes, matching contributions made under TransCanada's employee savings plan, and premiums for health and life insurance.

(b) The benefit reimbursement is determined monthly and calculated based on total monthly base salary allocated to us multiplied by a factor of 0.29 for benefits in 2013 (2012 – factor of 0.26; 2011 – factor of 0.26).

[c] The incentive compensation reimbursement is determined monthly and calculated based on total monthly salary allocated to us multiplied by a factor of 0.55 for incentive compensation in 2013 (2012 – factor of 0.52; 2011 – factor of 0.52).

[d] 2011 figures for Ms. Ryan-Robinson relate to the period from September 2011 to December 2011.

[e] 2012 includes a full year of Mr. Kampel's responsibilities as Vice-President and General Manager for the Partnership.

[f] Appointed as Treasurer in December 2012. 2012 figures for Mr. Morris relate to December 2012.

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:
Steven D. Becker
James M. Baggs
Kristine L. Delkus
Jack F. Jenkins-Stark
Karl R. Johannson
Malyn K. Malquist
Walentin (Val) Mirosh

Independent Director Compensation[a]

For the year ended December 31, 2013 *(in dollars)*	Earned or Paid in Cash[b]	Unit Awards[c]	All Other Compensation[d]	Total
Malyn K. Malquist	61,250	69,250	11,212	141,712
Jack F. Jenkins-Stark[e]	76,750	49,000	35,906	161,656
Walentin (Val) Mirosh	69,500	49,000	20,357	138,857

[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 Karl R. Johannson, Steven D. Becker, Kristine L. Delkus and James M. Baggs. 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] Pursuant to the Deferred Share Unit Plan for Non-Employee Directors (DSU Plan), Malyn K. Malquist elected to receive 50 percent of his Board and committee attendance fees and committee chair retainer fees ($20,250) in DSUs. Due to this election, 418 DSUs were credited to Mr. Malquist's account in 2013, all of which were outstanding at December 31, 2013. Mr. Jenkins-Stark and Mr. Mirosh elected to receive their fees in cash.

[c] Amounts presented reflect the compensation expense recognized related to the DSUs granted during 2013 under the DSU Plan. On January 17, 2013, each independent director was granted 1,160 DSUs. All of the DSUs granted to Mr. Malquist, Mr. Jenkins-Stark and Mr. Mirosh were outstanding at December 31, 2013.

At December 31, 2013, Malyn K. Malquist, Jack F. Jenkins-Stark and Walentin (Val) Mirosh held 3,906, 11,766 and 6,670 DSUs, respectively. The fair value of DSUs held by Mr. Malquist, Mr. Jenkins-Stark and Mr. Mirosh at December 31, 2013 was $189,183, $569,837 and $323,075, respectively.

[d] Amounts presented reflect DSUs credited to each independent director's account equal to the distributions payable on the DSUs previously granted or credited. In this regard, Malyn K. Malquist was credited 237 DSUs, Jack F. Jenkins-Stark was credited 759 DSUs and Walentin (Val) Mirosh was credited 430 DSUs. All DSUs credited during 2013 were outstanding at December 31, 2013.

[e] Lead Director and Chair of the Conflicts Committee.

Cash Compensation

In 2013, each director who was not an employee of TransCanada, the General Partner or its affiliates (independent director) was entitled to a directors' retainer fee of $90,000 per annum, of which $49,000 was automatically granted in DSUs (see DSUs section below). The independent director appointed as Lead 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 $10,000 and $12,000 per annum, respectively. Each independent director was also paid a fee of $1,500 for attendance at each meeting of the board of directors and a fee of $1,500 for attendance at each meeting of a committee of the board. 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 fees in the form of DSUs pursuant to the DSU Plan. On October 24, 2013, the board approved an increase in the independent directors' 2014 annual retainer fee of $10,000 per annum, of which $6,000 will be granted in DSUs. As a result, commencing January 1, 2014, the retainer fee will be $100,000 per annum, of which $55,000 will automatically be granted in DSUs.

Deferred Share Units

The DSU Plan was established in 2007 with the first grant occurring in January 2008. In 2013, as part of the retainer fee, each independent director received an annual grant of DSUs with a value of $49,000.

At the time of grant, the value of a DSU is equal to the market value of a common unit at the time the independent director is credited with the units. The value of a DSU when redeemed is equivalent to the market value of a common unit 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 at their option. DSUs redeemed for common units would be purchased by the Partnership in the open market.

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

The following table sets forth information as of February 20, 2014 regarding the (i) beneficial ownership of our common units and shares of TransCanada 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 5 percent of our common units.

	Amount and Nature of Beneficial Ownership			
	TC PipeLines, LP		TransCanada Corporation	
Name and Business Address	Number of Units[a]	Percent of Class[b]	Common Shares	Percent of Class
TransCan Northern Ltd[c] 450-1st Street SW Calgary, Alberta T2P 5H1	11,287,725	18.1	–	–
TC Pipelines GP, Inc.[d] 450-1st Street SW Calgary, Alberta T2P 5H1	5,797,106	9.3	–	–
OppenheimerFunds, Inc.[e] Two World Financial Center 225 Liberty Street New York, NY 10281	9,348,661	15.0	–	–
Malyn K. Malquist[f]	4,973	*	–	–
Jack F. Jenkins-Stark[g]	13,968	*	–	–
Walentin (Val) Mirosh[h]	6,785	*	995	*
Karl R. Johannson[i]	–	–	160,001	*
Steven D. Becker[j]	–	–	76,166	*
Kristine L. Delkus[k]	–	–	91,088	*
James M. Baggs[l]	–	–	75,520	*
Sandra P. Ryan-Robinson[m]	–	–	611	*
Directors and Executive officers as a Group[n] (12 people)	25,726	*	433,051	*

[a] A total of 62,327,766 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 TransCanada.

[d] TC PipeLines GP, Inc. is a wholly-owned indirect subsidiary of TransCanada and also owns an aggregate two percent general partner interest of the Partnership.

[e] Based on a Schedule 13G/A filed with the SEC on February 7, 2014 by OppenheimerFunds, Inc. In this Schedule 13G/A, OppenheimerFunds, Inc. reported that it has shared power to vote 9,348,661 common units and shared power to dispose of all 9,348,661 common units.

[f] Includes 3,973 DSUs and 1,000 common units.

(g) Includes 11,968 DSUs and 2,000 common units held by the Jenkins-Stark Family Trust dated June 16, 1995.

(h) Includes 6,785 DSUs.

(i) Includes 137,594 options exercisable within 60 days for TransCanada common shares and 22,407 TransCanada common shares held in his Employee Savings Plan account.

(j) Includes 52,284 options exercisable within 60 days for TransCanada common shares, 18,719 TransCanada common shares held directly and 5,163 TransCanada common shares held in his Employee Savings Plan account.

(k) Includes 75,987 options exercisable within 60 days for TransCanada common shares, 7,849 TransCanada common shares held directly and 7,252 TransCanada common shares held in her Employee Savings Plan account.

(l) Includes 69,230 options exercisable within 60 days for TransCanada common shares, 2,864 TransCanada common shares held in a RRSP account, 2,694 TransCanada common shares held in his Employee Savings Plan account and 732 TransCanada common shares held in his spouse's Employee Savings Plan account.

(m) Includes 611 TransCanada common shares held in her Employee Savings Plan account.

(n) Includes 335,095 options exercisable within 60 days for TransCanada common shares, 22,726 DSUs, 12,542 common shares of TransCanada owned by immediate family members of which beneficial ownership of no common shares is disclaimed and 56,714 common shares held in the TransCanada Employee Savings Plan.

* Less than one percent.

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

As of February 28, 2014, TransCanada owns 11,287,725 common units and the Partnership's General Partner owns 5,797,106 common units, representing an aggregate 26.9 percent limited partner interest in the Partnership. In addition, the General Partner owns an aggregate two percent general partner interest in the Partnership through which it manages and operates the Partnership. As a result, TransCanada's aggregate ownership interest in the Partnership is 28.9 percent by virtue of its indirect ownership of the General Partner and 26.9 percent aggregate limited partner interest.

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 TransCanada, 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 will generally make cash distributions of 98 percent to common unitholders, including our general partner and its affiliates as holders of an aggregate of 17,084,831 common units, and the remaining 2 percent to our General Partner
Payments to our General Partner and its affiliates	In addition, 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.

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 $3 million for the year ended December 31, 2013.

Operating Agreements with Our Pipeline Companies

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

Cash Management Programs

Effective October 1, 2013, GTN and Bison participate in the Partnership's cash management program. Prior to this, they were part of TransCanada's cash management program. Great Lakes has a cash management agreement with TransCanada whereby its funds are pooled with other TransCanada affiliates. The agreement gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for its operating needs.

Transportation Agreements

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts some of which are provided at discounted rates and some at maximum recourse rates. These contracts are on the same terms as would be available to other shippers. Great Lakes earned $68 million of transportation revenues under these contracts in 2013. This amount represents 55 percent of total revenues earned by Great Lakes in 2013. Great Lakes also earned $1 million in affiliated rental revenue in 2013.

Revenue from TransCanada and its affiliates of $32 million is included in the Partnership's equity earnings from Great Lakes in 2013. At December 31, 2013, $11 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates.

GTN and Bison Acquisitions

On July 1, 2013, we acquired an additional 45 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada. The total purchase price of the 2013 Acquisition was $1,050 million plus working capital adjustments of $17 million and Carty Lateral consideration of $25 million. With respect to the Carty Lateral, the Partnership accrued $25 million of additional consideration in accordance with the 2013 Acquisition. This amount is payable to a subsidiary of TransCanada and is included in accounts payable to affiliates as of December 31, 2013.

Other Agreements

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

Capital and operating costs charged to our pipeline systems for the years ended December 31, 2013, 2012 and 2011 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2013 and 2012 are summarized in the following tables:

Year ended December 31 *(millions of dollars)*	**2013**	2012	2011
Capital and operating costs charged by TransCanada's subsidiaries to:			
GTN[(a)(b)]	**28**	29	33
Northern Border[(a)]	**30**	31	29
Bison[(a)(b)]	**5**	6	11
Great Lakes[(a)]	**31**	33	31
North Baja	**4**	4	4
Tuscarora	**4**	4	5
Impact on the Partnership's net income attributable to controlling interests:			
GTN[(b)]	**19**	19	22
Northern Border	**14**	14	13
Bison[(b)]	**4**	4	4
Great Lakes	**14**	15	14
North Baja	**4**	4	4
Tuscarora	**4**	4	5

December 31 *(millions of dollars)*	**2013**	2012
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
GTN[(a)]	**3**	3
Northern Border[(a)]	**3**	4
Bison[(a)]	**–**	1
Great Lakes[(a)]	**3**	4
North Baja	**1**	1
Tuscarora	**–**	1

(a) Represents 100 percent of the costs.

(b) Financial information was recast to consolidate GTN and Bison for all periods presented.

Bison's former parent made an equity contribution to Bison of $18 million in the second quarter of 2013. This amount represents former parent's 75 percent share of a $24 million cash call from Bison to repay inter-affiliate debt primarily related to pipeline construction costs, including reclamation and restoration work. In 2011, Bison's former parent made an equity contribution to Bison of $305 million related to pipeline system construction costs.

Relationship with our General Partner and TransCanada 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 TransCanada, 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 Item 10. "Directors, Executive Officers and Corporate Governance" for additional information.

Director Independence

Please read 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)*	**2013**[(a)]	2012[(a)]
Audit Fees[(b)]	**1,018**	718
Audit Related Fees	**–**	–
Tax Fees[(c)]	**–**	–
All Other Fees	**–**	–
Total	**1,018**	718

(a) The information was recast to consolidate GTN and Bison for all periods presented.

(b) $294 thousand of the 2013 Audit Fees relate to equity and debt financing in connection with the 2013 Acquisition.

(c) The Partnership did not engage its external auditors for any tax or other services in 2013 or 2012.

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 principal accountant is engaged each year for annual audit and any non-audit services, these services and fees are reviewed and approved by our Audit Committee.

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 Membership Interest by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership dated May 19, 2009 (Incorporated by reference to Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on May 20, 2009).
*2.1.1	First Amendment to Agreement for Purchase And Sale of Membership Interest by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership dated June 29, 2010 (Incorporated by reference to Exhibit 2.1 to TC PipeLines, LP's Form 10-Q filed on July 29, 2010).
*2.2	Agreement for Purchase and Sale of Membership Interest dated as of April 26, 2011 between TransCanada American Investments Ltd., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Incorporated by reference to Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on April 27, 2011)
*2.3	Agreement for Purchase and Sale of Membership Interest dated as of April 26, 2011 between TC Continental Pipeline Holdings Inc., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Incorporated by reference to Exhibit 2.2 to TC PipeLines, LP's Form 8-K filed on April 27, 2011).
*2.4	Agreement for purchase and sale of membership interest dated as of May 15, 2013 between TransCanada American Investments Ltd., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on May 15, 2013).
*2.5	Agreement for purchase and sale of membership interest dated as of May 15, 2013 between TC Continental Pipeline Holdings Inc., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Exhibit 2.2 to TC PipeLines, LP's Form 8-K filed on May 15, 2013).
*3.1	Second Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated July 1, 2009 (Incorporated by reference to Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*3.2	Certificate of Limited Partnership of TC PipeLines, LP (Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, filed on December 30, 1998).
*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).
*10.1	Amended and Restated Agreement of Limited Partnership of Great Lakes Gas Transmission Limited Partnership between TransCanada GL, Inc., TC GL Intermediate Limited Partnership and Great Lakes Gas Transmission Company dated February 22, 2007 (Incorporated by reference to Exhibit 10.9 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007).
*10.1.1	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Great Lakes Gas Transmission Partnership between TransCanada GL, Inc., TC GL Intermediate Limited Partnership and Great Lakes Gas Transmission Company dated October 25, 2010 (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 19, 2011).

