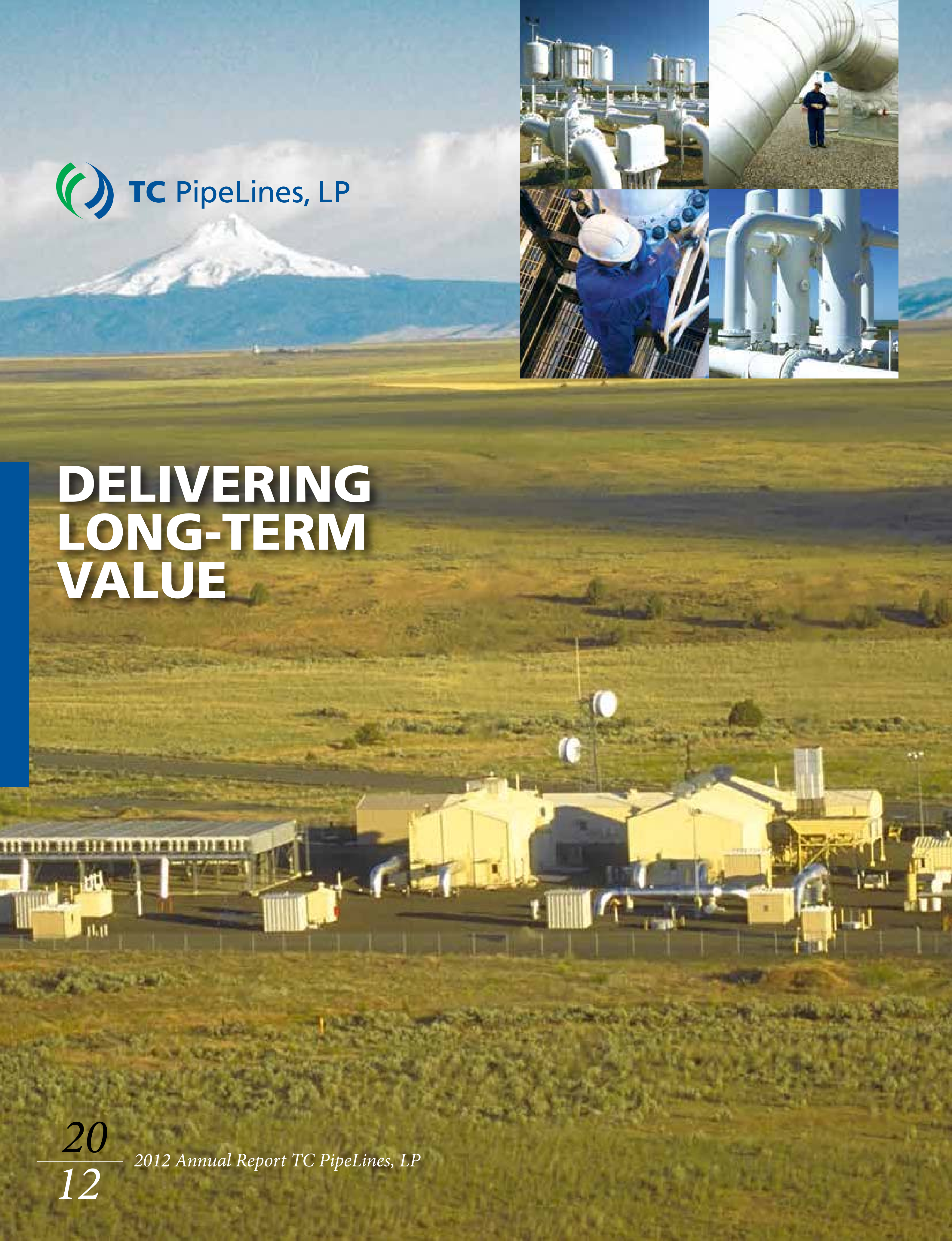

TC PipeLines, LP

DELIVERING LONG-TERM VALUE

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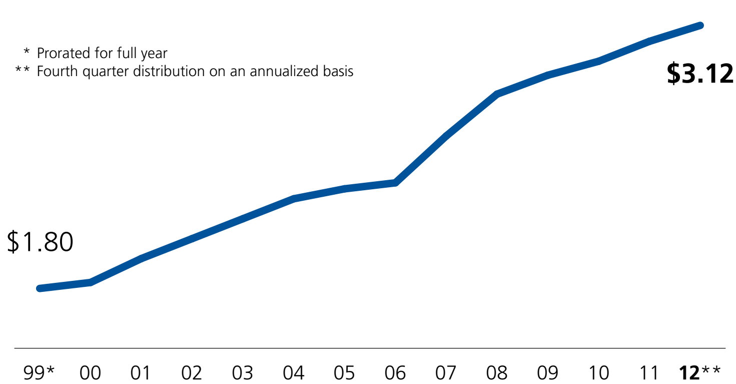
2012 Annual Report TC PipeLines, LP

2012 Financial Highlights

Year Ended December 31 (millions of dollars, except unit amounts)	2008(2)	2009(2)	2010	2011	2012
Cash Flow					
Partnership cash flows(1)	$ 144	150	180	222	202
Cash distributions paid	109	117	139	155	169
Income Statement					
Net income(2)	123	106	137	157	137
Balance Sheet					
Total assets(2)	1,701	1,675	1,651	2,082	1,998
Long-term debt (including current maturities)	537	541	514	742	688
Partners' equity	876	1,104	1,113	1,333	1,301
Common Units Statistics (per unit)					
Cash distributions paid	$2.775	$ 2.87	$ 2.94	$ 3.04	$ 3.10
Net income	$ 2.73	$ 2.34	$ 2.91	$ 3.02	$ 2.51
Common Units Outstanding (millions)					
Weighted average for the year	34.9	38.7	46.2	51.1	53.5
End of year	34.9	46.2	46.2	53.5	53.5

73% Growth in Annual Cash Distributions 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, 2012, filed with the Securities Exchange Commission (SEC).

(2) 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.

Steve Becker
President, TC PipeLines GP, Inc.

Letter to Unitholders

TC PipeLines' financial performance in 2012 was reflective of the quality of our pipeline investments and solid market fundamentals. The Partnership delivered growing distributions to unitholders as its infrastructure assets continued to provide essential linkages between natural gas supply basins and major North American markets.

With a focus on long-term value, recent rate case settlements create future toll stability and extend the economic life of our pipeline assets. Looking forward, the rebalancing of the natural gas industry and increasing growth of gas demand will continue to support the value and performance of our pipelines.

Year in review

The past year was characterized by shifting market dynamics as the natural gas industry experienced the warmest winter on record, increasing natural gas production and extremely narrow basis differentials. This resulted in unprecedented gas storage levels as well as changes in historical gas transportation patterns. Within this shifting landscape, our diversified asset portfolio generally performed well due to the long-term contractual structure of our business.

TC PipeLines' financial results reflect solid performance from the majority of our pipeline assets. Total cash flow generated was $202 million in 2012 on earnings of $137 million or $2.51 per common unit. These results were in-line with our expectations for 2012 given the known impact of the recent Gas Transmission Northwest (GTN) and Tuscarora rate cases and the associated tradeoff between lower short-term cash flow and longer-term value. While these new rate structures affected cash flow during the year, rate certainty ensures future stability and asset longevity. Similarly, we successfully negotiated a rate settlement with our Northern Border shippers which came into effect January 1, 2013. Our Great Lakes pipeline, however, experienced some challenges in 2012 as it transitions into a regional system serving gas storage needs and local markets. Revenue was negatively impacted as long-haul contracts were replaced by a smaller number of shorter-haul contracts at lower rates. Our remaining assets performed as anticipated with steady results year over year.

Unitholders continued to benefit from our prudent approach to managing our assets. In July, we increased the cash distributions paid to our unitholders by 1.3 percent to $0.78 per common unit per quarter. This marks the 13th consecutive year of cash distribution growth. Our conservative capital structure at 34 percent debt and our investment grade credit ratings (BBB/Baa2) from both S&P and Moody's ensure continued access to debt capital markets at competitive rates. Moreover, our five-year credit facility was extended to November 2017 with reduced pricing, a testament to our solid credit profile.

Partnership outlook

Looking forward, we will continue to focus on the long-term value and stability of our assets. In 2013, Partnership results will be impacted by Northern Border's rate settlement. We anticipate that the settlement will reduce cash flows from Northern Border, however it will not be required to change its rates until 2018. This will provide stability over the longer term. Northern Border remains a key pipeline in its market due to its connections to three major supply basins and its strategic footprint will continue to drive performance for the foreseeable future.

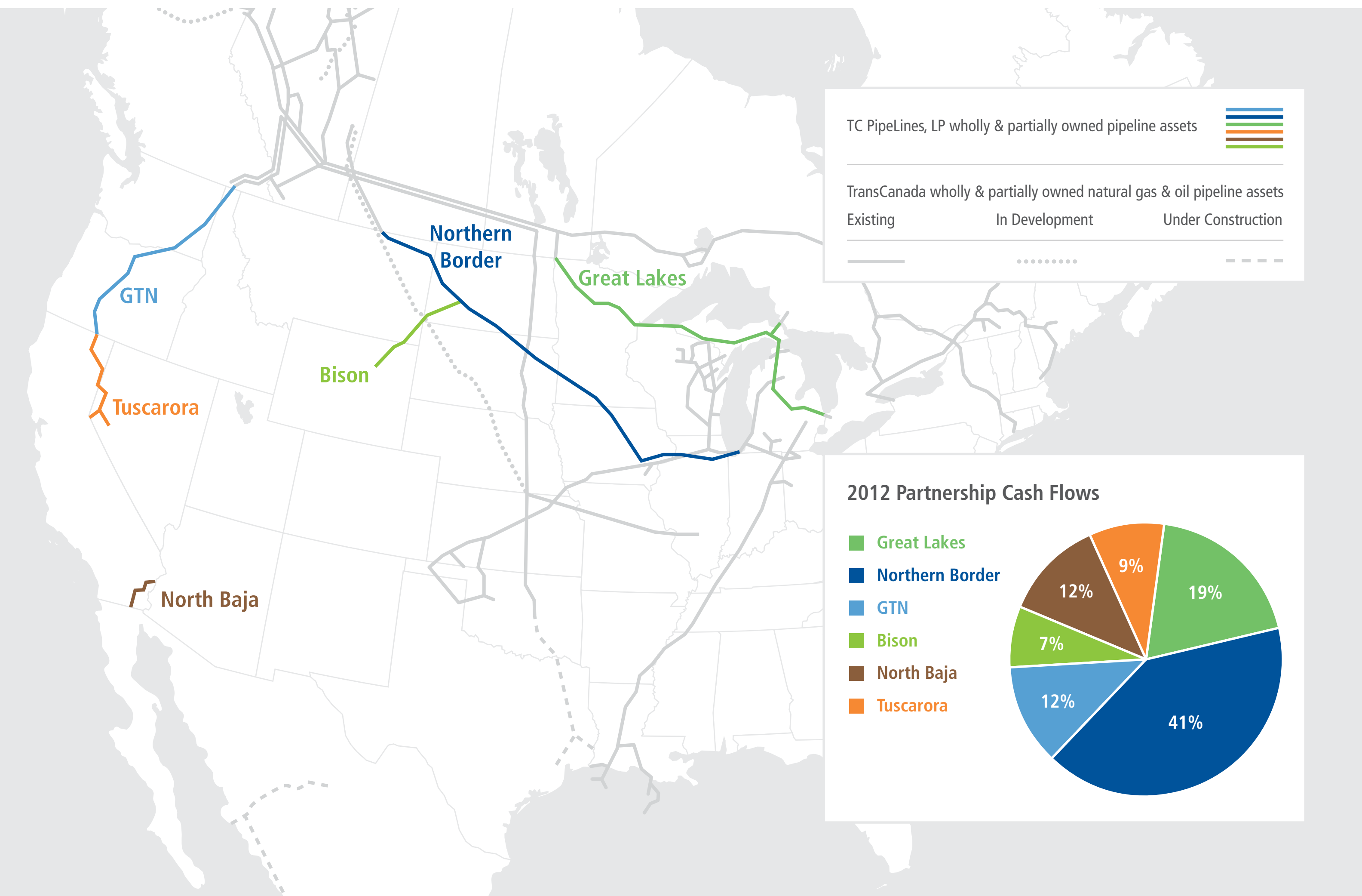
External factors influencing Great Lakes will also impact the Partnership's 2013 results as the North American natural gas industry rebalances and continues to evolve. The 2012/2013 winter season will be a significant driver of Great Lakes' earnings as a return to normal weather impacts gas storage withdrawals and transportation demand. Great Lakes' shift from a long-haul pipeline to a regional market and storage pipeline will also bring changes to contracts and revenue structure. Though Great Lakes experienced a decrease in revenue in 2012, its proximity to key gas storage fields positions it well for the long term as the natural gas market in North America finds a new equilibrium. The pipeline's upcoming rate case will provide Great Lakes an opportunity to reassess its rates to better reflect the new market dynamics and its changed flow patterns.

TC PipeLines' coming year will also be shaped by developments in the natural gas sector. Looking forward, we see growing strength in the North American natural gas industry. Ample supplies and low gas prices will drive significant increases in demand for natural gas in the electricity generation and industrial sectors. In the longer term, liquefied natural gas (LNG) exports will also bolster the strength of the industry. As demand grows and as capacity is rationalized through activities such as pipeline conversions, utilization of the North American pipeline grid will improve, leading to renewed demand for pipeline transportation services. Our general partner and sponsor TransCanada, continues to move forward with a sizable $25 billion capital program that extends through to the end of the decade. A program of this size will require a significant level of new financing and we remain a competitive source of capital to our sponsor.

I remain confident that our actions position us to deliver long-term value to our unitholders and I look forward to 2013 as a year of continued achievements and solid performance.

On behalf of TC PipeLines, LP

Steve Becker
President, TC PipeLines GP, Inc.



DELIVERING LONG-TERM VALUE

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 arrangements where payment is required, regardless of volume transported. This long-term, contract-based business model and stable asset base create sustainable value for our unitholders.

Essential infrastructure

Our pipelines are capable of transporting 8.9 Bcf/d of Canadian and U.S. natural gas, providing critical connections between growing supply basins and large demand regions. Our customers are primarily gas and electric utilities in California, the Pacific Northwest and the Midwest. A strong market position in these major centers provides access to both established supplies as well as important growth areas.

Our two largest assets are Northern Border and Great Lakes. Northern Border is linked to three key supply basins: the Western Canada Sedimentary Basin (WCSB), the Rockies Basin in Wyoming and the Bakken formation in North Dakota. Great Lakes provides access to vital storage fields in Michigan and Southwestern Ontario and serves important heating load areas in Michigan, Minnesota and Wisconsin. Natural gas storage is a critical factor in balancing gas flows as seasonal demands change. As such, Great Lakes is a critical regional pipeline which will continue to bring gas to demand centers over the longer term.

North American demand for natural gas is expected to rise by 15 Bcf/d by 2020 driven primarily by power generation, industrial growth and LNG exports. Our sponsor, TransCanada, continues to expand its gas transmission system in the WCSB and connect new gas supplies from shale as well as deep gas sources. TransCanada's Alberta system transports approximately 10 Bcf/d of natural gas, or approximately 70 percent of WCSB supply. TransCanada completed $650 million of upgrades and expansions in 2012 with over $2 billion planned for completion by 2015. TransCanada has also been selected to build the natural gas pipeline infrastructure for two proposed LNG facilities on Canada's west coast toward the end of the decade. This infrastructure will also be connected to the Alberta system. Northern Border, Great Lakes and GTN are well positioned to transport increased gas supplies as gas production ramps up in advance of these projects. In the longer term, this increasing production activity is anticipated to continue, thereby strengthening the productive capacity of the WCSB.

Enhanced stability; long-term focus

In 2012, Northern Border successfully negotiated a rate settlement with its shippers. Northern Border's depreciation rate was lowered, extending the economic life of the pipeline. While this reduces cash flows in the short term, it adds to the long-term value of the asset. Another important attribute of the settlement is that Northern Border will not be required to file for new rates until 2018. These settlement attributes are similar to the outcomes achieved for both GTN and Tuscarora in 2011. GTN is not required to file for new rates until 2016 and Tuscarora has no future obligation to file for new rates. These rate settlements create long-term stability in revenues and cash flow. Also in keeping with our focus on ensuring long-term stability, Great Lakes has begun activities toward a rate case process.

Strong industry sponsor; responsible stewardship

TransCanada has more than 60 years of experience and operating history and is a leader in the responsible development and reliable operation of North American energy infrastructure. With investments in natural gas pipelines and storage, oil pipelines and power generation, they provide us with industry insight and operating and management experience. We value our affiliation with TransCanada and consider it to be one of our key strengths.

TransCanada, our general partner, owns a 33 percent interest in the Partnership and operates all of our assets. TransCanada and TC PipeLines are strategically aligned to deliver long-term value. Our sponsor has a solid track record across North America in the areas of pipeline safety, environmental and governmental regulatory compliance and stakeholder engagement. TransCanada applies this extensive expertise and experience to the operation of our assets. Research and development activities at TransCanada are focused on improving the efficiency and safety of our operations in areas such as pipeline material and design, construction and environmental reclamation techniques, compressor performance and greenhouse gas emissions reduction. For the eleventh year in a row, TransCanada was named to the World Dow Jones Sustainability Index, a global index that tracks the performance of the leading sustainability-driven companies.

Financial strength

Our solid financial position is reflected by our investment grade credit ratings from both Standard & Poor's and Moody's (BBB/Baa2). Additionally, our lending group is strong and continues to be supportive, as evidenced by their recent extension of our five-year credit facility to November of 2017.

The current softness in the North American natural gas market, coupled with lower transportation rates on some of our assets, has reduced Partnership cash flow and cash distribution coverage compared to prior years. Our assets remain critical to the markets that they serve and we expect our assets to continue to perform well over time as they adjust to changing market dynamics. The outcomes of our recent rate case settlements will lessen the impact of depreciation on rate bases, maintaining long-term value. Our strong financial position and conservative capital structure afford ample flexibility and liquidity, providing access to capital markets. Moreover, our low general partner incentive distribution rights, currently set at two percent, add to our competitive position and allow us to capitalize on potential growth opportunities.