No.	Description
*10.2	Operating Agreement between Great Lakes Gas Transmission Limited Partnership and Great Lakes Gas Transmission Company dated April 5, 1990 (Incorporated by reference to Exhibit 10.10 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007).
*10.3	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company by and between Northern Border Intermediate Limited Partnership and TC Pipelines Intermediate Limited Partnership dated April 6, 2006 (Incorporated by reference to Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006).
*10.4	Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. dated April 6, 2006 (Incorporated by reference to Exhibit 10.2 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006).
*10.4.1	Amendment No.1 to Northern Border Pipeline Company Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated April 22, 2008 (Incorporated by reference to Exhibit 10.9.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.4.2	Second Amendment of Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated February 10, 2010 (Incorporated by reference to Exhibit 10.9.2 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*10.5	Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated December 19, 2006 (Incorporated by reference to Exhibit 10.11 to TC PipeLines, LP's Form 10-K filed on March 2, 2007).
*10.5.1	First Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated June 21, 2007 (Incorporated by reference to Exhibit 10.10.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.5.2	Second Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated December 31, 2007 (Incorporated by reference to Exhibit 10.10.2 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.5.3	Third Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2008 (Incorporated by reference to Exhibit 10.10.3 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.5.4	Fourth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2009 (Incorporated by reference to Exhibit 10.10.4 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*10.5.5	Fifth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2010 (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 27, 2011).
*10.6	Management Services Agreement by and between Gas Transmission Service Company, LLC (formally PG&E Gas Transmission Service Company, LLC) and North Baja Pipeline, LLC dated January 1, 2002 (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 4, 2009).

No.	Description
*10.7	Amended and Restated Revolving Credit and Term Loan Agreement, dated February 13, 2007, among TC PipeLines, LP, the lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents, BMO Capital Markets Financing Inc. and the Royal Bank of Scotland PLC, as Co-Syndication Agents, Deutsche Bank AG New York Branch and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Managing Agents, and SunTrust Capital Markets, Inc. as Arranger and Book Manager (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on October 29, 2010).
*10.8	Contribution, Conveyance and Assumption Agreement among TC PipeLines, LP and certain other parties dated May 28, 1999 (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-K filed on March 28, 2000).
*10.9	Form of Conveyance, Contribution and Assumption Agreement among Northern Plains Natural Gas Company, Northwest Border Pipeline Company, Pan Border Gas Company, Northern Border Partners, L.P., and Northern Border Intermediate Limited Partnership (Incorporated by reference to Exhibit 10.16 to Northern Border Pipeline Company's Form S-1 Registration Statement filed on July 16, 1993 (Registration No. 33-66158)).
*10.10	Form of Contribution, Conveyance and Assumption Agreement by and among TransCanada Border Pipeline Ltd., TransCan Northern Ltd., TransCanada PipeLines Limited, TC PipeLines, L.P., TC PipeLines Intermediate Limited Partnership and TC PipeLines GP, Inc. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form S-1/A filed on May 3, 1999).
*10.11	Membership Interest Purchase Agreement by and between Northern Border Pipeline Company and TransCanada Pipeline USA Ltd. dated August 28, 2008, (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on November 3, 2008).
*10.12	Common Unit Purchase Agreement by and between TC PipeLines, LP and TransCan Northern Ltd. dated July 1, 2009 (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*10.13	Exchange Agreement by and between TC PipeLines, LP and TC PipeLines GP, Inc. dated July 1, 2009 (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*10.14	First Amendment to Amended and Restated Revolving Credit and Term Loan Agreement, dated as of July 13, 2011, by and among TC PipeLines, LP, the Lenders, and SunTrust Bank, as administrative agent for the Lenders, including (as Exhibit A thereto) the Second Amended and Restated Revolving Credit and Term Loan Agreement dated as of July 13, 2011. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 19, 2011).
*10.15	First Amendment to Second Amended and Restated Revolving Credit and Term Loan Agreement, dated as of November 20, 2012, by and 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, 2013).
*10.16	Guaranty by TransCanada Pipeline USA Ltd. dated May 15, 2013 with respect to the obligations of TransCanada American Investments Ltd. (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on May 15, 2013).
*10.17	Guaranty by TransCanada Pipeline USA Ltd. dated May 15, 2013 with respect to the obligations of TC Continental Pipeline Holdings Inc. (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on May 15, 2013).

No.	Description
*10.18	Term Loan Agreement, dated as of July 1, 2013, between the Partnership and the lenders (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 3, 2013).
#10.19	TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2013), effective as of January 1, 2014, as amended on December 16, 2013.
12.1	Computation of Ratio of Earnings to Fixed Charges.
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.
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	Transportation Service Agreement FT9141 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 12, 2008. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008).
*99.2	Transportation Service Agreement FT9158 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 14, 2008. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008).
*99.3	Transportation Service Agreement FT11701 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 26, 2008. (Incorporated by reference to Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*99.4	Transportation Service Agreement IT11986 between Great Lakes Gas Transmission Limited Partnership and TransCanada Gas Storage USA Inc., dated February 27, 2009. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2009).
*99.5	Transportation Service Agreement FT16128 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011 (Incorporated by reference to Exhibit 99.11 to TC PipeLines, LP's Form 10-K filed on February 28, 2012).
*99.6	Transportation Service Agreement FT16129 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011 (Incorporated by reference to Exhibit 99.12 to TC PipeLines, LP's Form 10-K filed on February 28, 2012).
*99.7	Transportation Service Agreement FT16130 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011 (Incorporated by reference to Exhibit 99.13 to TC PipeLines, LP's Form 10-K filed on February 28, 2012).
*99.8	Transportation Service Agreement FT17189 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated February 6, 2012 (Incorporated by reference to Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed on April 30, 2012).

No.	Description
*99.9	Transportation Service Agreement FT17190 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated February 6, 2012 (Incorporated by reference to Exhibit 99.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2012).
*99.10	Transportation Service Agreement FT17193 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated February 6, 2012 (Incorporated by reference to Exhibit 99.3 to TC PipeLines, LP's Form 10-Q filed on April 30, 2012).
*99.11	Transportation Service Agreement FT17593 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated October 30, 2012. (Incorporated by reference to Exhibit 99.16 to TC PipeLines, LP's Form 10-K filed on February 28, 2013).
*99.12	Transportation Service Agreement FT17196 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated December 3, 2012. (Incorporated by reference to Exhibit 99.17 to TC PipeLines, LP's Form 10-K filed on February 28, 2013).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* 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 28th day of February 2014.

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

By: /s/ Steven D. Becker

Steven D. Becker
President
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ Sandra P. Ryan-Robinson

Sandra P. Ryan-Robinson
Controller
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/ Karl R. Johannson Karl R. Johannson	Chair	February 28, 2014
/s/ Steven D. Becker Steven D. Becker	President and Principal Executive Officer	February 28, 2014
/s/ Sandra P. Ryan-Robinson Sandra P. Ryan-Robinson	Controller and Principal Financial Officer	February 28, 2014
/s/ James M. Baggs James M. Baggs	Director	February 28, 2014
/s/ Kristine L. Delkus Kristine L. Delkus	Director	February 28, 2014
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 28, 2014
/s/ Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	February 28, 2014
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 28, 2014

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
TC PipeLines GP, Inc. General Partner of TC PipeLines, LP:

We have audited the accompanying consolidated balance sheets of TC PipeLines, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners' equity for each of the years in the three-year period ended December 31, 2013. We also have audited TC PipeLines, LP internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management of the General Partner of TC PipeLines, LP 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 these consolidated financial statements and an opinion on TC PipeLines, LP internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

A company'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 company'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 company; (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 company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company'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.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TC PipeLines, LP and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, TC PipeLines, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/s/ KPMG LLP

Houston, Texas
February 28, 2014

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2013**	2012[(a)]
Assets		
Current Assets		
Cash and cash equivalents	**25**	3
Demand loan receivable from affiliate (Note 16)	**–**	21
Accounts receivable and other (Note 19)	**37**	38
Inventories	**7**	7
	69	69
Investments in unconsolidated affiliates (Note 4)	**1,195**	1,189
Plant, property and equipment (Note 5)	**2,042**	2,111
Goodwill	**130**	130
Other assets	**7**	6
	3,443	3,505
Liabilities and Partners' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**19**	26
Accounts payable to affiliates (Note 16)	**29**	6
Accrued interest	**4**	2
Demand loan payable to affiliate (Note 16)	**–**	15
Current portion of long-term debt (Note 7)	**3**	3
	55	52
Long-term debt (Note 7)	**1,575**	1,010
Other liabilities (Note 8)	**24**	21
	1,654	1,083
Partners' Equity (Note 9)		
Common units	**1,322**	1,275
General partner	**28**	27
Accumulated other comprehensive loss (Note 10)	**(1)**	(1)
Controlling interests	**1,349**	1,301
Non-controlling interests	**440**	448
Equity of former parent of GTN and Bison	**–**	673
	1,789	2,422
	3,443	3,505

(a) Recast as discussed in Note 2 and Note 6.

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

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 (millions of dollars except per common unit amounts)	**2013[a]**	2012[a]	2011[a]
Transmission revenues	**341**	343	353
Equity earnings from unconsolidated affiliates (Note 4)	**67**	99	135
Operation and maintenance expenses	**(55)**	(57)	(61)
Property taxes	**(23)**	(25)	(23)
General and administrative	**(9)**	(6)	(9)
Depreciation	**(86)**	(85)	(87)
Financial charges and other (Note 11)	**(44)**	(40)	(46)
Income taxes (Note 2(k))	**–**	–	(12)
Net income	**191**	229	250
Net income attributable to non-controlling interests	**36**	37	34
Net income attributable to controlling interests	**155**	192	216
Net income attributable to controlling interests allocation (Note 12)			
Common units	**126**	134	154
General Partner	**3**	3	3
	129	137	157
Net income per common unit (Note 12) – basic and diluted	**$2.13**	$2.51	$3.02
Weighted average common units outstanding *(millions)* – basic and diluted	**58.9**	53.5	51.1
Common units outstanding, end of year *(millions)*	**62.3**	53.5	53.5

[a] Recast as discussed in Note 2 and Note 6.

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2013[a]**	2012[a]	2011[a]
Net income	**191**	229	250
Other comprehensive income			
Change in fair value of cash flow hedges (Note 18)	**–**	–	–
Reclassification to net income of gains and losses on cash flow hedges (Note 10)	**–**	–	14
	–	–	14
Total comprehensive income	**191**	229	264
Comprehensive income attributable to non-controlling interests	**36**	37	34
Comprehensive income attributable to controlling interests	**155**	192	230

[a] Recast as discussed in Note 2 and Note 6.

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

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2013[a]**	2012[a]	2011[a]
Cash Generated From Operations			
Net income	**191**	229	250
Depreciation	**86**	85	87
Amortization of debt issue costs (Note 11)	**1**	1	2
Equity allowance for funds used during construction	**–**	–	(2)
Deferred income taxes (Note 2(k))	**–**	–	6
Change in other long-term liabilities	**2**	–	(3)
Change in operating working capital (Note 14)	**(8)**	–	–
	272	315	340
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Great Lakes	**14**	17	13
Northern Border	**20**	24	24
Investment in Great Lakes (Note 4)	**(9)**	(9)	(9)
Investment in Northern Border (Note 4)	**(31)**	–	(55)
Acquisition of interests in each of GTN and Bison, net of cash acquired (Note 6)	**(921)**	–	(539)
Adjustment to the 2011 Acquisition (Note 6)	**1**	–	–
Capital expenditures	**(15)**	(36)	(163)
Change in affiliate demand loan receivable	**21**	20	4
	(920)	16	(725)
Financing Activities			
Distributions paid on common units (Note 13)	**(188)**	(169)	(155)
Distributions paid to non-controlling interests	**(52)**	(53)	(53)
Change in affiliate demand loan payable	**(15)**	–	–
Equity issuance, net (Note 9)	**381**	–	338
Long-term debt issued (Note 7)	**937**	8	1,038
Long-term debt repaid (Note 7)	**(372)**	(62)	(971)
Debt issue costs	**(2)**	–	(7)
Equity contribution from Bison's former parent (Note 16)	**18**	–	305
Distributions paid to former parent of GTN and Bison	**(37)**	(81)	(85)
	670	(357)	410
Increase/(decrease) in cash and cash equivalents	**22**	(26)	25
Cash and cash equivalents, beginning of year	**3**	29	4
Cash and cash equivalents, end of year	**25**	3	29
Interest payments made	**42**	42	31
Income taxes paid, net of refunds (Note 2(k))	**–**	–	6
Supplemental information about non-cash investing and financing activities			
Accrual for Carty Lateral consideration payment (Note 16)	**25**	–	–
Calpine receivable distributed	**–**	–	9
Interaffiliate account representing pension plan and other post-retirement benefits distributed	**–**	–	9

[a] Recast as discussed in Note 2 and Note 6.