Financial performance

The Partnership's financial performance is supported by the quality of our pipeline investments and solid market fundamentals. In 2012, the annual distribution was increased for the 13th consecutive year, pointing to our track record of prudent management. Quarterly cash distributions increased 1.3 percent to $0.78 per unit. The Partnership paid $169 million in distributions and generated Partnership cash flow of $200 million.

Future opportunities

The current scope of change that is shaping North America's energy landscape is unparalleled in recent history. Advanced technology is unlocking substantial oil and natural gas reserves once thought to be economically inaccessible. North America's drive toward energy independence is creating an ever-expanding need for continued resource development.

The infrastructure required to support this growth presents a sizable opportunity for large, well capitalized companies. Our sponsor, TransCanada, is particularly well positioned. Since 2010, TransCanada has placed $13 billion of new projects into service, including the first phase of the Keystone oil pipeline. An additional $25 billion of projects are in process for completion through to the end of the decade. This substantial capital program will entail a similarly large financing program and TC PipeLines is one avenue through which our sponsor can access the required funding.

In addition to opportunities through TransCanada, we actively consider third-party acquisitions and organic expansion projects. We remain opportunistic, but most importantly, disciplined in our approach to potential transactions. Our focus is to deliver long-term value and cash flow predictability, providing sustainable cash distributions to our unitholders.

Our GTN right-of-way in Palouse country in Eastern Washington demonstrates our commitment to ensuring that any land disturbed by pipeline construction is fully restored.

Our pipelines are expertly managed and have a solid track record of pipeline safety across North America.

TC PIPELINES, LP

TABLE OF CONTENTS

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

PART I

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

This report includes certain forward-looking statements 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 to differ materially from those contemplated in forward-looking statements include, but are not limited to:

- the ability to grow distributions through accretive expansions or acquisitions;
- 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 United States of America (U.S.);
  - competition from other pipeline systems;
  - natural gas storage levels;
  - the level of production of natural gas liquids and the subsequent impact on relative competitiveness of natural gas producing basins; and
  - rates and terms of service;
- 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), U.S. Department of Transportation (DOT) and U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA);
- the outcome and frequency of rate proceedings on our pipeline systems;
- our ability to identify and complete expansion projects and other accretive growth opportunities;
- the performance by the shippers of their contractual obligations on our pipeline systems;
- changes in the taxation of master limited partnership investments by states or the federal government such as the elimination of pass-through taxation or tax deferred distributions;
- potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner) its affiliates 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
- unfavorable economic conditions and the impact on capital markets.

These and other risks are described in greater detail in Part II, 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 33.3 percent equity interest in us, including a 31.3 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 2012, we increased our quarterly cash distribution by 1.3 percent to $0.78 per common unit and during fiscal year 2012, we paid cash distributions of $3.10 per common unit. On February 14, 2013, we paid a cash distribution of $0.78 per common unit for the fourth quarter of 2012.

Great Lakes – On October 31, 2012, a number of long-haul capacity contracts expired on the Great Lakes system. Great Lakes re-contracted a portion of this capacity on a shorter-term, short-haul basis. These contracts are indicative of the current industry trend towards short-term contract renewals and the changing dynamics for the Great Lakes pipeline system from a west to east conduit pipeline to a more regional pipeline.

Northern Border Rate Settlement – In January 2013, FERC gave final approval for Northern Border's settlement with shippers on transportation rates and other terms of service (Northern Border Settlement) effective January 1, 2013. See "Government Regulation – Rate Proceedings" for more information.

Tuscarora Rate Settlement – On March 9, 2012, Tuscarora received FERC approval of its settlement regarding its rates and terms and conditions of service (Tuscarora Settlement) effective January 1, 2012. See "Government Regulation – Rate Proceedings" for more information.

Business Strategies

- Our strategic approach 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 for rates, which may include mutually beneficial performance incentives. The regulator must approve the components of any settlement.

Contracting
New pipeline projects are typically supported by long-term contracts. The term (in years) of contracts required by a developer for a new pipeline is dependent on the individual developer's appetite for risk and is a function of expected rates of return and stability or 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. Significant producing regions in North America include the Gulf of Mexico, Western Canada Sedimentary Basin (WCSB), Mid-Continent, Rockies, Appalachian Basin, Permian Basin and San Juan Basin. Recent increases in the development of shale and other unconventional gas reserves have resulted in increases in overall North American natural gas production and increased reserves.

There has been an increase in the number of significant supply basins to serve the North American market. The development of shale gas reserves that are located close to traditional existing markets, particularly in the Northeastern U.S., has led to an increase in the number of supply choices and is changing traditional 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
- these technologies are also being applied 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, increases 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 – the current low prices in North America may slow drilling activities that in turn diminishes 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 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.

This trend is expected to continue.

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 and demand have resulted in growing pipeline infrastructure and increased competition for transportation service throughout North America. More pipeline capacity was added to the continental pipeline network between 2008 and 2011 than in any comparable period in history, and natural gas supply areas that were once constrained, like the U.S. Rockies and east Texas, now have several paths to reach markets. The increase in capacity from new pipeline infrastructure has caused regional basis differentials, which is the difference in market prices paid for natural gas between different natural gas receipt and delivery points, to shrink. Basis differentials have generally declined in the U.S. over the past few years which indicates the value of pipeline transportation has also, generally, decreased. Construction of new pipeline infrastructure has slowed and is currently focused on regional debottlenecking.

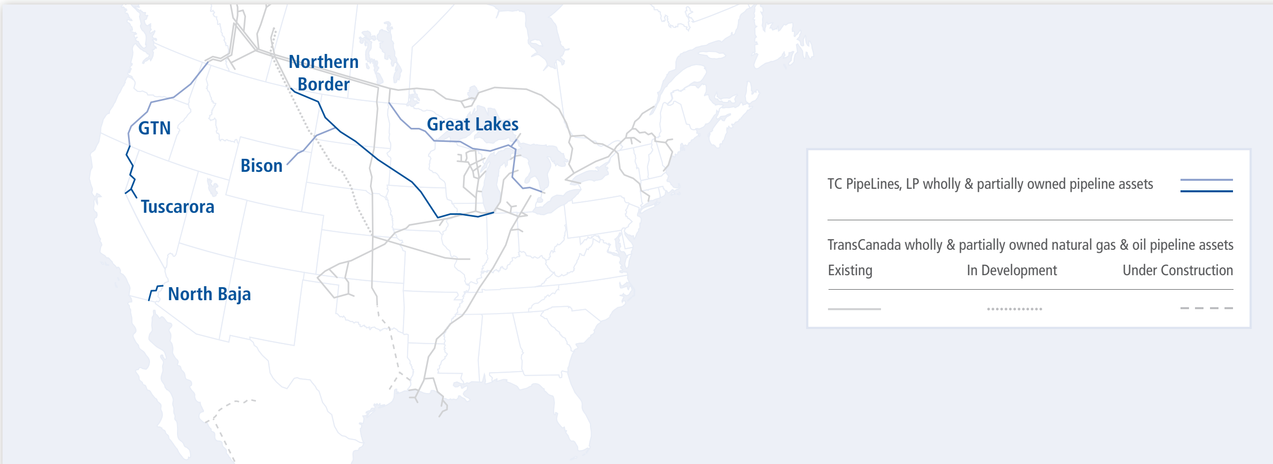
Our Pipeline Systems

We have equity ownership interests in four natural gas interstate pipeline systems that are accounted for on an equity basis and two wholly-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. and Central Canada. All of our pipeline systems are operated by subsidiaries of TransCanada.

Our pipeline systems include:

Pipeline	Length	Description	Ownership
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%
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 Rockies Basin. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50%
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. TransCanada owns the remaining 75 percent of GTN.	25%
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 75 percent of Bison.	25%
North Baja	86 miles	Extends between an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona to an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border. North Baja is a bi-directional pipeline.	100%
Tuscarora	305 miles	Extends between GTN 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. 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.

Great Lakes – The composition of Great Lakes' revenue has substantially shifted to shorter-term, short-haul and bidirectional transportation. This shift reflects ongoing changes in supply, particularly growth of supply in Great Lakes' traditional market area, demand and infrastructure fundamentals across the North American natural gas market and the expiration of long-term, long-haul contracts. Therefore, Great Lakes' revenues are not substantially supported by long-term contracts. 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 in 2013, levels of natural gas in storage and the price of natural gas liquids and the associated impact to North American natural gas production. 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 and Michigan.

Northern Border – Northern Border's revenues are substantially supported by firm transportation contracts through March 2014. As contracts expired in 2012, 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.

GTN – GTN's revenues are substantially supported by long-term contracts. Contracts expiring prior to 2023 are primarily held by LDCs. 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.

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

For the year ended December 31, 2012, no single customer accounted for more than ten percent of our proportionate share of our pipeline systems' operating revenues.

Competition

Four of our pipeline systems, Great Lakes, Northern Border, GTN 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. Great Lakes, Northern Border 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 Rockies Basin.

To the extent our pipeline systems are contracted, they are less vulnerable to competitive factors such as those discussed above. When their contracts expire, the value of their transportation services will be impacted by competitive pressures.

Relationship with TransCanada

TransCanada is the indirect parent of our General Partner and owns, through its subsidiaries, an approximate 33.3 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 $48 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, 2,154 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 II, 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 give 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.

Rate Proceedings
Great Lakes – Great Lakes has a FERC-approved rate settlement in place. It can file for new rates at any time, but must file no later than November 2013.

Northern Border – In January 2013, FERC gave final approval for Northern Border's settlement with shippers on transportation rates and other terms of service. With this approval, Northern Border's transportation rates were reduced by approximately 11 percent effective January 1, 2013. In addition, the composite depreciation rate was reduced to 2.19 percent from 2.40 percent. 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.

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.

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.

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.

Tuscarora – Tuscarora received approval from FERC on March 9, 2012 of its settlement agreement with shippers. The settlement includes three-year contract extensions to the term of a number of contracts with Tuscarora's largest customer, provided for new rates effective January 1, 2012, and a moratorium on the filing of future rate proceedings until December 31, 2014.

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 generate hazardous waste that 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 the use of federal lands.
- *The Endangered Species Act (ESA)* – The ESA restricted 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.

Emissions Regulation

Substantial uncertainty exists regarding the impact of new and proposed greenhouse gas (GHG) laws and regulations. In California, the Assembly Bill 32 Cap and Trade Program took effect on January 1, 2013. Our facilities do not meet the GHG emission threshold and are excluded from the program. 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. Because of the uncertainty of policy and regulatory schemes, the future effects on our pipeline systems cannot be predicted.

Safety

Our pipeline systems are affected by existing and proposed pipeline safety regulations administered by PHMSA with respect to pipeline design, installation, testing, construction, operation, replacement and integrity management.

The Pipeline Safety Improvement Act of 2002, as amended, (Pipeline Safety Act) requires pipeline companies to perform baseline integrity assessments on pipeline segments that traverse densely populated areas or near sites that are specifically designated as high consequence areas (HCAs). On December 29, 2006, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, referred to as PIPES of 2006, was enacted, which further amended the Pipeline Safety Act. Pipeline companies are required to perform the baseline integrity assessments within ten years of the date of enactment and perform reassessments on a seven-year cycle. HCAs make up a small percentage of our pipeline systems in which we are fully compliant with the Pipeline Safety Act. In addition to complying with the Pipeline Safety Act, our Integrity Management Program (IMP) is applied annually to our pipelines.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Act) was enacted. The 2011 Pipeline Act reauthorized and amended the previous PIPES Act of 2006 and Pipeline Safety Act. The 2011 Pipeline Act reauthorizes the PHMSA federal pipeline safety programs through fiscal year 2015 and includes a number of additional provisions affecting pipeline owners and operators. Items that may have a material effect on pipeline owners and operators include increases to the cap on civil penalties for violators of pipeline regulations and additional civil penalties for obstructing investigations; a directive for PHMSA to develop regulations requiring the installation of automatic or remote control shut off valves for new or replaced transmission pipelines; a directive for PHMSA to establish requirements for natural gas transmission pipeline operators to confirm the physical and operational characteristics and their maximum allowable operating pressure (MAOP) for pipelines in more populated areas (class 3 and 4 locations) and HCAs; a directive that PHMSA issue regulations requiring natural gas transmission pipeline operators to report to PHMSA any pipeline segments with insufficient MAOP records; and a requirement that PHMSA issue regulations on testing of grandfathered or previously untested natural gas transmission pipelines.

PHMSA and the Comptroller General are also required by the 2011 Pipeline Act to conduct several studies and develop several reports by 2013, some of which are a necessary prelude to additional rulemaking. These studies include a study on expanding IMP requirements outside of HCAs, and possibly eliminating class location requirements, as well as a report to Congress on using risk based Assessment Intervals for IMP. These studies are in progress and may result in regulatory changes. No regulatory changes are expected prior to 2014 as a result of these studies.

In addition, there are various other ongoing legislative and regulatory measures proposed at the federal and state levels to increase pipeline safety. These legislative and regulatory policies, if enacted, may impact our pipeline systems, as well as other pipelines in the industry. While we believe that our pipeline systems are in substantial compliance with current applicable requirements, due to the possibility of enactment of these new or amended laws and regulations, 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, results of operations and cash flows.

EMPLOYEES

We do not have any employees. We are managed by our General Partner. Subsidiaries of TransCanada operate our pipeline 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 OUR PIPELINE SYSTEMS

Our pipeline systems may not be able to renew or replace expiring transportation contracts or do so at favorable rates or for a long term.

The value of our transportation services depends on a shipper's demand for pipeline capacity and the price paid for that capacity. Excess pipeline capacity may lead to an inability of our pipelines to charge maximum rates, and may drive customers' decisions with respect to contracting for capacity.

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 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 or on any terms 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.

Great Lakes has been negatively impacted by the factors described above, particularly by the growth of supply in Great Lakes' traditional market area. Great Lakes has a considerable portion of its available capacity unsold and its contract portfolio has transitioned from being comprised primarily of long-term, long-haul contracts to now being comprised primarily of shorter-term, short-haul contracts. Although our other pipelines generally have longer-term contract portfolios, over the medium to long term, they are also subject to the factors described above.

The long-term financial condition of Great Lakes, Northern Border and GTN is largely dependent on the continued availability of and demand for natural gas from the WCSB.

As the long-term contracts on our pipeline systems expire, the demand for transportation service on some of our pipeline systems will depend in large part on the availability of supply of natural gas available for export from the WCSB. Natural gas available for export from the WCSB depends on numerous factors, including the demand for natural gas within Western Canada, WCSB natural gas production, the availability of storage and natural gas prices. Western Canadian demand for natural gas is expected to continue to increase primarily as a result of oil sands development and natural gas fired electric power generation. In addition, there are a number of pipelines and related LNG export terminal proposals along the British Columbia, Canada west coast that, if constructed, would source natural gas from the WCSB beginning in the latter half of the decade. Unless there is a corresponding increase in the amount of natural gas production in the WCSB to meet this growing demand, there could be diminished natural gas volumes available for export from the WCSB.

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.

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 likely decline.

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

Although no one customer represents greater than ten percent of our revenues, 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 our customers are unable to pay for our services. If a significant customer has credit or 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. In addition, as contracts expire, the failure of any of our customers could also result in the non-renewal of contracted capacity, which could have a material adverse effect on our business and results of operations.

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; and damage to a pipeline by a third party; 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.

Our pipeline systems may experience significant costs and liabilities related to pipeline integrity testing programs and any necessary pipeline repairs, or preventative or remedial measures may cause significant costs and liabilities.

The DOT and PHMSA have adopted regulations that 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 pipeline as necessary and implement preventative and mitigating actions.

The results 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 the DOT and PHMSA regulations could subject our pipeline systems to penalties and fines.

To the extent not recoverable through rates, the cost of additional integrity management requirements to our pipeline systems could have a material adverse effect on our results of operations or financial position and our ability to maintain current distribution levels.

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 are 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.

Under certain environmental laws and regulations, we may be exposed to substantial liabilities for pollution 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.

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 pipeline cannot be predicted.

Our pipeline systems are subject to pipeline safety laws and regulations, compliance with which can require significant expenditures, may increase our cost of operations and may affect or limit our business plans.

Our pipeline systems are subject to pipeline safety regulations administered by PHMSA. These laws and regulations require our pipeline systems to comply with design, construction, maintenance and operation requirements, including monitoring and maintaining their integrity. Pipeline failures or failure to comply with applicable regulations could result in the interruption of operations or in the reduction of allowable operating pressures which would reduce available capacity on our pipeline systems.

Should any of these risks materialize, it could have a material adverse effect on our operations, financial condition, results of operations and cash flows.

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

As of December 31, 2012, Great Lakes, Northern Border, GTN and Tuscarora had $354 million, $473 million, $325 and $27 million of debt outstanding, respectively. Of the debt outstanding, Great Lakes and Tuscarora have $19 million and $3 million of debt maturing in 2013, respectively. Our pipeline systems' respective debt levels could have negative consequences to each of them, 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, some of which are beyond their control.

In addition, under the terms of these financing arrangements, our pipeline systems are prohibited from making cash distributions during an event of default under their debt instruments. Under Great Lakes' debt instruments, Great Lakes has limitations on the level of indebtedness and has other restrictions, including a general prohibition against liens on pipeline facilities. Provisions in Northern Border's debt instruments limit its ability to incur indebtedness and engage in specific transactions. This could reduce its ability to capitalize on business opportunities that arise in the course of its business. GTN's debt provisions contain limitations on debt secured by liens and sale-leaseback transactions, as well as restrictions on GTN's debt to capitalization ratio. Under Tuscarora's debt instruments, Tuscarora is granted a security interest in its transportation contracts which is available to noteholders upon an event of default.