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

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

Year ended December 31 (millions of dollars)	**2013**	2012	2011
Common Units			
Balance at beginning of year	**1,275**	1,307	1,105
Net income[a]	**152**	188	212
Net income attributed to GTN's and Bison's former parent[a]	**(26)**	(54)	(58)
Equity issuance, net (Note 9)	**373**	–	331
Distributions paid	**(184)**	(166)	(152)
Excess purchase price over net acquired assets (Note 6)	**(268)**	–	(131)
Adjustment to the 2011 Acquisition (Note 6)	**1**	–	–
Other	**(1)**	–	–
Balance at end of year	**1,322**	1,275	1,307
General Partner			
Balance at beginning of year	**27**	27	23
Net income[a]	**3**	4	4
Net income attributed to GTN's and Bison's former parent[a]	**–**	(1)	(1)
Equity issuance, net (Note 9)	**8**	–	7
Distributions paid	**(4)**	(3)	(3)
Excess purchase price over net acquired assets (Note 6)	**(6)**	–	(3)
Balance at end of year	**28**	27	27
Accumulated Other Comprehensive Loss[b]			
Balance at beginning of year	**(1)**	(1)	(15)
Other comprehensive income	**–**	–	14
Balance at end of year	**(1)**	(1)	(1)
Equity attributable to controlling interests[a]	**1,349**	1,301	1,333
Equity attributable to non-controlling interests[a]			
Balance at beginning of year	**448**	465	342
Net income	**36**	37	34
Distributions paid to non-controlling interests	**(52)**	(53)	(53)
Effect of conversion to an LLC by GTN and other (Note 2(k))	**–**	(1)	50
Equity contribution from Bison's former parent (Note 16)	**8**	–	92
Balance at end of year	**440**	448	465
Equity of former parent of GTN and Bison[a]			
Balance at beginning of year	**673**	698	799
Net income	**26**	55	59
Distribution paid related to equity of former parent of GTN and Bison	**(37)**	(81)	(85)
Effect of conversion to an LLC by GTN and other (Note 2(k))	**–**	1	119
Equity contribution from Bison's former parent (Note 16)	**10**	–	213
Former parent carrying amount of acquired entities	**(672)**	–	(407)
Balance at end of year	**–**	673	698
Total Equity[a]	**1,789**	2,422	2,496

[a] Recast as discussed in Note 2 and Note 6.

[b] Losses related to cash flow hedges reported in Accumulated Other Comprehensive Loss and expected to be reclassified to net income in the next 12 months are estimated to be less than $1 million. These estimates assume constant interest rates over time; however, the amounts reclassified will vary based on actual value of interest rates at the date of settlement.

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

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

The Partnership owns the following interests in natural gas pipeline systems:

Pipeline	Length	Description	Ownership
Gas Transmission Northwest LLC (GTN)	1,353 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. TransCanada owns the remaining 30 percent of GTN.	70 percent
Northern Border Pipeline Company (Northern Border)	1,408 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 Williston Basin and Rocky Mountain Basin. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50 percent
Bison Pipeline LLC (Bison)	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison was placed into service in January 2011 to transport natural gas from the Powder River Basin to Midwest markets. TransCanada owns the remaining 30 percent of Bison.	70 percent
Great Lakes Gas Transmission Limited Partnership (Great Lakes)	2,115 miles	Connects with the TransCanada 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. TransCanada owns the remaining 53.55 percent of Great Lakes.	46.45 percent
North Baja Pipeline, LLC (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. North Baja is a bi-directional pipeline.	100 percent
Tuscarora Gas Transmission Company (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

The Partnership is managed by its General Partner, TC PipeLines GP, Inc. (General Partner), an indirect wholly-owned subsidiary of TransCanada. The General Partner provides management and operating services for the Partnership and is reimbursed for its costs and expenses. In addition to its aggregate two percent general partner interest in the Partnership, the General Partner owns 5,797,106 common units, together with its general partner interest, representing an effective 11.1 percent interest in the Partnership at December 31, 2013. TransCanada also indirectly holds additional 11,287,725 common units representing a 17.8 percent limited partner interest in the Partnership for a total interest in the Partnership of 28.9 percent at December 31, 2013.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying financial statements and related notes have been prepared in accordance with United States generally accepted accounting principles (GAAP) and amounts are stated in U.S. dollars. The financial statements and notes present the financial position of the Partnership as of December 31, 2013 and 2012 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2013, 2012 and 2011.

(a) Basis of Presentation

The Partnership consolidates its investments in GTN, Bison, North Baja and Tuscarora, 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 Northern Border and Great Lakes, over which it is able to exercise significant influence.

On July 1, 2013, the Partnership acquired an additional 45 percent membership interest in each of GTN and Bison (the 2013 Acquisition) from subsidiaries of TransCanada. The 2013 Acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of GTN and Bison were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to consolidate GTN and Bison for all periods presented. Refer to Note 6 for additional disclosure regarding the 2013 Acquisition.

(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) Inventories

Inventories primarily consist of materials and supplies and are carried at the lower of weighted average cost or market.

(f) Plant, Property and Equipment

Plant, property 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 5 to 77 years. Depreciation is calculated on a straight-line composite basis over the assets' estimated useful lives. Repair and maintenance costs are expensed as incurred. Costs that are considered a betterment are capitalized.

An allowance for funds used during construction, using the rate of return on rate base approved by the Federal Energy Regulatory Commission (FERC), is capitalized and included in the cost of plant, property and equipment. Amounts included in construction work in progress are not amortized until transferred into service.

(g) Impairment of 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 also perform this evaluation every reporting period for each investment for which the carrying value has exceeded the fair value in the prior period. 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.

(h) Impairment of Long-lived Assets

The Partnership reviews long-lived assets, such as plant, property 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.

(i) Partners' Equity

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

(j) Revenue Recognition

Transmission revenues are recognized in the period in which the service is provided. When a rate case is pending final FERC approval, a portion of the revenue collected is subject to possible refund. As of December 31, 2013, 2012 and 2011, the Partnership has not recognized any transmission revenue that is subject to possible refund.

(k) Income Taxes

The Partnership is not subject to federal or state income tax. 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 income, is includable in the 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.

As a result of the recast of the Partnership's historical financial information (refer to Note 2 (a)), the Partnership included income taxes in its consolidated financial statements for the year ended December 31, 2011. Those income taxes relate to GTN for the periods prior to April 1, 2011. GTN is no longer subject to income taxes and settled all current and deferred income tax balances pursuant to GTN's tax-sharing agreement with TransCanada PipeLine USA Ltd. upon conversion to an LLC on April 1, 2011. GTN used the Asset and Liability method of accounting for income taxes for the periods prior to April 1, 2011.

(l) 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 on an annual basis for impairment or more frequently if any indicators of impairment are evident. The Partnership initially assesses qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired. If the Partnership does not conclude that it is more likely than not that fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded.

The Partnership accounts for business acquisitions between entities under common control using a method whereby the assets and liabilities of the acquired entities are recorded at TransCanada's carrying value and the Partnership's historical financial information is recast 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 to 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 to Partners' Equity.

(m) Fair Value Measurements

For cash and cash equivalents, demand loan receivable or payable to affiliate, 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 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. Considerable judgement is required in developing these estimates.

(n) 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). For all hedging relationships, the Partnership formally documents the hedging relationship and its risk management objective and strategy for undertaking the hedge, the hedging instrument, the hedged transaction, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. The Partnership also formally assesses, both at the inception of the hedging relationship and on an ongoing basis, whether the derivatives that are used in hedging relationships are highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that are designated and qualify as part of a cash flow hedging relationship, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

The Partnership discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting cash flows attributable to the hedged risk, the derivative expires or is sold, terminated, or exercised, the cash flow hedge is de-designated because a forecasted transaction is not probable of occurring, or management determines to remove the designation of the cash flow hedge.

In all situations in which hedge accounting is discontinued and the derivative remains outstanding, the Partnership continues to carry the derivative at its fair value on the balance sheet and recognizes any subsequent changes in its fair value in earnings. When it is probable that a forecasted transaction will not occur, the Partnership discontinues hedge accounting and recognizes immediately in earnings gains and losses that were accumulated in other comprehensive income related to the hedging relationship.

(o) 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 scope and timing of asset retirements related to natural gas pipelines is indeterminable. As a result, the Partnership has recorded no asset retirement obligations as of December 31, 2013 and 2012.

(p) 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 ratemaking 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. The Partnership had no material regulatory assets as of December 31, 2013 and 2012. Regulatory liabilities are included in other long-term liabilities (refer to Note 8). Allowance for funds used during construction is capitalized and included in plant, property and equipment.

(q) 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.

NOTE 3 CHANGES IN ACCOUNTING POLICIES FOR 2013

Balance Sheet Offsetting/Netting

Effective January 1, 2013, the Partnership adopted the Accounting Standards Update (ASU) on disclosures about balance sheet offsetting as issued by the Financial Accounting Standards Board (FASB) to enable readers to evaluate the effects of netting arrangements on the Partnership's financial position. Adoption of the ASU has resulted in increased qualitative and quantitative disclosures (see note 18) regarding certain derivative instruments that are either offset in accordance with current GAAP or are subject to a master netting arrangement or similar agreement.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Partnership adopted the ASU on reporting of amounts reclassified out of AOCI as issued by the FASB. Adoption of the ASU has resulted in providing additional qualitative and quantitative disclosures regarding significant amounts reclassified out of accumulated other comprehensive income into net income (see note 10).

NOTE 4 INVESTMENTS IN UNCONSOLIDATED AFFILIATES

Great Lakes and Northern Border are regulated by FERC and are operated by TransCanada. We use the equity method of accounting for our interests in our equity investees.

(millions of dollars)	**Ownership Interest at December 31, 2013**	Equity Earnings from Unconsolidated Affiliates Year ended December 31			Investment in Unconsolidated Affiliates December 31	
		2013	2012	2011	**2013**	2012
Northern Border[(a)]	50%	**64**	72	75	**523**	512
Great Lakes	46.45%	**3**	27	60	**672**	677
		67	99	135	**1,195**	1,189

(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 additional 20 percent acquisition in April 2006.

Northern Border

The Partnership owns a 50 percent general partner interest in Northern Border. The other 50 percent partnership interest in Northern Border is held by ONEOK Partners, L.P., a publicly traded limited partnership.

TC PipeLines Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Northern Border. The Partnership holds a 98.9899 percent limited partnership interest in TC PipeLines Intermediate Limited Partnership.

Northern Border has a FERC-approved settlement agreement which established maximum long-term transportation rates and charges on the Northern Border system effective January 1, 2013. The Northern Border Settlement also includes a three-year moratorium on filing rate cases and requires Northern Border to file for new rates no later than January 1, 2018. Northern Border's reservations rates were reduced by approximately 11 percent.

The Partnership recorded no undistributed earnings from Northern Border for the years ended December 31, 2013, 2012 and 2011.

At December 31, 2013, the Partnership had a $118 million (2012 – $119 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 Partnership made an equity contribution to Northern Border of $31 million in the fourth quarter of 2013. This amount represents the Partnership's 50 percent share of a $62 million cash call from Northern Border to fund repayment of the Northern Border Credit Facility.

The summarized financial information for Northern Border is as follows:

December 31 (millions of dollars)	2013	2012
Assets		
Cash and cash equivalents	**27**	28
Other current assets	**34**	35
Plant, property and equipment, net	**1,197**	1,234
Other assets	**33**	31
	1,291	1,328
Liabilities and Partners' Equity		
Current liabilities	**51**	53
Deferred credits and other	**19**	16
Long-term debt, including current maturities	**411**	473
Partners' equity		
Partners' capital	**812**	789
Accumulated other comprehensive loss	**(2)**	(3)
	1,291	1,328

Year ended December 31 (millions of dollars)	2013	2012	2011
Transmission revenues	**286**	311	310
Operating expenses	**(75)**	(79)	(73)
Depreciation	**(58)**	(63)	(62)
Financial charges and other	**(23)**	(24)	(22)
Net income	**130**	145	153

Great Lakes

The Partnership owns a 46.45 percent general partner interest in Great Lakes. TransCanada owns the other 53.55 percent partnership interest. TC GL Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Great Lakes. The Partnership holds a 98.9899 percent limited partnership interest in TC GL Intermediate Limited Partnership.

On November 14, 2013, FERC approved a settlement between Great Lakes and its customers to modify its transportation rates effective November 1, 2013. The settlement increases maximum recourse transportation rates by approximately 21 percent. The settlement includes a moratorium on filing rate cases or challenging the settlement rates until March 31, 2015 and requires that Great Lakes file to have new rates in effect no later than January 1, 2018.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2013, 2012, and 2011.