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 THE PARTNERSHIP

Our indebtedness may limit our ability to obtain additional financing, make distributions or pursue business opportunities.

As of December 31, 2012, the Partnership had $688 million of debt outstanding, including the revolving credit facility and Senior Notes. This level of 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, some 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.

We are required by GAAP to evaluate our equity investments, long-lived assets and goodwill for impairment on an annual basis or whenever events or circumstances indicate that the carrying value may not be recoverable. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment 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 considers 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 an 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, 2012, we determined that the fair values of our equity investments, long-lived assets and goodwill were higher than their carrying values. As the composition of Great Lakes' revenue has shifted from long-term contracts to shorter-term and short-haul transportation, there is an increased risk that adverse changes in key assumptions could result in a future impairment of our equity investment in Great Lakes.

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.

We do not own a controlling interest in Great Lakes, Northern Border, GTN or Bison, which limits our ability to control these assets.

We do not own a controlling interest in Great Lakes, Northern Border, GTN or Bison 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.

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 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 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.

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, 2012, $312 million of our total $688 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.

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

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. The ownership of an aggregate of approximately 31 percent of the outstanding common units by our General Partner and its affiliates 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 will 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, 2012, the General Partner and its affiliates own approximately 31.3 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 and may be substantial 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, 2012, we paid fees and reimbursements to our General Partner in the amount of $3 million (2011 – $2 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 federal income tax purposes. The Internal Revenue Service (IRS) could treat us as a corporation, which would substantially reduce the cash available for distribution to unitholders.

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 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 would generally be taxed again to unitholders as corporate distributions, and no income, gains, losses, deductions or credits would flow through to unitholders. Because a tax would be imposed upon us as an entity, the cash available for distribution to unitholders would be substantially reduced. Our treatment 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.

Current laws may change so as to cause us to be taxable as a corporation for federal income tax purposes or otherwise to be subject to entity level taxation. Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for 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.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present 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. Any modification to the federal income tax law or interpretations thereof could make it difficult or impossible to meet the requirements for us to be treated as a partnership for federal income tax purposes. These modifications could cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units. We are unable to predict whether or not such changes, if any, will ultimately occur. Any modifications to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively affect the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

If our pipeline systems were to become subject to a material amount of entity-level taxation for state tax purposes, then our pipeline systems' operating cash flow and cash available for distribution to us and for other business needs would be reduced.

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 to entity level taxation. Imposition of such taxes on our pipeline systems will reduce the cash available for distribution to us and for other business needs by our pipeline systems, and adversely affect the amount of funds available for distribution to our unitholders.

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 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 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 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 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 potential recapture of items such as 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, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

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 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. 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.

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 Bureau of Indian Affairs (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.

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 Fort Peck Tribal Executive Board on behalf of the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. 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. Most of the allotted lands are subject to a perpetual easement granted by the BIA for and on behalf of the individual allottees or obtained through condemnation. Several tracts are subject to a right-of-way grant that expires in 2015.

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 Northern Border and Tuscarora rate proceedings described in Item 1. "Business – Government Regulation – FERC Rate Proceedings" is incorporated herein by reference. We are also a party to the following legal proceedings:

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 contract. The proceeding relates to a transportation service agreement executed in September 2006 pursuant to which Great Lakes agreed to transport natural gas on a firm basis to a yet-to-be constructed facility of Essar for a term that started on July 1, 2009 and ends on March 31, 2024. Essar has refused to honor its contractual obligations, in particular required monthly payments. Great Lakes seeks to recover approximately $33 million for past and future payments due under the agreement. On May 25, 2010, Essar filed a counterclaim against Great Lakes and third party claims against the Partnership and several affiliates seeking a declaratory judgment delaying Essar's duty to perform under the agreement until the Essar facility is constructed and ready to accept delivery of natural gas. Essar also seeks recovery of approximately $580,000 drawn by Great Lakes under a letter of credit based on a claim of conversion. Depositions are almost concluded and a trial is expected to be scheduled for late 2013 or early 2014. On November 27, 2012, Essar filed a compliant at FERC duplicating its defenses and arguments in the federal court proceeding as a violation of Section 5 of the Natural Gas Act. Great Lakes filed its response in the FERC proceeding and moved for dismissal by FERC.

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. Northern Border recorded a liability of $9 million, including interest, in 2011 related to this matter. 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 Northern Border is currently awaiting a decision.

EPA Request for Information under CAA – By letter dated December 28, 2009, the EPA required Great Lakes to provide information regarding its natural gas compressor stations in the states of Minnesota, Wisconsin and Michigan as part of the EPA's investigation of Great Lakes compliance with the CAA. On May 28, 2010, Great Lakes submitted its response to the EPA and subsequently responded to a request from the EPA dated July 26, 2010 on information regarding one natural gas compressor station located in Minnesota. In May 2011, the EPA required Great Lakes to provide additional information regarding a natural gas compressor station located in Minnesota, as well as information regarding other natural gas compressor stations in the states of Minnesota and Michigan. The potential effects on Great Lakes that may arise as a result of this information request or the underlying compliance review are not determinable at this time.

Item 4. Mine Safety Disclosure

None.

PART II

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

As of February 20, 2013, there were 61 registered holders of common units and approximately 31,748 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 (NASDAQ).

We currently have 53,472,766 common units outstanding, of which 36,387,935 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 NASDAQ, as applicable, 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		Cash Distributions Declared per Common Unit
	High	Low	
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**
2011			
First Quarter	$54.95	$50.02	$0.75
Second Quarter	$52.55	$43.24	$0.77
Third Quarter	$49.04	$39.24	$0.77
Fourth Quarter	$48.36	$41.61	$0.77

On February 14, 2013, we paid a cash distribution of $43 million to unitholders and the General Partner, representing a cash distribution of $0.78 per common unit for the quarter ended December 31, 2012. The distribution was allocated in the following manner: $42 million to the unitholders as of the close of business on January 29, 2013 (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 2012, the Partnership made cash distributions to unitholders and the General Partner that amounted to $169 million compared to $155 million in 2011.

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 2012 and 2011, 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)	**2012**	2011[(a)]	2010	2009[(b)]	2008[(b)]
Income Data (for the year ended December 31)					
Equity earnings from unconsolidated affiliates	**129**	154	126	99	123
Transmission revenues	**65**	70	69	68	65
Net income	**137**	157	137	106	123
Basic and diluted net income per common unit	**$2.51**	$3.02	$2.91	$2.34	$2.73
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$3.110**	$3.060	$2.960	$2.895	$2.815
Balance Sheet Data (at December 31)					
Total assets	**1,998**	2,082	1,651	1,675	1,701
Long-term debt (including current maturities)	**688**	742	514	541	537
Partners' equity	**1,301**	1,333	1,113	1,104	876

(a) 2011 net income includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

(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.

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 $137 million or $2.51 per unit in 2012 compared to $157 million or $3.02 per unit in 2011. Cash distributions paid increased nine percent to $169 million while Partnership cash flows decreased ten percent to $202 million. Our cash distribution coverage ratio was 1.21 times in 2012.

On March 9, 2012, Tuscarora received FERC approval of the Tuscarora Settlement effective January 1, 2012. Compared to 2011, the Tuscarora Settlement reduced Tuscarora's revenue by $6 million in 2012. Net income was reduced by $3 million as a result of the lower revenue offset by lower depreciation expense.

During 2012, Great Lakes' long-haul capacity was sold mostly under short-term contracts and at lower rates and volumes compared to the same periods in 2011 resulting in transmission revenues being $68 million lower in 2012. This resulted in a $33 million reduction to the Partnership's equity earnings and $29 million lower cash distributions from Great Lakes in 2012 compared to 2011.

In January 2013, FERC gave final approval of the Northern Border Settlement effective January 1, 2013. The Northern Border Settlement establishes maximum long-term transportation rates and charges on the Northern Border system. Northern Border's reservation rates were reduced by approximately 11 percent.

Outlook of Our Business

Our pipelines' operating results and our financial position, including the value of our related equity investments, will be impacted by the expiration of long-term contracts, competition for supply, transportation rates charged, and decisions regarding rate proceedings that affect rates in 2013 and beyond.

Great Lakes operates under a rate settlement approved by FERC in July 2010 and is required to file a NGA Section 4 general rate case or reach a settlement on or before November 1, 2013. This could impact the rates charged by Great Lakes in 2014 and beyond.

As a result of the shift in contracting from long-term, long-haul contracts to short-term, short-haul and bi-directional contracts and other changing market factors affecting Great Lakes, the amount of Great Lakes' revenue in 2013 will be more dependent on its ability to sell available capacity on a short-term basis than in prior years and is therefore highly variable.

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, the outcome of its NGA Section 4 rate case and the outcome of the TransCanada Mainline regulatory hearing with the Canadian National Energy Board relating to services and tolls on that system. The outcome of these factors is uncertain and, therefore, the impact to Great Lakes and the Partnership are not estimable with any reasonable certainty. If the aggregate of these factors is not favorable to Great Lakes, however, equity earnings in 2013 from Great Lakes could be significantly lower than in 2012.

Based on the current contracted capacity that will be directly impacted by the lower transportation rates and a lower composite depreciation rate under the Northern Border Settlement, the Partnership's share of equity earnings in 2013 is expected to be reduced by approximately $10 million and the Partnership's cash flows in 2013 are expected to be reduced by approximately $10 million, as compared to 2012. Actual results from Northern Border will depend on a number of other factors.

GTN, Bison, North Baja and Tuscarora are expected to provide relatively stable revenues.

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. Partnership cash flows include cash distributions from the Partnership's equity investments, Great Lakes, Northern Border, GTN and Bison plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja and Tuscarora, net of Partnership costs and distributions declared to the General Partner. 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 Great Lakes, Northern Border, GTN and Bison, and ownership of North Baja and Tuscarora were our only material sources of income in 2012. Therefore, our results of operations and Partnership cash flows were influenced by, and reflect the same factors that influenced, the financial results of Great Lakes, Northern Border, GTN, Bison, North Baja and Tuscarora. 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 in this format to enhance investors' understanding of the way management analyzes our financial performance. We believe this summary provides a more meaningful comparison of our net income to prior years, as we account for our partially-owned pipeline systems using the equity method. 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)	**2012**	2011	2010
Equity earnings:			
Great Lakes	**27**	60	59
Northern Border	**72**	75	67
GTN[(a)]	**19**	12	–
Bison[(a)]	**11**	7	–
Net income from Other Pipes[(b)]	**36**	40	37
Partnership expenses	**(28)**	(37)	(26)
Net income	**137**	157	137

(a) 25 percent interests in each of GTN and Bison were acquired in May 2011.

(b) "Other Pipes" includes the results of North Baja and Tuscarora.

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

Net income decreased $20 million to $137 million in 2012 compared to $157 million in 2011. This decrease was primarily due to lower equity earnings from Great Lakes, partially offset by a full year of earnings from GTN and Bison and 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 GTN and Bison acquisitions, as well as a decrease in financial charges resulting from a lower average debt balance and the use of floating rate debt in 2012.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

Net income increased $20 million to $157 million in 2011 compared to $137 million in 2010. This increase was primarily due to higher equity earnings from Northern Border, earnings from the 25 percent membership interests in GTN and Bison, which were acquired in May 2011, partially offset by higher Partnership expenses.

Equity earnings from Northern Border were $75 million in 2011, an increase of $8 million compared to 2010. The increase in equity earnings was primarily due to increased revenue from transportation sales.

Costs at the Partnership level increased $11 million to $37 million in 2011 compared to 2010. The increase was primarily due to costs incurred relating to the GTN and Bison acquisitions along with higher financial charges in 2011 resulting from higher average debt outstanding.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity include distributions received from our investments in unconsolidated affiliates, operating cash flows from North Baja and Tuscarora, public offerings of debt and equity 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.

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 although limited by FERC, which allow them to request credit support as circumstances dictate.

Our cash flow is based on the distributions from our portfolio of six pipelines. Reduced transportation revenue on Great Lakes is expected to result in lower and more volatile cash flow from Great Lakes than in prior years. 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 at the Partnership level over the next 12 months, including our distributions, utilizing our cash flow and our existing Senior Credit Facility as 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.

The Partnership calculates Partnership cash flows as net income plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja and Tuscarora, and cash distributions received in excess of equity earnings from the Partnership's equity investments in Great Lakes, Northern Border, GTN and Bison, net of distributions declared to the General Partner. Partnership cash flows before General Partner distributions represent Partnership cash flows prior to distributions declared 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 to Partnership Cash Flows

Year Ended December 31 *(millions of dollars except per common unit amounts)*	**2012**	2011	2010
Net income[a]	**137**	157	137
Add:			
Cash distributions from Great Lakes[b]	**44**	73	69
Cash distributions from Northern Border[b]	**96**	99	86
Cash distributions from GTN[a][b]	**28**	33	–
Cash distributions from Bison[a][b]	**16**	6	–
Cash flows provided by Other Pipes' operating activities	**49**	52	54
	233	263	209
Less:			
Equity earnings from unconsolidated affiliates	**(129)**	(154)	(126)
Other Pipes' net income	**(36)**	(41)	(37)
	(165)	(195)	(163)
Partnership cash flows before General Partner distributions	**205**	225	183
General Partner distributions[c]	**(3)**	(3)	(3)
Partnership cash flows	**202**	222	180
Cash distributions declared	**(170)**	(161)	(140)
Cash distributions declared per common unit[d]	**$3.11**	$3.06	$2.96
Cash distributions paid	**(169)**	(155)	(139)
Cash distributions paid per common unit[d]	**$3.10**	$3.04	$2.94

[a] 25 percent interests in each of GTN and Bison were acquired in May 2011.

[b] In accordance with the cash distribution policies of the respective pipeline systems, cash distributions from Great Lakes, Northern Border, GTN and Bison are based on their respective prior quarter financial results. 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 acquisition.

(c) General Partner distributions represent the cash distributions declared to the General Partner with respect to its two percent interest plus an amount equal to incentive distributions. Incentive distributions in 2012, 2011 and 2010 were nil.

(d) 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.

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.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

Partnership cash flows increased $42 million to $222 million in 2011 compared to $180 million in 2010. This increase was primarily due to a $20 million one-time cash distribution from GTN, increased cash distributions from Great Lakes of $4 million and Northern Border of $13 million, and cash distributions from GTN and Bison of $13 million and $6 million, respectively, for the second and third quarters, partially offset by higher costs at the Partnership level of $11 million relating to the acquisitions of 25 percent membership interests in GTN and Bison, and higher financial charges.

The Partnership paid cash distributions of $155 million in 2011, an increase of $16 million compared to 2010, due to an increase in the number of common units outstanding resulting from an equity offering in May 2011 and an increase of $0.10 per common unit.

Other Cash Flows

In March and October of 2012, 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 revolving 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.

North Baja acquired the Yuma Lateral expansion facilities and existing contracts on March 5, 2010, for a purchase price of $8 million. The Yuma Lateral was placed into service on March 13, 2010. Also in 2010, the Partnership made an equity contribution of $9 million to Great Lakes of which Great Lakes used $5 million to fund debt repayments and $4 million to fund capital expenditures.

Contractual Obligations

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2012 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	312	–	–	312	–
4.65% Senior Notes due 2021	349	–	–	–	349
3.82% Series D Senior Notes due 2017	27	3	12	12	–
Interest payments on Senior Notes	140	17	50	33	40
Operating Leases	3	–	–	–	3
	831	20	62	357	392

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 $312 million was outstanding at December 31, 2012 (2011 – $363 million).

On November 20, 2012, the Partnership closed an amendment to its Senior Credit Facility, extending the maturity date to November 2017. 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 interest rate on the Senior Credit Facility averaged 1.61 percent for the year ended December 31, 2012 (2011 – 0.86 percent).

The Senior Credit Facility requires 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 coverage ratio was 2.98 to 1.00 as of December 31, 2012. The Senior Credit Facility contains 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 may become immediately due and payable. At December 31, 2012, the Partnership was in compliance with its financial covenants.

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.

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, 2012 was $714 million. As of February 28, 2013, the Partnership had $311 million outstanding under the Senior Credit Facility.

Capital Requirements

The Partnership is expected to make equity contributions totaling $9 million to Great Lakes in 2013 for scheduled debt repayments.

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 Great Lakes' Contractual Obligations

Great Lakes' contractual obligations as of December 31, 2012 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 2013 to 2018	54	9	27	18	–
9.09% series Senior Notes due 2013 to 2021	90	10	30	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	241	27	73	41	100
	595	46	130	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 $191 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2012 (2011 – $201 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2012.

The aggregate estimated fair value of Great Lakes' long-term debt was $536 million for 2012 (2011 – $541 million). The aggregate annual required repayment of senior notes is $19 million for each year 2013 through 2017. In 2012, interest expense related to Great Lakes' senior notes was $28 million (2011 – $30 million; 2010 – $31 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.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2012 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	123	–	–	123	–
Interest payments on debt	199	27	54	43	75
Operating leases	61	2	4	4	51
Other long-term obligations	2	2	–	–	–
	735	31	58	270	376

[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 of the notes do not limit the amount of unsecured debt Northern Border may incur, but do restrict secured indebtedness. At December 31, 2012, Northern Border was in compliance with all of its financial covenants.

At December 31, 2012, the aggregate estimated fair value of Northern Border's long-term debt was approximately $545 million (2011 – $541 million). In 2012, interest expense related to the senior notes was $25 million (2011 – $25 million; 2010 – $25 million).

Credit Agreement

Northern Border's credit agreement consists of a $200 million revolving credit facility. At December 31, 2012, $123 million was outstanding leaving $77 million available for future borrowings. At Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or the London Interbank Offered Rate (LIBOR) plus, in either case, an applicable margin that is based on Northern Border's long-term unsecured credit ratings. The average interest rate on Northern Border's Credit Agreement at December 31, 2012 was 1.34 percent (2011 – 1.60 percent). At December 31, 2012, 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 GTN's Contractual Obligations

GTN's contractual obligations as of December 31, 2012 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
5.09% Senior Notes due 2015	75	–	75	–	–
5.29% Senior Notes due 2020	100	–	–	–	100
5.69% Senior Notes due 2035	150	–	–	–	150
Operating leases	3	1	2	–	–
Interest payments on long-term debt	240	18	33	28	161
	568	19	110	28	411

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

GTN was in compliance with all terms and conditions of all its credit and other debt agreements at December 31, 2012.