At December 31, 2013, the Partnership had a $458 million (2012 – $458 million) difference between the carrying value of Great Lakes and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in the Partnership's investment in Great Lakes relating to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes.

The Partnership made equity contributions to Great Lakes of $4 million and $5 million in the first and fourth quarter of 2013, respectively. These amounts represent the Partnership's 46.45 percent share of a $9 million and $10 million cash call from Great Lakes to make scheduled debt repayments.

The summarized financial information for Great Lakes is as follows:

December 31 (millions of dollars)	**2013**	2012
Assets		
Current assets	**52**	56
Plant, property and equipment, net	**771**	799
	823	855
Liabilities and Partners' Equity		
Current liabilities	**28**	30
Long-term debt, including current maturities	**335**	354
Partners' equity	**460**	471
	823	855

Year ended December 31 (millions of dollars)	**2013**	2012	2011
Transmission revenues	**124**	182	250
Operating expenses	**(60)**	(66)	(62)
Depreciation	**(31)**	(31)	(32)
Financial charges and other	**(27)**	(28)	(30)
Michigan business tax	**–**	–	2
Net income	**6**	57	128

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

The following table includes plant, property and equipment from GTN, Bison, North Baja and Tuscarora.

	2013			2012[a]		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**2,045**	**(522)**	**1,523**	2,040	(462)	1,578
Compression	**520**	**(120)**	**400**	514	(112)	402
Metering and other	**146**	**(32)**	**114**	142	(26)	116
Construction in progress	**5**	**–**	**5**	15	–	15
	2,716	**(674)**	**2,042**	2,711	(600)	2,111

[a] Recast as discussed in Note 2 and Note 6.

NOTE 6 ACQUISITIONS

2013 Acquisition

On July 1, 2013, the Partnership acquired an additional 45 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada. GTN and Bison are both Delaware limited liability companies regulated by FERC, and they are operated by subsidiaries of TransCanada. The GTN pipeline system extends from an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border. The Bison pipeline system extends from the Powder River Basin near Gillette, Wyoming to Northern Border's pipeline system in Morton County, North Dakota.

The total purchase price of the 2013 Acquisition was $1,050 million plus purchase price adjustments. The purchase price consisted of (i) $750 million for the GTN membership interest (less $146 million, which reflected 45 percent of GTN's outstanding debt at the time of the 2013 Acquisition), (ii) $300 million for the membership interest in Bison, (iii) $17 million in working capital adjustments and (iv) Carty Lateral consideration of $25 million (see below).

The resulting $921 million (after working capital adjustments) paid by the Partnership was financed through a combination of (i) a public offering of 8,855,000 common units at $43.85 per common unit resulting in net proceeds of $373 million (refer to note 9), (ii) borrowing of $500 million in term loans (refer to note 7), (iii) a capital contribution from the General Partner of $8 million which was required to maintain the General Partner's effective two percent general partner interest in the Partnership (refer to note 9), and (iv) a draw on the Partnership's existing $500 million Senior Credit Facility and cash on hand.

Pursuant to the acquisition agreement between the Partnership and TransCanada relating to the Partnership's acquisition of an additional 45 percent membership interest in GTN, the Partnership agreed to make an additional payment of $25 million to TransCanada if Portland General Electric Company executes a firm transportation service agreement by December 31, 2014 containing agreed terms and relating to transportation on GTN's proposed Carty Lateral. On December 11, 2013, Portland General Electric Company executed this firm transportation service agreement relating to transportation on GTN's proposed Carty Lateral. As a result, the Partnership will pay an additional $25 million by April 11, 2014. This amount was included in accounts payable to affiliates as of December 31, 2013.

The 2013 Acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of GTN and Bison were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to consolidate GTN and Bison for all periods presented.

The purchase price was recorded as follows:

(millions of dollars)	
Current assets	67
Property, plant and equipment, net	1,792
Other assets	1
Current liabilities	(20)
Other liabilities	(21)
Long-term debt	(325)
	1,494
Non-controlling interest	(448)
Carrying value of pre-existing 25% interest in each of GTN and Bison	(374)
Carrying value of acquired 45% interest in each of GTN and Bison	672
Excess purchase price over net assets acquired (includes Carty Lateral consideration)	274
Total cash consideration including $25 million Carty Lateral consideration payable	**946**

As the fair market value for the additional 45 percent interests in each of GTN and Bison was greater than the acquired net assets of GTN and Bison by $262 million and $12 million, respectively, the total excess purchase price of $274 million was recorded in Partners' Equity, including the Carty Lateral consideration. The retrospective consolidation of GTN and Bison increased net income attributable to common units by $26 million for the year ended December 31, 2013 and by $55 million and $59 million for the years ended December 31, 2012 and 2011, respectively. These amounts are however, excluded from equity attributable to controlling interests.

2011 Acquisition

On May 3, 2011, the Partnership acquired a 25 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada (the 2011 Acquisition).

The total purchase price of the 2011 Acquisition was $605 million. The purchase price consisted of (i) $405 million for the GTN membership interest (less $81 million, which reflected 25 percent of GTN's outstanding debt at the time of the 2011 Acquisition), (ii) $200 million for the membership interest in Bison (less a $9 million future capital commitment to complete the Bison pipeline) (iii) $23 million at closing and (iv) $1 million in working capital adjustments paid in the fourth quarter of 2011. The resulting $539 million paid by the Partnership was financed through a combination of (i) an issuance of 7,245,000 common units offered to the public at $47.58 per common unit resulting in net proceeds of $331 million, (ii) a draw of $61 million on the Partnership's committed $400 million bridge loan facility, (iii) a draw of $125 million on the Partnership's then existing $250 million senior revolving credit facility, (iv) a capital contribution from the General Partner of $7 million, which was required to maintain the General Partner's effective two percent general partner interest in the Partnership, and (v) approximately $15 million of cash on hand.

The 2011 Acquisition was accounted for as a transaction between entities under common control, whereby the equity investments in both GTN and Bison were recorded at TransCanada's carrying values, and the total excess purchase price paid of $131 million was recorded as a reduction to Partners' Equity in 2011.

On July 22, 2013, a subsidiary of TransCanada paid $1 million to the Partnership in relation to the 2011 Acquisition of a 25 percent interest in Bison as a post-closing construction expenditures adjustment.

Yuma Lateral Asset Acquisition

Pursuant to an amendment to the acquisition agreement between the Partnership and TransCanada relating to the Partnership's acquisition of North Baja, the partnership agreed to make an additional payment of up to $2 million to TransCanada in the event that TransCanada secured additional contracts for transportation service before December 31, 2010. TransCanada secured an additional contract in July 2010 and, as a result, the Partnership paid $2 million to TransCanada on March 25, 2011 when the facilities associated with the contract were completed.

NOTE 7 CREDIT FACILITIES AND LONG-TERM DEBT

December 31 (millions of dollars)	**2013**	2012[(a)]
Senior Credit Facility due 2017	**380**	312
Term Loan Facility due 2018	**500**	–
4.65% Unsecured Senior Notes due 2021	**349**	349
5.09% Unsecured Senior Notes due 2015	**75**	75
5.29% Unsecured Senior Notes due 2020	**100**	100
5.69% Unsecured Senior Notes due 2035	**150**	150
3.82% Series D Senior Notes due 2017	**24**	27
	1,578	1,013
Less: current portion of long-term debt	**3**	3
	1,575	1,010

(a) Recast as discussed in Note 2 and Note 6.

The Partnership's Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, maturing November 20, 2017, under which $380 million was outstanding at December 31, 2013 (2012 – $312 million), leaving $120 million available for future borrowing.

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be 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 $250 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 averaged 1.44 percent for the year ended December 31, 2013 (2012 – 1.61 percent; 2011 – 0.86 percent (4.07 percent after hedging)). The interest rate was 1.42 percent at December 31, 2013 (December 31, 2012 – 1.47 percent).

On July 1, 2013, the Partnership entered into a term loan agreement with a syndicate of lenders for a $500 million term loan credit facility (Term Loan Facility). On July 2, 2013, the Partnership borrowed $500 million under the Term Loan Facility, to pay a portion of the purchase price of the 2013 Acquisition, maturing on July 1, 2018. The 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 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 2.000 percent for LIBOR borrowings and 0.125 percent and 1.000 percent for base rate borrowings.

The LIBOR-based interest rate on the Term Loan Facility averaged 1.43 percent for the year ended December 31, 2013. After hedging activity, the interest rate incurred on the Term Loan Facility averaged 1.70 percent for the year ended December 31, 2013. Prior to hedging activities, the LIBOR-based interest rate was 1.42 percent at December 31, 2013.

GTN's Senior Notes provisions contain a covenant that limits total debt to no greater than 70 percent of total capitalization. Series D Senior Notes are secured by Tuscarora's transportation contracts, supporting agreements and substantially all of Tuscarora's property. The note purchase agreements contain certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners.

At December 31, 2013, 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 second amended and restated agreement of limited partnership (Partnership Agreement), incurring additional debt and distributions to unitholders.

The principal repayments required by the Partnership on the long-term debt are as follows:

(millions of dollars)	
2014	**3**
2015	**79**
2016	**4**
2017	**393**
2018	**500**
Thereafter	**599**
	1,578

NOTE 8 OTHER LIABILITIES

December 31 (millions of dollars)	**2013**	2012[a]
Regulatory liabilities	**22**	20
Fair value of derivative contracts *(Note 18)*	**–**	–
Other liabilities	**2**	1
	24	21

[a] Recast as discussed in Note 2 and Note 6.

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates 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*.

NOTE 9 PARTNERS' EQUITY

At December 31, 2013, Partners' equity included 62,327,766 common units (December 31, 2012 and 2011 – 53,472,766 common units), representing an aggregate 98 percent limited partner interest in the Partnership (including 5,797,106 common units held by the General Partner and 11,287,725 common units held indirectly by TransCanada) and an aggregate two percent general partner interest. In aggregate, the General Partner's interests represent an effective 11.1 percent ownership in the Partnership at December 31, 2013 (December 31, 2012 and 2011 – 12.6 percent).

On May 22, 2013, the Partnership closed a public offering of 8,855,000 common units, including 1,155,000 common units purchased pursuant to the exercise of the underwriters' option to purchase additional common units, at a price to the public of $43.85 per common unit for gross proceeds of $388 million and net proceeds of $373 million after unit issuance costs. The General Partner maintained its effective two percent general partner interest in the Partnership by contributing $8 million to the Partnership in connection with the offering. See Note 6 for additional information regarding the equity issuance in connection with the 2013 Acquisition.

On May 3, 2011, the Partnership completed a public offering of 7,245,000 common units at $47.58 per common unit for gross proceeds of $345 million and net proceeds of $331 million after unit issuance costs. The General Partner maintained its effective two percent general partner interest in the Partnership by contributing $7 million to the Partnership in connection with the offering. See Note 6 for additional information regarding the equity issuance in connection with the 2011 Acquisition.

NOTE 10 ACCUMULATED OTHER COMPEREHENSIVE LOSS

The changes in accumulated other comprehensive loss (AOCL) by components are as follows:

Years ended December 31, 2013 and 2012 (millions of dollars)	**Cash flow hedges**	**Total**
AOCL Balance as of January 1, 2013 and 2012	**(1)**	**(1)**
Other comprehensive loss before reclassifications	**–**	**–**
Amounts reclassified from AOCL (affected financial charges and other)	**–**	**–**
Net other comprehensive loss	**–**	**–**
AOCL Balance as of December 31, 2013 and 2012	**(1)**	**(1)**

Year ended December 31, 2011 (millions of dollars)	**Cash flow hedges**	**Total**
AOCL Balance as of January 1, 2011	(15)	(15)
Other comprehensive loss before reclassifications	–	–
Amounts reclassified from AOCL (affected financial charges and other)	14	14
Net other comprehensive income	14	14
AOCL Balance as of December 31, 2011	(1)	(1)

NOTE 11 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	**2013[(a)]**	2012[(a)]	2011[(a)]
Interest expense	**42**	40	34
Amortization of debt issue costs	**1**	1	2
Net realized loss related to the interest rate swaps and options	**1**	–	14
Interest income	**–**	–	(2)
Other	**–**	(1)	(2)
	44	40	46

(a) Recast as discussed in Note 2 and Note 6.

NOTE 12 NET INCOME PER COMMON UNIT

Net income per common unit is computed by dividing net income attributable to controlling interests, after deduction of the General Partner's allocation and net income attributed to GTN's and Bison's former parent, by the weighted average number of common units outstanding. The General Partner's allocation is equal to an amount based upon the General Partner's effective two percent general partner interest, plus an amount equal to incentive distributions. Incentive distributions are paid to the General Partner if quarterly cash distributions on the common units exceed levels specified in the Partnership Agreement.

Net income per common unit was determined as follows:

(millions of dollars, except per common unit amounts)	**2013[a]**	2012[a]	2011[a]
Net income	**191**	229	250
Net income attributed to GTN's and Bison's former parent	**(26)**	(55)	(59)
Net income attributable to non-controlling interests	**(36)**	(37)	(34)
Net income allocated to partners[b]	**129**	137	157
Net income allocated to General Partner	**3**	3	3
Net income allocable to common units	**126**	134	154
Weighted average common units outstanding *(millions)* – basic and diluted	**58.9**	53.5	51.1
Net income per common unit – basic and diluted	**$2.13**	$2.51	$3.02

[a] Recast as discussed in Note 2 and Note 6.