Other

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

Summary of Bison's Contractual Obligations

Bison had commitments of $1 million as of December 31, 2012 in connection with reclamation and restoration work associated with the construction of the pipeline.

Other

Bison has a cash management agreement with TransCanada whereby Bison's funds are pooled with other TransCanada affiliates. The agreement gives Bison the ability to obtain short-term borrowings to provide liquidity for Bison's 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%
		–	

2012 Fourth Quarter Cash Distribution

On January 17, 2013, the board of directors of our General Partner declared the Partnership's fourth quarter 2012 cash distribution in the amount of $0.78 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2013 to unitholders of record as of January 29, 2013, totaled $43 million and was paid in the following manner: $42 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 2012 cash distribution represents an annual cash distribution of $3.12 per common unit.

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

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. Great Lakes, Northern Border, GTN and Bison's 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, Great Lakes, Northern Border, GTN and Bison's cash distribution policy requires the unanimous approval of their respective management committee.

Great Lakes' distribution policy is to distribute 100 percent of distributable cash flow based on earnings before income taxes, depreciation, allowance for funds used during construction (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.

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.

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

Cash From Our Pipeline Systems

Great Lakes declared its fourth quarter 2012 distribution of $14 million on January 11, 2013, of which the Partnership received its 46.45 percent share, or $6 million. The distribution was paid on February 1, 2013.

Northern Border declared and paid its fourth quarter 2012 distribution of $43 million on February 1, 2013, of which the Partnership received its 50 percent share, or $22 million.

GTN declared and paid its fourth quarter 2012 distribution of $22 million on February 1, 2013, of which the Partnership received its 25 percent share, or $6 million.

Bison declared its fourth quarter 2012 distribution of $15 million on January 11, 2013, of which the Partnership received its 25 percent share, or $4 million. The distribution was paid on February 1, 2013.

Investing Activities for our Pipeline Systems

Total capital spending for maintenance of existing facilities and growth projects were as follows:

Year Ended December 31 *(millions of dollars)*	**2012**	2011[a]	2010
Maintenance	**21**	17	7
Growth	**3**	18	14
	24	35	21

[a] 25 percent interests in each of GTN and Bison were acquired in May 2011.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011
Maintenance capital spending increased $4 million to $21 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 $15 million to $3 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.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010
Maintenance capital spending increased $10 million to $17 million in 2011 compared to $7 million in 2010. This increase was primarily due to GTN and Bison, of which we acquired 25 percent interests in 2011, and compressor engine overhauls on Northern Border's pipeline system.

Growth capital spending increased $4 million to $18 million in 2011 compared to $14 million in 2010. This increase was primarily due to the completion of the Bison pipeline and acquiring a 25 percent membership interest in Bison in 2011 and the Princeton Lateral Project on the Northern Border pipeline system.

Other Investing Activities
In 2013, our pipeline systems expect to invest approximately $57 million in maintenance capital expenditures, of which the Partnership's share would be $23 million.

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 Great Lakes, Northern Border, GTN and Bison 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 Great Lakes, Northern Border, GTN and Bison because of our ownership interests and our representation on their management committees.

We account for our investments in North Baja and Tuscarora using the consolidation method, as we wholly-own both entities.

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, 2012, Northern Border and GTN reflected regulatory assets of $28 million and $2 million, respectively, on their balance sheets (2011 – $28 million and $2 million). Northern Border and GTN also have regulatory liabilities of $16 million and $20 million, respectively, as of December 31, 2012 (2011 – $12 million and $19 million).

As of December 31, 2012 and 2011, Great Lakes, Bison, North Baja and Tuscarora did not have any regulatory assets or liabilities recorded on their respective balance sheets.

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 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 our 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 issuer, 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 issuer 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, 2012, no impairment charge has been recorded related to our equity investments in Great Lakes, Northern Border, GTN and Bison. However, if our assumptions change significantly, our requirement to record an impairment charge could change.

Due to the change in market conditions impacting Great Lakes in 2012, 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, natural gas storage market conditions, the outcome of the 2013 Section 4 general rate case, the outcome of the TransCanada Mainline regulatory hearing with the Canadian National Energy Board relating to services and tolls on that system and a general rationalization of capacity in the region and its impacts. 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 $677 million as of December 31, 2012 (2011 – $686 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 conclude that it is not 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, 2012 and 2011, we had $130 million of goodwill recorded on our balance sheet related to the North Baja and Tuscarora acquisitions. No impairment of goodwill existed at December 31, 2012.

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.

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 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 – Regulatory Environment" for additional information.

Emissions Regulation

The regulation or restriction of GHG emissions could result in changes to the consumption and demand for natural gas. This could have adverse effects on our pipeline systems, our financial position, results of operations and future prospects. The physical effects associated with GHG emissions may include changes in weather patterns, such as increases in storm intensity or temperature extremes, the availability or quality of water, or sea-level rise. These effects can impact supply and distribution chains or demand for certain products or services, or result in damage to facilities or decreased efficiency of equipment. The impact of new or proposed GHG laws and regulations is not yet certain and we cannot estimate the effect of proposed legislation on our future financial position, results of operations or cash flow. It is reasonably likely, however, that such legislation 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.

RELATED PARTY TRANSACTIONS

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. 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, Financial Statement Schedules" Note 13 "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.

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.

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. Our interest rate exposure results from our Senior Credit Facility, which is subject to variability in

LIBOR interest rates. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

Our 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 or December 31, 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.

Financial instruments are recorded at fair value on a recurring basis and are categorized into one of three categories based upon a fair value hierarchy. The Partnership has classified all of its derivative financial instruments as 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. At December 31, 2012 and 2011, there were no interest rate swaps. In 2012, the Partnership recorded interest expense of nil on the interest rate swaps and options (2011 – $14 million; 2010 – $17 million).

At December 31, 2012, we had $312 million (2011 – $363 million) outstanding on our Senior Credit Facility. If LIBOR interest rates hypothetically increased by one percent (100 basis points) compared to the rates in effect at December 31, 2012, our annual interest expense would increase and our net income would decrease by $3 million; and if LIBOR interest rates hypothetically decreased by one percent compared to the rates in effect at December 31, 2012, our annual interest expense would decrease and our net income would increase by $3 million.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its revolving credit facility. Northern Border regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. As of December 31, 2012, 74 percent of Northern Border's outstanding debt was at fixed rates (2011 – 74 percent).

If interest rates hypothetically increased by one percent (100 basis points) compared with rates in effect at December 31, 2012, Northern Border's annual interest expense would increase and its net income would decrease by approximately $1 million; and if interest rates hypothetically decreased by one percent compared with rates in effect at December 31, 2012, Northern Border's annual interest expense would decrease and its net income would increase by approximately $1 million.

Great Lakes, GTN 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 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. At December 31, 2012, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $8 million (2011 – $8 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, 2012, the Partnership had a committed revolving bank line of $500 million maturing in 2017 and the outstanding balance on this facility was $312 million. In addition, at December 31, 2012, Northern Border had a committed revolving bank line of $200 million maturing in 2016 and $123 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, 2012, 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.

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 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, 2012 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
Gregory A. Lohnes	56	Chair and Director
Steven D. Becker	62	President, Principal Executive Officer and Director
Jack F. Jenkins-Stark	62	Independent Director
Malyn K. Malquist	60	Independent Director
Walentin (Val) Mirosh	67	Independent Director
James M. Baggs	51	Director
Kristine L. Delkus	55	Director
Stuart P. Kampel	44	Vice-President and General Manager
Sandra P. Ryan-Robinson	50	Controller, Principal Financial Officer
Terry C. Ofremchuk	62	Vice-President, Taxation
Annie C. Belecki	41	Secretary
Chuck Morris	50	Treasurer
Jon A. Dobson	46	Assistant Secretary

Mr. Lohnes was appointed a director of the General Partner in January 2007 and has served as Chair of the General Partner's Board of Directors since March 2010. Mr. Lohnes' principal occupation is Executive Vice-President, Operations and Major Projects of TransCanada. Prior to November 2012, Mr. Lohnes was President, Natural Gas Pipelines of TransCanada, a position he has held since July 2010. Prior to July 2010, he was Executive Vice-President and Chief Financial Officer of TransCanada, a position he held since June 2006. Prior to June 2006, he was President and Chief Executive Officer of Great Lakes Gas Transmission Company. Mr. Lohnes has extensive senior management experience in the oil and gas industry as a result of his service as an executive officer for TransCanada and its subsidiaries. His day-to-day leadership as Executive Vice-President, Operations and Major Projects of TransCanada and his prior roles as Chief Financial Officer of the General Partner, President, Natural Gas Pipelines of TransCanada, Executive Vice-President and Chief Financial Officer of TransCanada and President and Chief Executive Officer of Great Lakes provide him with an intimate knowledge of the Partnership, including its strategies, operations, markets and financing requirements. Mr. Lohnes' business judgment, management experience and leadership skills are highly valuable in assessing our business strategies and accompanying risks.