[b] Net income allocated to partners excludes net income attributed to GTN's and Bison's former parent as it was allocated to TransCanada and was not allocable to either the general partner or common units.

NOTE 13 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. The unitholders currently receive a quarterly distribution of $0.81 per common unit if and to the extent there is sufficient Available Cash.

As an incentive, the General Partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. Currently, the combined general partner interest and incentive distribution interest payable to the General Partner is 15 percent to a maximum of 25 percent of all quarterly distributions of Available Cash that exceed target levels of $0.81 and $0.88, respectively, per common unit.

For the year ended December 31, 2013, the Partnership distributed $3.18 per common unit (2012 – $3.10 per common unit; 2011 – $3.04 per common unit) for a total of $188 million (2012 – $169 million; 2011 – $155 million). The distributions paid for the years ended December 31, 2013, 2012 and 2011 included no incentive distributions to the General Partner. Partnership income attributable to controlling interests is allocated to the General Partner and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated 100 percent to the General Partner.

NOTE 14 CHANGE IN OPERATING WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2013[a]**	2012[a]	2011[a]
Change in accounts receivable and other	**1**	2	3
Change in accounts payable and accrued liabilities	**(9)**	(2)	(3)
Change in accounts payable to affiliates	**(2)**	–	–
Change in accrued interest	**2**	–	–
Change in operating working capital	**(8)**	–	–

[a] Recast as discussed in Note 2 and Note 6.

NOTE 15 TRANSACTIONS WITH MAJOR CUSTOMERS

The following table shows revenues from the Partnership's major customers comprising more than 10 percent of the Partnership's total revenues for the years ended December 31, 2013, 2012 and 2011:

Year Ended December 31 (millions of dollars)	**2013[(a)]**	2012[(a)]	2011[(a)]
Anadarko Energy Services Company	**48**	48	45
Pacific Gas and Electric Company	**46**	47	68

(a) Recast as discussed in Note 2 and Note 6.

NOTE 16 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 were $3 million for the year ended December 31, 2013 (2012 – $3 million; 2011 – $2 million).

As operator, TransCanada's subsidiaries provide capital and operating services to GTN, Northern Border, Bison, Great Lakes, North Baja and Tuscarora (together, "our pipeline systems"). TransCanada's subsidiaries incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, and property and liability insurance costs.

Capital and operating costs charged to our pipeline systems for the years ended December 31, 2013, 2012 and 2011 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2013 and 2012 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2013**	2012	2011
Capital and operating costs charged by TransCanada's subsidiaries to:			
GTN[(a)(b)]	**28**	29	33
Northern Border[(a)]	**30**	31	29
Bison[(a)(b)]	**5**	6	11
Great Lakes[(a)]	**31**	33	31
North Baja	**4**	4	4
Tuscarora	**4**	4	5
Impact on the Partnership's net income attributable to controlling interests:			
GTN[(b)]	**19**	19	22
Northern Border	**14**	14	13
Bison[(b)]	**4**	4	4
Great Lakes	**14**	15	14
North Baja	**4**	4	4
Tuscarora	**4**	4	5

December 31 (millions of dollars)	**2013**	2012
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
GTN[(a)]	**3**	3
Northern Border[(a)]	**3**	4
Bison[(a)]	**–**	1
Great Lakes[(a)]	**3**	4
North Baja	**1**	1
Tuscarora	**–**	1

(a) Represents 100 percent of the costs.

(b) Recast as discussed in Note 2 and Note 6.

Great Lakes' earns transportation revenues from TransCanada and its affiliates under contracts, some of which are provided at discounted rates and some at maximum recourse rates. Great Lakes earned $68 million of transportation revenues under these contracts in 2013 (2012 – $77 million; 2011 – $81 million). This amount represents 55 percent of total revenues earned by Great Lakes in 2013 (2012 – 42 percent; 2011 – 32 percent). Great Lakes also earned $1 million in affiliated rental revenue in 2013 (2012 – $1 million; 2011 – $1 million).

Revenue from TransCanada and its affiliates of $32 million is included in the Partnership's equity earnings from Great Lakes in 2013 (2012 – $36 million; 2011 – $38 million). At December 31, 2013, $11 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2012 – $10 million).

The Partnership accrued $25 million of additional consideration in accordance with the 2013 Acquisition with respect to Carty Lateral. This amount is payable to a subsidiary of TransCanada and is included in accounts payable to affiliates as of December 31, 2013 (refer to Note 6).

Bison's former parent made an equity contribution to Bison of $18 million in the second quarter of 2013. This amount represents the former parent's 75 percent share of a $24 million cash call from Bison to repay inter-affiliate debt primarily related to pipeline construction costs, including reclamation and restoration work. In 2011, Bison's former parent made an equity contribution to Bison of $305 million related to pipeline system construction costs.

Effective October 1, 2013, GTN and Bison participate in the Partnership's cash management program. Prior to this, GTN and Bison were part of TransCanada's cash management program. This program matches short-term cash surpluses and borrowing requirements of participating subsidiaries, thus minimizing total borrowing from outside sources. Funds advanced under the program are considered to be a loan, accruing interest and repayable on demand. GTN and Bison will receive interest on funds advanced to the Partnership at the rate of interest earned by the Partnership on its short-term cash investments and will pay interest on funds advanced from the Partnership based on the Partnership's short-term borrowing costs. At December 31, 2013, GTN and Bison did not have any demand loan receivable from an affiliate or a demand loan payable to an affiliate (December 31, 2012 – a demand loan receivable from an affiliate of $21 million and a demand loan payable to an affiliate of $15 million).

NOTE 17 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2013 and 2012:

Quarter ended (millions of dollars except per common unit amounts)	**Mar 31**	**Jun 30**	**Sept 30**	**Dec 31**
2013				
Transmission revenues[(a)]	**86**	**82**	**85**	**88**
Equity earnings[(a)]	**18**	**15**	**15**	**19**
Net income[(a)]	**53**	**42**	**46**	**50**
Net income attributable to controlling interests[(a)]	**43**	**34**	**37**	**41**
Net income per common unit	**$0.52**	**$0.40**	**$0.58**	**$0.63**
Cash distribution paid	**43**	**43**	**52**	**52**
2012				
Transmission revenues[(a)]	88	84	84	87
Equity earnings[(a)]	29	24	24	22
Net income[(a)]	65	54	57	53
Net income attributable to controlling interests[(a)]	54	46	48	44
Net income per common unit	$0.71	$0.60	$0.64[(b)]	$0.56
Cash distributions paid	42	42	43	43

(a) Recast as discussed in Note 2 and Note 6.

(b) Net Income per common unit has been revised and is presented consistent with our presentation prior to the recast. This change conforms to our presentation for a previous common control transaction in 2009 to ensure consistency. As a result of this change, we decreased recast net income by the amount of net income attributed to GTN's and Bison's former parent in order to compute net income per common unit. It had no impact on these financial statements except as presented below:

Quarter ended September 30, 2012	As previously recast	Adjustment	Revised
Net income per common unit	$0.88	$(0.24)	$0.64

NOTE 18 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, demand loan receivable from affiliate, accounts payable and accrued liabilities, accounts payable to affiliates, accrued interest, and demand loan payable to affiliates 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 estimated fair value of the Partnership's long-term debt as at December 31, 2013 and 2012 are as follows:

	2013		2012[a]	
December 31 (millions of dollars)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Senior Credit Facility due 2017	**380**	**380**	312	312
Term Loan Facility due 2018	**500**	**500**	–	–
4.65% Senior Notes due 2021	**349**	**353**	349	372
5.09% Unsecured Senior Notes due 2015	**75**	**79**	75	83
5.29% Unsecured Senior Notes due 2020	**100**	**106**	100	123
5.69% Unsecured Senior Notes due 2035	**150**	**154**	150	201
3.82% Series D Senior Notes due 2017	**24**	**25**	27	30
	1,578	**1,597**	1,013	1,121

[a] Recast as discussed in Note 2 and Note 6.

Long-term debt is recorded at amortized cost and classified in Level II of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified in Level II for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices.

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 interest rate swaps are structured such that the cash flows of the derivative instruments match those of the variable rate of interest on the Term Loan Facility. The Partnership hedged interest payments on $150 million of variable-rate Term Loan Facility with interest rate swaps effective September 3, 2013 and maturing July 1, 2018, at a weighted average fixed interest rate of 2.79 percent. At December 31, 2013, the fair value of the interest rate swaps accounted for as cash flow hedges was less than $1 million (both on a gross and net basis) (December 31, 2012 and 2011 – nil). In 2013, the Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges. The change in fair value of interest rate derivative instruments recognized in other comprehensive income was less than $1 million for the year ended December 31, 2013. In 2013, the net realized loss related to the interest rate swaps was $1 million and was included in financial charges and other (2012 – nil; 2011 – $14 million).

Until December 12, 2011, the Partnership used derivatives to assist in managing its exposure to interest rate risk relating to the Senior Credit Facility. The interest rate swaps and options were structured such that the cash flows matched those of the Senior Credit Facility. There were no amounts hedged at December 31, 2012 and 2011. $300 million of variable-rate debt was hedged by an interest rate swap through December 12, 2011, where the fixed interest rate paid was 4.89 percent. $75 million of variable-rate debt was hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid was 3.86 percent. In addition to these fixed rates, the Partnership paid an applicable margin in accordance with the Senior Credit Facility agreement.

The Partnership has no master netting agreements, however, 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, 2013 and 2012.

Counterparty credit risk represents the financial loss that the Partnership 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. Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consists primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 31, 2013, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2013, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $37 million (2012 – $59 million).

NOTE 19 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2013**	2012[(a)]
Trade accounts receivable, net of allowance of nil	**33**	31
Accounts receivable from affiliates	**–**	1
Other	**4**	6
	37	38

(a) Recast as discussed in Note 2 and Note 6.

NOTE 20 REGULATORY MATTERS

North Baja – On January 6, 2014, FERC approved North Baja's application to temporarily abandon compression associated with the original design of its pipeline system. This temporary abandonment will preserve replacement options while reducing maintenance requirements and related expenses without any reduction in capacity or impact to existing firm transportation service.

NOTE 21 CONTINGENCIES

In December 2009, PacifiCorp filed suit against GTN and Northwest Pipeline in Oregon State Court for approximately $7 million for alleged damage to equipment at its natural gas generating facility in Hermiston, Oregon. Upon GTN motion, the case was removed to the U.S. District Court for the District of Oregon and was scheduled for trial in March 2014. However, in February 2014, the parties settled all claims in the case. The impact on the Partnership's consolidated results was not material.

NOTE 22 SUBSEQUENT EVENTS

On January 16, 2014, the board of directors of our General Partner declared the Partnership's fourth quarter 2013 cash distribution in the amount of $0.81 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2014 to unitholders of record as of January 28, 2014, totaled $52 million and was paid in the following manner: $51 million to common unitholders (including $5 million to the General Partner as holder of 5,797,106 common units and $9 million to TransCanada as holder of 11,287,725 common units) and $1 million to the General Partner in respect of its two percent general partner interest.

GTN declared its fourth quarter 2013 distribution of $28 million on January 9, 2014, of which the Partnership received its 70 percent share or $20 million. The distribution was paid on February 3, 2014.

Northern Border declared its fourth quarter 2013 distribution of $43 million on February 3, 2014, of which the Partnership received its 50 percent share or $21 million. The distribution was paid on February 3, 2014.

Bison declared its fourth quarter 2013 distribution of $17 million on January 9, 2014, of which the Partnership received its 70 percent share or $12 million. The distribution was paid on February 3, 2014.

Great Lakes declared its fourth quarter 2013 distribution of $12 million on January 9, 2014, of which the Partnership received its 46.45 percent share or $5 million. The distribution was paid on February 3, 2014.

NORTHERN BORDER PIPELINE COMPANY
INDEPENDENT AUDITORS' REPORT

The Management Committee
Northern Border Pipeline Company:

Report on the Financial Statements

We have audited the accompanying financial statements of Northern Border Pipeline Company (the Company), which comprise the balance sheets as of December 31, 2013 and 2012, and the related statements of income, comprehensive income, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013 and 2012, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2013, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 12, 2014

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, 2013 and 2012 (In thousands)	**2013**	2012
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 26,660**	28,391
Accounts receivable	**24,872**	26,434
Related party receivables	**1,739**	581
Materials and supplies, at cost	**5,469**	5,289
Prepaid expenses and other	**2,198**	2,378
Total current assets	**60,938**	63,073
Property, plant and equipment:		
Natural gas transmission plant	**2,565,331**	2,545,596
Construction work in progress	**1,091**	7,034
Total property, plant and equipment	**2,566,422**	2,552,630
Less: Accumulated provision for depreciation and amortization	**1,369,102**	1,318,759
Property, plant and equipment, net	**1,197,320**	1,233,871
Other assets:		
Regulatory assets	**30,337**	28,117
Debt issuance costs	**2,338**	2,764
Total other assets	**32,675**	30,881
Total assets	**$1,290,933**	1,327,825
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 6,305**	10,164
Related party payables	**3,037**	3,589
Accrued taxes other than income	**31,168**	29,763
Accrued interest	**6,948**	6,931
Other	**3,481**	2,072
Total current liabilities	**50,939**	52,519
Long-term debt, net of current maturities	**411,161**	472,630
Deferred credits and other liabilities:		
Regulatory liabilities	**17,110**	14,620
Other	**2,116**	1,422
Total deferred credits and other liabilities	**19,226**	16,042
Total liabilities	**481,326**	541,191
Partners' equity:		
Partners' capital	**811,898**	789,137
Accumulated other comprehensive loss	**(2,291)**	(2,503)
Total partners' equity	**809,607**	786,634
Total liabilities and partners' equity	**$1,290,933**	1,327,825

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

Years ended December 31, 2013, 2012 and 2011 *(In thousands)*	**2013**	2012	2011
Operating revenue	**$285,849**	310,869	310,070
Operating expenses:			
Operations and maintenance	**51,710**	55,658	50,405
Depreciation and amortization	**58,231**	63,090	61,583
Taxes other than income	**23,052**	23,069	22,824
Operating expenses	**132,993**	141,817	134,812
Operating income	**152,856**	169,052	175,258
Interest expense:			
Interest expense	**27,286**	27,547	26,547
Interest expense capitalized	**(90)**	(84)	(210)
Interest expense, net	**27,196**	27,463	26,337
Other income (expense):			
Allowance for equity funds used during construction	**289**	313	479
Other income	**4,176**	3,570	3,367
Other expense	**(32)**	(62)	(37)
Other income, net	**4,433**	3,821	3,809
Net income to partners	**$130,093**	145,410	152,730

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2013, 2012 and 2011 *(In thousands)*	**2013**	2012	2011
Net income to partners	**$130,093**	145,410	152,730
Other comprehensive income:			
Changes associated with hedging transactions	**212**	197	183
Total comprehensive income	**$130,305**	145,607	152,913

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

Years Ended December 31, (In thousands)	**2013**	2012	2011
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	**$ 130,093**	$ 145,410	$ 152,730
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	**58,263**	63,122	61,615
Allowance for equity funds used during construction	**(289)**	(313)	(479)
Changes in components of working capital	**(470)**	922	(4,199)
Other	**729**	2,052	(84)
Total adjustments	**58,233**	65,783	56,853
Net cash provided by operating activities	**188,326**	211,193	209,583
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	**(20,683)**	(24,192)	(29,661)
Other	**(542)**	–	–
Net cash used in investing activities	**(21,225)**	(24,192)	(29,661)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	**61,500**	–	109,587
Distributions to partners	**(168,832)**	(191,385)	(198,110)
Proceeds from issuance of debt	**45,000**	25,000	74,000
Repayment of debt	**(106,500)**	(25,000)	(142,000)
Debt issuance costs	**–**	(40)	(815)
Net cash used in financing activities	**(168,832)**	(191,425)	(157,338)
Net change in cash and cash equivalents	**(1,731)**	(4,424)	22,584
Cash and cash equivalents at beginning of year	**28,391**	32,815	10,231
Cash and cash equivalents at end of year	**$ 26,660**	$ 28,391	$ 32,815
Supplemental disclosure for cash flow information:			
Cash paid for interest, net of amount capitalized	**$ 26,510**	$ 27,022	$ 25,809
Accruals for property, plant and equipment	**–**	2,529	–
Changes in components of working capital:			
Accounts receivable	**$ 1,651**	$ 1,165	$ 3,441
Related party receivables	**(1,246)**	146	(362)
Materials and supplies	**(181)**	(150)	(828)
Prepaid expenses and other	**179**	(196)	(875)
Accounts payable	**(788)**	(684)	(2,206)
Related party payables	**(551)**	193	381
Accrued taxes other than income	**(960)**	(597)	(1,485)
Accrued interest	**17**	(192)	79
Other current liabilities	**1,409**	1,237	(2,344)
Total	**$ (470)**	$ 922	$ (4,199)

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 Intermediate Limited Partnership	ONEOK Partners Intermediate Limited Partnership	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
Partners' equity at December 31, 2010	$385,452	$385,453	$(2,883)	$768,022
Net income to partners	76,365	76,365	–	152,730
Changes associated with hedging transactions	–	–	183	183
Equity contributions received	54,794	54,793	–	109,587
Distributions paid	(99,055)	(99,055)	–	(198,110)
Partners' equity at December 31, 2011	$417,556	$417,556	$(2,700)	$832,412
Net income to partners	72,705	72,705	–	145,410
Changes associated with hedging transactions	–	–	197	197
Distributions paid	(95,692)	(95,693)	–	(191,385)
Partners' equity at December 31, 2012	$394,569	$394,568	$(2,503)	$786,634
Net income to partners	65,046	65,047	–	130,093
Changes associated with hedging transactions	–	–	212	212
Equity contributions received	30,750	30,750	–	61,500
Distributions paid	(84,416)	(84,416)	–	(168,832)
Partners' equity at December 31, 2013	**$405,949**	**$405,949**	**$(2,291)**	**$809,607**

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

NORTHERN BORDER PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

In this report, references to “we,” “us” or “our” collectively refer to Northern Border Pipeline Company.

We are a Texas general partnership formed in 1978. We own a 1,259-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 ownership and voting percentages of our partners at December 31, 2013 and 2012 are as follows:

Partner	Ownership
ONEOK Partners Intermediate Limited Partnership (ONEOK Partners)	50%
TC PipeLines Intermediate Limited Partnership (TC PipeLines)	50%

We are managed by a Management Committee that consists of four members. Each partner designates two members, and TC PipeLines designates one of its members as chairman.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make assumptions and use estimates that affect the reported amounts of assets, liabilities, revenue and expenses as well as the disclosure of contingent assets and liabilities during the reporting period. Actual results could differ from these estimates if the underlying assumptions are incorrect.

(b) Government Regulation

We are subject to regulation by the Federal Energy Regulatory Commission (FERC). Our accounting policies conform to Financial Accounting Standards Board Accounting Standards Codification (ASC) 980, *Regulated Operations*. 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 a summary of regulatory assets, net of amortization, at December 31, 2013 and 2012:

	December 31,		Remaining recovery/ settlement period
	2013	2012	
	(In thousands)		*(Years)*
Fort Peck lease option	**$13,420**	$13,737	37
Pipeline extension project	**3,691**	4,152	8
Volumetric fuel tracker	**1,992**	1,359	Note 1
South Dakota use tax assessment	**11,234**	8,869	Note 2
Total regulatory assets	**$30,337**	$28,117	

Note 1) Volumetric fuel tracker assets or liabilities are settled with in-kind exchanges with customers continually

Note 2) The South Dakota use tax assessment recovery period will be determined at the conclusion of legal proceedings on the matter

At December 31, 2013 and 2012, respectively, we have reflected a regulatory liability of $17.1 million and $14.6 million on the balance sheets, related to negative salvage accrued for estimated net costs of removal of transmission plant. The settlement period for negative salvage value is related to the estimated life of the assets. See the Property, Plant and Equipment and Related Depreciation and Amortization policy in this note for further discussion of negative salvage.

We assess the recoverability of costs recognized as regulatory assets and liabilities and the ability to continue to account for our activities based on the criteria set forth in ASC 980, which includes such factors as regulatory changes and the impact of competition. Our review of these criteria currently supports the continuing application of ASC 980. If we cease to meet the criteria of ASC 980, the related regulatory assets and liabilities would be charged or credited to the statement of income.

(c) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We maintain an allowance for doubtful accounts for estimated losses on accounts receivable and for natural gas imbalances due from shippers and operators if it is determined we will not collect all or part of the outstanding receivable balance. We regularly review our allowance for doubtful accounts and establish or adjust 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 for 2013 and 2012 were not material to our financial statements.

(d) Revenue Recognition

Our revenues are primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For our transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. We do not take ownership of the gas that is transported. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas and other commodities are made at the agreed-upon delivery point. We are subject to FERC regulations, and as a result, revenues we collect may be subject to refund in a rate proceeding. We establish provisions for these potential refunds. As of December 31, 2013 and 2012, there are no provisions reflected in these financial statements.

(e) Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these financial statements.

(f) Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less.

(g) Materials and Supplies

Materials and supplies are valued at cost with cost determined using the average cost method.

(h) Property, Plant and Equipment and Related Depreciation and Amortization

Property, plant, and equipment are recorded at their original cost of construction. For assets we construct, direct costs are capitalized, 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. We capitalize major units of property replacements or improvements and expense minor items.

We use 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 our last rate proceeding. As a result of the Stipulation and Agreement of Settlement (Northern Border Settlement), the composite depreciation rate was reduced to 2.19 percent from 2.40 percent. For the year ended December 31, 2013, our depreciation rates vary from 2.02 percent to 20 percent. For the years ended December 31, 2012 and 2011, our depreciation rates vary from 2.25 percent to 20 percent per year. Using these rates, the remaining depreciable life of these assets ranges from 1 to 41 years.

When property, plant, and equipment are retired, we charge 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. We do not recognize a gain or loss unless an entire operating unit is sold or retired. We include gains or losses on dispositions of operating units in income.

We 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). AFUDC is calculated based on the Company'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 sheet.

(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, we first compare 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) Asset Retirement Obligation

We account for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. ASC 410-20 requires us to record the fair value of an asset retirement obligation as a liability in the period in which we incur 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 us 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. We have determined that asset retirement obligations exist for certain of our 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 currently establish a liability for the obligations.

We have determined we have legal obligations associated with our natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. We are also required to operate and maintain our natural gas pipeline system, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe our natural gas pipeline system assets have indeterminate lives and, accordingly, have recorded no asset retirement liabilities as of December 31, 2013 and 2012. We continue to evaluate our asset retirement obligations and future developments that could impact amounts we record.

(k) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received by a pipeline system differs from the amount of natural gas scheduled to be delivered or received. We value these imbalances due to or from shippers and interconnecting parties at current index prices. Imbalances are made up in-kind, subject to the terms of our tariff.

Imbalances due from others are reported on the balance sheets as accounts receivable. Imbalances owed to others are reported on the balance sheets as accounts payable. In addition, we classify all imbalances as current as we expect to settle them within a year.

(l) Derivative Instruments and Hedging Activities

We recognize 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.

We only enter into derivative contracts that we intend 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). For all hedging relationships, we formally document the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the hedged transaction, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. We also formally assess, both at the inception of the hedging relationship and on an ongoing basis, whether the derivatives that are used in hedging relationships are highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that are designated and qualify as part of a cash flow hedging relationship, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

We discontinue hedge accounting prospectively when we determine that the derivative is no longer effective in offsetting cash flows attributable to the hedged risk, the derivative expires or is sold, terminated, or exercised, the cash flow hedge is de-designated because a forecasted transaction is not probable of occurring, or management determines to remove the designation of the cash flow hedge.

In all situations in which hedge accounting is discontinued and the derivative remains outstanding, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings. When it is probable that a forecasted transaction will not occur, we discontinue hedge accounting and recognize immediately in earnings gains and losses that were accumulated in other comprehensive income related to the hedging relationship.

(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.

We amortize premiums, discounts and expenses incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

(n) Operating Leases

We have non-cancelable operating leases for office space and rights-of-way. We record rent expense straight-line over the life of the lease.

(o) Contingencies

Our accounting for contingencies covers a variety of business activities including contingencies for legal exposures and environmental exposures. We accrue these contingencies when our 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. We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

(p) Reclassifications

Certain reclassifications have been made to the financial statements for prior years to conform to the current year presentation. These reclassifications did not impact previously reported net income or partners' equity.

3. RATES AND REGULATORY ISSUES

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.

Effective January 1, 2013, we implemented new rates as a result of our Stipulation and Agreement of Settlement. The settlement includes a three-year moratorium on rate changes and requires us to file for new rates no later than January 1, 2018. The settlement establishes maximum long-term transportation rates on our system and current transportation rates will be reduced by approximately 11 percent. In addition, the composite depreciation rate was reduced to 2.19 percent from 2.40 percent, which prospectively increases the depreciable life of our assets.

The compressor usage surcharge rate is designed to recover the actual costs of electricity at our electric compressors and any compressor fuel use taxes imposed on our 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 as either an other current liability or a current asset classified as prepaid expense and other, respectively, on the balance sheets. The compressor usage surcharge rate is adjusted annually. The current liability or current asset 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, 2013, we had recorded $2.3 million as an other current liability on the accompanying balance sheet for the net over recovery of compressor usage related costs. As of December 31, 2012, we had recorded $1.8 million as an other current liability on the accompanying balance sheet for the net over recovery of compressor usage related costs.

4. MAJOR CUSTOMERS

For the year ended December 31, 2013, shippers providing significant operating revenues were Tenaska Marketing Ventures and BP Canada with revenues of $28.8 million and $23.9 million, respectively.

For the year ended December 31, 2012, shippers providing significant operating revenues were Tenaska Marketing Ventures and BP Canada with revenues of $34.2 million and $27.1 million, respectively. For the year ended December 31, 2011, shippers providing significant operating revenues were Tenaska Marketing Ventures and BP Canada with revenues of $30.3 million and $29.9 million, respectively.

5. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

December 31, (In thousands)	**2013**	2012
2011 Credit Agreement – average interest rate of 1.365% at December 31, 2013 due 2016	**$61,500**	$123,000
2001 Senior Notes – 7.50%, due 2021	**250,000**	250,000
2009 Senior Notes – 6.24%, due 2016	**100,000**	100,000
Unamortized debt discount	**(339)**	(370)
Long-term debt	**411,161**	472,630

On November 16, 2011, we entered into a $200 million amended and restated revolving credit agreement (2011 Credit Agreement) with certain financial institutions. The 2011 Credit Agreement was used to refinance the outstanding indebtedness under our $250 million revolving credit agreement dated as of April 27, 2007. The 2011 Credit Agreement can also be used to finance permitted acquisitions, pay related fees and expenses, issue letters of credit and provide for ongoing working capital needs and for other general business purposes, including capital expenditures.

At December 31, 2013, based on the principal commitment amount of $200 million, available capacity under the 2011 Credit Agreement was $138.5 million. We may, at our option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under our 2011 Credit Agreement by an aggregate amount not to exceed $300 million, provided that lenders are willing to commit additional amounts. At our 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 our long-term unsecured credit ratings. The 2011 Credit Agreement permits us to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. We are required to pay a commitment fee based our credit rating and on the unused principal amount of the commitment of $200 million. The term of the agreement is five years, with options for two one-year extensions.

Certain of our long-term debt arrangements contain covenants that restrict the incurrence of secured indebtedness or liens upon property by us. Under the 2011 Credit Agreement, we are required to comply with certain financial, operational and legal covenants. Among other things, we are required to maintain a leverage ratio (total consolidated debt to consolidated EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges)) of no more than 5.00 to 1. 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 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.

Under the 2009 Senior Notes, we may not at any time permit debt secured by liens to exceed 20 percent of partners capital and may not permit total debt, at any time, to exceed 70 percent of total capitalization. At December 31, 2013, we were in compliance with all of our financial covenants.

Aggregate required repayment of long-term debt for the next five years is $161.5 million, all of which is due in 2016. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2014, 2015, 2017 or 2018.

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Prior to December 31, 2001, we terminated a series of interest rate derivatives in exchange for cash. These derivatives had previously been accounted for as hedges with the $4.1 million in accumulated other comprehensive income (loss) (AOCL) recorded as of the termination date. The previously recorded AOCL is currently being amortized under the effected interest method over the remaining term of the related hedged instrument, our 2001 Senior Notes due 2021.

During the three-year period ended December 31, 2013, we reclassified the below amounts from AOCL into earnings for these terminated derivatives.

Net Loss Reclassified from AOCL into Income (Effective Portion) *(In thousands)*	Statements of Income Caption	Years Ended December 31, 2013	2012	2011
Cash flow hedges	Interest expense	**$(212)**	$(197)	$(183)

Accumulated AOCL was $2.3 million at December 31, 2013 and will be amortized into earnings through 2021 as noted above. We expect to reclassify approximately $0.2 million from AOCL as an increase to interest expense in 2014. We had no other derivative instruments during the year period ended December 31, 2013.

7. 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 following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2013 and 2012. The fair value of a financial instrument is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

	2013		2012	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	**$26,660**	**$26,660**	$28,391	$28,391
Financial liabilities:				
Long-term debt	**$411,161**	**$462,236**	$472,630	$545,098

Cash and cash equivalents – The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

Long-term debt – The fair value of our senior notes were estimated based on quoted market prices for 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 technique that refers to observable market data. We presently intend to maintain the current schedule of maturities for the 2001 and 2009 Senior Notes, which will result in no gains or losses on their respective repayments. The fair value of the 2011 Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

(c) Other Recurring Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of other items measured and recorded at fair value on a recurring basis as of December 31, 2013 and 2012:

	2013		2012	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Related party natural gas imbalance asset	**$938**	**$938**	$89	$89
Natural gas imbalance asset	**$–**	**$–**	$351	$351
Natural gas imbalance liability	**$1,761**	**$1,761**	$1,520	$1,520

Natural Gas Imbalances – 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. We value 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 average of the Northern Ventura index price and the Chicago city-gates index price. We have classified the fair value of natural gas imbalances 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.

8. COMMITMENTS AND CONTINGENCIES

Operating Leases

We make lease payments under non-cancelable operating leases on office space and rights-of-way. Expenses incurred related to these lease obligations for the years ended December 31, 2013, 2012, and 2011 were $2.9 million, $4.0 million, and $2.3 million, respectively. Our future minimum lease payments are as follows:

Year ending December 31, (In thousands)	
2014	1,921
2015	1,922
2016	2,198
2017	2,189
2018	2,189
Thereafter	48,838
	$59,257

In August 2004, we signed an Option Agreement and Expanded Facilities Lease (Option Agreement) with the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. The Option Agreement granted to us, among other things: (i) an option to renew the pipeline right-of-way lease upon agreed terms and conditions on or before April 1, 2011, for a term of 25 years with a renewal right for an additional 25 years; (ii) a right to use additional tribal lands for expanded facilities; and (iii) release and satisfaction of all tribal taxes against us. In consideration of this option and other benefits, we paid a lump sum amount of $7.4 million and made additional annual option payments through March 31, 2011. In March 2011, we exercised the option and renewed the pipeline right-of-way lease for an initial term of 25 years through March 31, 2036.

Other

Various legal actions that have arisen in the ordinary course of business are pending. We believe that the resolution of these issues will not have a material adverse impact on our results of operations or financial position.

9. CASH DISTRIBUTION AND CONTRIBUTION POLICY

Our General Partnership Agreement provides that distributions to our partners are to be made on a pro rata basis according to each partner's capital account balance. Our Management Committee determines the amount and timing of the distributions to our 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, our cash distribution policy requires the unanimous approval of the Management Committee. Our cash distributions are equal to 100 percent of our distributable cash flow as determined from our financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures.

For the years ended December 31, 2013, 2012, and 2011, we paid distributions to our general partners of $168.8 million, $191.4 million, and $198.1 million, respectively. In 2013, we received contributions from our general partners of $61.5 million, which were used to repay outstanding indebtedness. In 2011, we received contributions from our general partners in the amount of $109.6 million for the previously approved 2011 equity contribution to repay indebtedness and to fund 50 percent of the costs of construction of the Princeton Lateral Project.

10. RELATED PARTY TRANSACTIONS

The day-to-day management of our affairs is the responsibility of TransCanada Northern Border, Inc., (TransCanada Northern Border) pursuant to an operating agreement between TransCanada Northern Border and us effective April 1, 2007. TransCanada Northern Border utilizes the services of TransCanada Corporation (TransCanada) and its affiliates for management services related to us. We are charged for the salaries, benefits and expenses of TransCanada and its affiliates attributable to our operations. For the years ended December 31, 2013, 2012, and 2011, our charges from TransCanada and its affiliates totaled approximately $29.6 million, $30.5 million, and $28.7 million, respectively.

For the years ended December 31, 2013, 2012, and 2011, we had contracted firm capacity held by one shipper affiliated with one of our general partners. Revenue from ONEOK Energy Services Company, LP (ONEOK Energy) and ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), subsidiaries of ONEOK, for 2013, 2012, and 2011 was $8.1 million, $5.6 million, and $4.4 million, respectively. At December 31, 2013 and 2012, we had outstanding receivables from ONEOK Energy and ONEOK Rockies of $0.8 million and $0.5 million, respectively.

11. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $42.7 million was declared and paid on February 3, 2014 for the fourth quarter of 2013.

We have evaluated subsequent events through February 12, 2014, which represents 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 financial statements other than those already reflected.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
Independent Auditors' Report

The Partners and the Management Committee
Great Lakes Gas Transmission Limited Partnership:

Report on the Financial Statements

We have audited the accompanying financial statements of Great Lakes Gas Transmission Limited Partnership (the Partnership), which comprise the balance sheets as of December 31, 2013 and 2012, and the related statements of income and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013 and 2012, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2013, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 12, 2014

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
BALANCE SHEETS

December 31, (In thousands)	**2013**	2012
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 48**	$ 31
Demand loan receivable from affiliate	**21,929**	26,474
Accounts receivable:		
Trade	**5,964**	5,991
Affiliates	**10,778**	10,563
Materials and supplies	**10,703**	10,771
Other	**2,083**	2,123
Total current assets	**51,505**	55,953
Property, plant, and equipment:		
Property, plant, and equipment	**2,069,560**	2,069,305
Construction work in progress	**2,171**	1,292
	2,071,731	2,070,597
Less accumulated depreciation and amortization	**(1,300,815)**	(1,271,707)
Total property, plant, and equipment, net	**770,916**	798,890
Other assets	**461**	507
Total assets	**$ 822,882**	$ 855,350
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable:		
Trade	**$ 4,377**	$ 2,161
Affiliates	**3,176**	5,009
Current maturities of long-term debt	**19,000**	19,000
Taxes payable (other than income)	**11,137**	13,342
Accrued interest	**7,425**	7,738
Other	**1,912**	2,318
Total current liabilities	**47,027**	49,568
Long-term debt, net of current maturities	**316,000**	335,000
Other liabilities	**254**	296
Total Liabilities	**363,281**	384,864
Partners' capital	**459,601**	470,486
Total liabilities and partners' capital	**$ 822,882**	$ 855,350

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF INCOME AND PARTNERS' CAPITAL

Years ended December 31, (In thousands)	**2013**	2012	2011
Operating revenues	**$124,480**	$182,423	$250,006
Operating expenses:			
Operation and maintenance	**44,493**	47,671	44,371
Depreciation and amortization	**30,980**	30,981	32,217
Taxes, other than income	**15,924**	18,798	17,476
Total operating expenses	**91,397**	97,450	94,064
Operating income	**33,083**	84,973	155,942
Other income, net	**141**	479	–
Interest and debt expense	**(26,930)**	(28,412)	(29,929)
Affiliated interest income	**21**	29	40
Income before partnership income taxes	**6,315**	57,069	126,053
Partnership income tax benefit	**–**	186	1,915
Net income	**$6,315**	$57,255	$127,968
Partners' capital:			
Balance at beginning of year	**$470,486**	$488,731	$498,663
Net income	**6,315**	57,255	127,968
Distributions to partners	**(36,200)**	(94,500)	(156,900)
Contributions from partners	**19,000**	19,000	19,000
Balance at end of year	**$459,601**	$470,486	$488,731

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF CASH FLOWS

Years ended December 31, (In thousands)	**2013**	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$ 6,315**	$ 57,255	$ 127,968
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**30,980**	30,981	32,217
Deferred partnership income taxes	**–**	–	(5,153)
Allowance for funds used during construction, equity	**(66)**	(67)	(84)
Gain on sale of assets, net	**–**	(380)	–
Asset and liability changes:			
Accounts receivable	**(188)**	(880)	10,222
Other current assets	**108**	(161)	81
Noncurrent assets	**46**	46	69
Accounts payable	**383**	(3,612)	(3,854)
Partnership income taxes payable	**–**	(3,238)	(491)
Other current liabilities	**(3,666)**	7,517	(735)
Noncurrent liabilities	**(42)**	(140)	–
Net cash provided by operating activities	**33,870**	87,321	160,240
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property, plant, and equipment	**(2,940)**	(3,176)	(11,444)
Net change in demand loan receivable from affiliate	**4,545**	10,339	8,111
Other	**742**	–	–
Net cash provided by (used in) investing activities	**2,347**	7,163	(3,333)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(19,000)
Distributions to partners	**(36,200)**	(94,500)	(156,900)
Contributions from partners	**19,000**	19,000	19,000
Net cash used in financing activities	**(36,200)**	(94,500)	(156,900)
Net change in cash and cash equivalents	**17**	(16)	7
Cash and cash equivalents at beginning of year	**31**	47	40
Cash and cash equivalents at end of year	**$ 48**	$ 31	$ 47
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$ 27,196**	$ 28,704	$ 30,177
Partnership income taxes paid	**–**	2,153	2,417

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO FINANCIAL STATEMENTS

1. Description of Business

Great Lakes Gas Transmission Limited Partnership (the Partnership) is a Delaware limited partnership that owns and operates an interstate natural gas pipeline system. The Partnership transports natural gas for delivery to wholesale customers in the midwestern and northeastern United States (U.S.) and eastern Canada. The partners and partnership ownership percentages at December 31, 2013 and 2012 were as follows:

	Ownership percentage
General Partners:	
TransCanada GL, Inc.	46.45
TC GL Intermediate Limited Partnership	46.45
Limited Partner:	
Great Lakes Gas Transmission Company	7.10

Great Lakes Gas Transmission Company (the Company) and TransCanada GL, Inc. are wholly owned indirect subsidiaries of TransCanada Corporation (TransCanada). TC GL Intermediate Limited Partnership is a direct subsidiary of TC PipeLines, LP of which TransCanada indirectly owned a 33.3% interest prior to May 22, 2013. As a result of the closing of a common unit offering on May 22, 2013, TransCanada's indirect ownership interest in TC PipeLines, LP is now 28.9%.

2. Summary of Significant Accounting Policies

(a) Use of Estimates

The preparation of the financial statements in accordance with U.S. generally accepted accounting principles (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.

(b) Reclassifications

Prior year amounts have been reclassified where necessary to conform to the 2013 presentation.

(c) Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

(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 (NGA) 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. As of December 31, 2013 and 2012, there are no significant regulatory assets or liabilities reflected in these financial statements.

(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. Accounts charged to the allowance in 2013 and 2012 were not material to the Partnership's financial statements.

(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 affiliates. Imbalances owed to others are reported on the balance sheets as trade accounts payable or accounts payable to affiliates. 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 inventory consists of materials and supplies. The materials and supplies are valued at cost with cost determined using the average cost method.

(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. 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 FERC depreciation rates. Effective November 1, 2013 under a rate settlement approved by the FERC on November 14, 2013, the substantial portion of the Partnership's principal operating assets are being depreciated at an annual rate of 1.28%. The remaining assets are depreciated at annual rates ranging from 2.33% to 20.00%. Using these rates, the remaining depreciable life of these assets ranges from 3 to 46 years.

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 calculated 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. Capitalized AFUDC debt amounts are included as a reduction of interest and debt expense in the statements of income.

(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 primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For the Partnership's transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. For interruptible or volumetric-based services, the Partnership records revenues when physical deliveries of natural gas are made at the agreed-upon delivery point. The Partnership does not take ownership of the gas that it transports. The Partnership is subject to FERC regulations, and as a result, revenues the Partnership collects may be subject to refund in a rate proceeding. The Partnership establishes allowances for these potential refunds. As of December 31, 2013 and 2012, there are no allowances reflected in these financial statements.

(k) Commitments and Contingencies

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 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, 2013 and 2012. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

Other Contingencies

The Partnership recognizes liabilities for contingencies when it has an exposure that, when fully analyzed, indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, the Partnership accrues a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the lower end of the range is accrued.

(l) Income Taxes

During the years 2008 through 2011, the State of Michigan imposed a Michigan Business Tax (MBT) on partnerships. Effective for calendar years after 2011, the State of Michigan enacted legislation eliminating this MBT on partnerships and applied a more conventional income tax system taxing partners of partnerships. In addition, the new tax eliminated the gross receipts tax as well as property and other tax credits. The Partnership recorded a $5.2 million credit to deferred tax expense in 2011 to reflect the Michigan law changes. Income taxes, other than the MBT, are the responsibility of the partners and are not reflected in these financial statements.

3. Michigan Business Tax

Prior to 2012 the Partnership filed the MBT return on a combined basis with certain TransCanada affiliates. A tax payment agreement between the Partnership and TransCanada affiliates provided that the Partnership's MBT liability was determined as if a separate return was filed. Under the agreement, the Partnership remitted its current MBT liability to an affiliate. In 2012 the Partnership recorded an adjustment related to the 2011 return.

MBT for the years ended December 31, 2013, 2012, and 2011 consists of the following:

(In thousands)	**2013**	2012	2011
Current	**$–**	$(186)	$3,238
Deferred	**–**	–	(5,153)
	$–	$(186)	$(1,915)

The Partnership's MBT returns are open to audit under the statute of limitations for the 2008 through 2011 tax years. There are no uncertain tax positions related to the Partnership's MBT for the year ended December 31, 2011.

4. Commitments and Contingencies

(a) Legal Proceedings

The Partnership and its affiliates are named as defendants in legal proceedings that arise in the ordinary course of the Partnership's business. For each of the Partnership's legal matters, the Partnership evaluates the merits of the case, the Partnership's exposure to the matter, possible legal or settlement strategies, and the likelihood of an unfavorable outcome. If the Partnership determines that an unfavorable outcome is probable and can be estimated, the Partnership establishes the necessary accruals. As further information becomes available, or other relevant developments occur, the Partnership may accrue amounts accordingly. Based upon the Partnership's evaluation and experience to date, the Partnership had no accruals for its outstanding legal matters at December 31, 2013.

(b) Regulatory Matters

On November 14, 2013, the FERC approved a settlement the Partnership made with its customers to modify its transportation rates effective November 1, 2013. The settlement establishes maximum recourse transportation rates that are approximately 21% higher than pre-settlement rates. The settlement includes a moratorium on filing rate cases or challenging the settlement rates from November 1, 2013 to March 31, 2015 and requires that the Partnership file to have new rates in effect no later than January 1, 2018.

(c) Operating Leases

The Partnership leases office space under operating leases. Future minimum lease payments on the Partnership's operating leases as of December 31, 2013 were as follows (in thousands):

Year ending December 31:	
2014	$98
2015	99
2016	30
	$227

Rental expense on the Partnership's operating leases for the years ended December 31, 2013, 2012, and 2011 were $114 thousand, $99 thousand, and $90 thousand respectively.

(d) Other Commercial Commitments

The Partnership holds cancelable easements or rights-of-way arrangements from landowners permitting the use of land for the construction and operation of the Partnership's pipeline system. Currently, the Partnership's obligations under these easements are not material to its results of operations.

5. Long-Term Debt

The Partnership's long-term debt outstanding consisted of the following at December 31:

(In thousands)	**2013**	2012
6.73% series Senior Notes due 2014 to 2018	**$45,000**	54,000
9.09% series Senior Notes due 2014 to 2021	**80,000**	90,000
6.95% series Senior Notes due 2019 to 2028	**110,000**	110,000
8.08% series Senior Notes due 2021 to 2030	**100,000**	100,000
	335,000	354,000
Less current maturities	**19,000**	19,000
Total long-term debt less current maturities	**$316,000**	335,000

The aggregate annual required repayment of long-term debt is $19.0 million for each year from 2014 through 2018. Aggregate required repayments of long-term debt thereafter total $240.0 million.

The Partnership is required to comply with certain financial, operational, and legal covenants. Under the most restrictive covenants in the Senior Note Agreements, approximately $180.0 million of partners' capital was restricted as to distributions as of December 31, 2013. As of December 31, 2013, management of the Partnership believes the Partnership was in compliance with all of its financial covenants.

6. Fair Value Measurements

(a) Fair Value Hierarchy

Under FASB 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 following table presents the carrying amounts and estimated fair values of the Partnership's financial instruments that are measured on a recurring basis at December 31, 2013 and 2012. The fair value of a financial instrument is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

	2013		2012	
(In thousands)	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Financial assets:				
Cash and cash equivalents	**$48**	**48**	31	31
Financial liabilities:				
Long-term debt	**$335,000**	**410,114**	354,000	535,806

The following methods and assumptions were used to estimate the fair value of each class of financial instruments measured on a recurring basis:

Cash and cash equivalents – The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

Long-term debt – The fair value of senior notes 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. The Partnership presently intends to maintain the current schedule of maturities for the notes, which will result in no gains or losses on its repayment.

(c) Other Recurring Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of other items measured and recorded at fair value on a recurring basis as of December 31, 2013 and 2012:

	2013		2012	
(In thousands)	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Affiliate natural gas imbalance asset	**$3,302**	**$3,302**	3,480	3,480
Natural gas imbalance asset	**829**	**829**	761	761
Affiliate natural gas imbalance liability	**281**	**281**	1,083	1,083
Natural gas imbalance liability	**3,142**	**3,142**	834	834

Natural Gas Imbalances – 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. We value 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. We have classified the fair value of natural gas imbalances 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.

7. Transactions with Affiliated Companies

(a) Cash Management Program

The Partnership participates in TransCanada's cash management program, which matches short-term cash surpluses and needs of participating affiliates, 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 TransCanada at the rate of interest earned by TransCanada on its short-term cash investments. The Partnership pays interest on monies advanced from TransCanada based on TransCanada's short-term borrowing costs. At December 31, 2013 and 2012, the Partnership had a demand loan receivable from TransCanada of $21.9 million and $26.5 million, respectively.

(b) Affiliate Revenues and Expenses

The Partnership earns transportation revenues from TransCanada and its affiliates under contracts, some of which are provided at discounted rates and some at maximum recourse rates. The contracts are on the same terms as would be available to other shippers and the longest remaining term extends through 2032.

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 affiliates 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. In addition, the Partnership charges rent to affiliates for use of office space in Troy, Michigan.

The following table shows revenues and charges from the Partnerships' affiliates for the periods ended December 31:

(In thousands)	**2013**	2012	2011
Transportation revenues from affiliates	**$68,115**	77,338	80,553
Rental revenue from affiliates	**1,348**	1,355	1,316
Costs charged from affiliates	**31,273**	32,826	31,172

8. Distributions

The Partnership's distribution policy generally results in a quarterly cash distribution equal to 100% of distributable cash flow based upon earnings before income taxes, depreciation, and 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 9, 2014, the Management Committee of the Partnership declared a cash distribution in the amount of $11.8 million to the partners. The distribution was paid on February 3, 2014.

9. Subsequent Events

Subsequent events have been assessed through February 12, 2014, 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.

Glossary of Terms

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

2013 Acquisition	Acquisition of an additional 45 percent membership interest in each of GTN and Bison by the Partnership
2011 Acquisition	Acquisition from subsidiaries of TransCanada of a 25 percent membership interest in each of GTN and Bison
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
Bison	Bison Pipeline LLC
Carty Lateral	The proposed GTN lateral pipeline
Delaware Act	Delaware Revised Uniform Limited Partnership Act
DOT	U.S. Department of Transportation
Dth/day	Dekatherms per day
DSUs	Deferred Share Units
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fracking	Horizontal drilling in combination with multi-stage hydraulic fracturing
GAAP	U.S. generally accepted accounting principles
General Partner	TC PipeLines GP, Inc.
GHG	Greenhouse Gas
Great Lakes	Great Lakes Gas Transmission Limited Partnership
Great Lakes Rate Settlement	Stipulation and Agreement of Settlement for Great Lakes regarding its rates and terms and conditions of service
GTN	Gas Transmission Northwest LLC
GTN Settlement	Stipulation and Agreement of Settlement for GTN regarding its rates and terms and conditions of service
HCAs	High consequence areas
IDRs	Incentive Distribution Rights
IRS	Internal Revenue Service
KPMG	KPMG LLP
LDCs	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
Mainline	TransCanada's Mainline, a natural gas transmission system extending from the Alberta/Saskatchewan border east to Quebec
NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
Northern Border Settlement	Stipulation and Agreement of Settlement for Northern Border regarding its rates and conditions of service
NYSE	New York Stock Exchange

Other Pipes	GTN, Bison, North Baja and Tuscarora
Our pipeline systems/our pipelines	Our ownership interests in GTN, Northern Border, Bison, Great Lakes, North Baja and Tuscarora
Partnership	TC PipeLines, LP including its subsidiaries, as applicable
Partnership Agreement	Second Amended and Restated Agreement of Limited Partnership
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP's senior credit facility under revolving credit agreement as amended and restated, dated November 20, 2012
Term Loan Facility	TC PipeLines, LP's term loan credit facility under a term loan agreement dated July 1, 2013
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

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) and Tuscarora Gas Transmission Company (Tuscarora).

CORPORATE INFORMATION

BOARD OF DIRECTORS OF THE GENERAL PARTNER OF TC PIPELINES, LP

Karl Johannson
Chairman, TC PipeLines GP, Inc.
Executive Vice-President and President, Natural Gas Pipelines
TransCanada Corporation
Calgary, Alberta

Steven D. Becker
President and Director, TC PipeLines GP, Inc.
Vice-President, Business Development, Pipelines Division
TransCanada PipeLines Limited
Calgary, Alberta

Kristine L. Delkus
Executive Vice-President, General Counsel and
Chief Compliance Officer
TransCanada Corporation
Calgary, Alberta

Jack F. Jenkins-Stark (1)(2)(3)
Chief Financial Officer
Imergy Power Systems
Fremont, California

James (Jim) M. Baggs
Executive Vice-President, Operations and Engineering
TransCanada Corporation
Calgary, Alberta

Malyn K. Malquist (4)(5)
Retired Executive Vice-President and Chief Financial Officer
Avista Corporation
Spokane, Washington

Walentin (Val) Mirosh (3)(5)
President and Corporate Director
Mircan Resources Ltd.
Calgary, Alberta

(1) Lead Director
(2) Chair, Conflicts Committee
(3) Member, Audit Committee
(4) Chair, Audit Committee
(5) Member, Conflicts Committee

EXECUTIVE OFFICERS OF THE GENERAL PARTNER OF TC PIPELINES, LP

Karl Johannson
Chairman

Steven D. Becker
President

Stuart P. Kampel
Vice-President and General Manager

Sandra P. Ryan-Robinson
Principal Financial Officer and Controller

Terry C. Ofremchuk
Vice-President, Taxation

William C. (Chuck) Morris
Treasurer

Annie C. Belecki
Secretary

Jon A. Dobson
Assistant Secretary

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Left: As part of our commitment to pipeline integrity, TransCanada regularly inspects our pipeline systems.

TC PipeLines, LP

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