Mr. Becker was appointed President of the General Partner in August 2010 and serves as the General Partner's principal executive officer. 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, Natural Gas Pipelines 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, Natural Gas Pipelines 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 BrightSource Energy, Inc. (designs and builds large scale solar plants that deliver solar energy in the form of steam and/or electricity), a position he has held since May 2007. 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 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 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 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 had 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 the Director of Risk Management for TransCanada and Manager, Risk Management for TransCanada for the previous five years.

Mr. Dobson was appointed Assistant Secretary of the General Partner in April 2012. Mr. Dobson's principal occupation is Associate General Counsel, Corporate and Securities Law in the U.S. Corporate Secretarial group of TransCanada, a position he has held since November 2011. He joined TransCanada in January 2011 as Senior Legal Counsel, U.S. Corporate and Securities Law and held that position until November 2011. Prior to joining TransCanada, Mr. Dobson spent 18 years in corporate legal and law firm positions, most recently from May 2008 to January 2010 as Vice-President and Assistant General Counsel of Nash Finch Company, a Minneapolis, Minnesota based wholesale food distributor and grocery retailer.

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 23, 2012.

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 or 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 2012.

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.transcanada.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 2012, 2011 and 2010 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)]	Total Compensation
Steven D. Becker	**2012**	**72,493**	**18,848**	**37,697**	**129,038**
President and Principal Executive Officer	2011	103,905	27,015	54,031	184,951
	2010	29,424	8,827	14,418	52,669
Sandra P. Ryan-Robinson[(d)]	**2012**	**62,734**	**16,311**	**32,622**	**111,667**
Controller and Principal Financial Officer	2011	21,662	5,632	11,264	38,559
	2010	–	–	–	–
Stuart P. Kampel[(e)]	**2012**	**168,101**	**43,706**	**87,412**	**299,219**
Vice-President and General Manager	2011	95,752	24,895	49,791	170,438
	2010	9,217	2,765	4,516	16,498
Terry C. Ofremchuk	**2012**	**89,632**	**23,204**	**46,609**	**159,445**
Vice-President, Taxation	2011	81,012	21,063	42,126	144,202
	2010	80,805	24,242	39,594	144,641

(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 0.26 for benefits in 2012 (2011 – factor of 0.26; 2010 – factor of 0.30).

(c) The incentive compensation reimbursement is determined monthly and calculated based on total monthly salary allocated to us multiplied by a factor of 0.52 for incentive compensation in 2012 (2011 – factor of 0.52; 2010 – factor of 0.49).

(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.

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
Gregory A. Lohnes
Malyn K. Malquist
Walentin (Val) Mirosh

Independent Director Compensation[(a)]

For the year ended December 31, 2012 *(in dollars)*	Earned or Paid in Cash[(b)]	Unit Awards[(c)]	All Other Compensation[(d)]	Total
Malyn K. Malquist	56,250	64,619	5,206	126,075
Jack F. Jenkins-Stark[(e)]	42,625	42,000	25,992	110,617
Walentin (Val) Mirosh	61,000	42,000	14,005	117,005

(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 Gregory A. Lohnes, 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 ($13,750) in DSUs. Due to this election, 318 DSUs were credited to Mr. Malquist's account in 2012, all of which were outstanding at December 31, 2012. Jack F. Jenkins-Stark elected to receive 50 percent of his Board retainer and attendance fees and committee attendance fees and 25 percent of his Lead Director and committee chair retainer fees ($30,250) in Deferred Share Units (DSUs). Due to this election, 698 DSUs were credited to Mr. Jenkins-Stark's account in 2012, all of which were outstanding at December 31, 2012. Mr. Mirosh elected to receive his fees in cash.

(c) Amounts presented reflect the compensation expense recognized related to the DSUs granted during 2012 under the DSU Plan. On January 17, 2012, each independent director was granted 899 DSUs. Mr. Malquist's unit awards included $22,619 related to 2011 Board service paid in 2012. All of the DSUs granted to Mr. Malquist, Mr. Jenkins-Stark and Mr. Mirosh were outstanding at December 31, 2012.

At December 31, 2012, Malyn K. Malquist, Jack F. Jenkins-Stark and Walentin (Val) Mirosh held 2,090, 9,845 and 5,079 DSUs, respectively. The fair value of DSUs held by Mr. Malquist, Mr. Jenkins-Stark and Mr. Mirosh at December 31, 2012 was $84,356, $397,362 and $204,999, 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 129 DSUs, Jack F. Jenkins-Stark was credited 644 DSUs and Walentin (Val) Mirosh was credited 347 DSUs. All DSUs credited during 2012 were outstanding at December 31, 2012.

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

Cash Compensation

In 2012, 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 $79,000 per annum, of which $42,000 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 $8,000 per annum. 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 25, 2012, the board approved an increase in the independent directors' 2013 annual retainer fee of $11,000 per annum, of which $7,000 will be granted in DSUs. As a result, commencing January 1, 2013, the retainer fee will be $90,000 per annum, of which $49,000 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 2012, as part of the retainer fee, each independent director received an annual grant of DSUs with a value of $42,000.

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, 2013 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	21.1	–	–
TC Pipelines GP, Inc.[(d)] 450-1st Street SW Calgary, Alberta T2P 5H1	5,797,106	10.8	–	–
Malyn K. Malquist[(e)]	4,306	*	–	–
Jack F. Jenkins-Stark[(f)]	16,081	*	–	–
Walentin (Val) Mirosh[(g)]	6,346	*	995	*
Gregory A. Lohnes[(h)]	–	–	256,890	*
Steven D. Becker[(i)]	–	–	72,859	*
Kristine L. Delkus[(j)]	–	–	97,969	*
James M. Baggs[(k)]	–	–	69,015	*
Sandra P. Ryan-Robinson[(l)]	–	–	409	*
Directors and Executive officers as a Group[(m)] (13 people)	26,733	*	517,086	*

(a) A total of 53,472,766 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) Includes 3,306 DSUs and 1,000 common units.

(f) Includes 11,193 DSUs and 4,888 common units held by the Jenkins-Stark Family Trust dated June 16, 1995.

(g) Includes 6,346 DSUs.

(h) Includes 235,938 options exercisable within 60 days for TransCanada common shares, 10,790 TransCanada common shares held directly, 4,672 TransCanada common shares held in his Employee Savings Plan account and 5,490 TransCanada common shares owned by his spouse, of which he disclaims beneficial ownership.

(i) Includes 49,991 options exercisable within 60 days for TransCanada common shares, 18,030 TransCanada common shares held directly and 4,838 TransCanada common shares held in his Employee Savings Plan account.

(j) Includes 83,421 options exercisable within 60 days for TransCanada common shares, 7,849 TransCanada common shares held directly and 6,699 TransCanada common shares held in her Employee Savings Plan account.

(k) Includes 63,287 options exercisable within 60 days for TransCanada common shares, 2,761 TransCanada common shares held in a RRSP account, 2,263 TransCanada common shares held in his Employee Savings Plan account and 704 TransCanada common shares held in his spouse's Employee Savings Plan account.

(l) Includes 409 TransCanada common shares held in her Employee Savings Plan account.

(m) Includes 432,637 options exercisable within 60 days for TransCanada common shares, 20,845 DSUs, 16,539 common shares of TransCanada owned by immediate family members of which beneficial ownership of 5,600 common shares is disclaimed and 35,898 common shares held in the TransCanada Employee Savings Plan.

* Less than one percent.

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

At February 28, 2013, TransCanada owns 11,287,725 common units and the Partnership's General Partner owns 5,797,106 common units, representing an aggregate 31.3 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 33.3 percent by virtue of its indirect ownership of the General Partner and 31.3 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, 2012 (2011 – $2 million; 2010 – $2 million).

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

Great Lakes, GTN and Bison have cash management agreements with TransCanada whereby their funds are pooled with other TransCanada affiliates. The agreements also give these pipeline systems the ability to obtain short-term borrowings to provide liquidity for their 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 $77 million of transportation revenues under these contracts in 2012 (2011 – $81 million; 2010 – $149 million). This amount represents 42 percent of total revenues earned by Great Lakes in 2012 (2011 – 32 percent; 2010 – 57 percent). Great Lakes also earned $1 million in affiliated rental revenue in 2012, 2011 and 2010.

Revenue from TransCanada and its affiliates of $36 million is included in the Partnership's equity earnings from Great Lakes in 2012 (2011 – $38 million; 2010 – $69 million). At December 31, 2012, $10 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2011 – $7 million).

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, 2012, 2011 and 2010 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2012 and 2011 are summarized in the following tables:

Year ended December 31 *(millions of dollars)*	**2012**	2011	2010
Capital and operating costs charged by TransCanada's subsidiaries to:			
Great Lakes[a]	**33**	31	30
Northern Border[a]	**31**	29	26
GTN[a][b]	**29**	22	–
Bison[a][b]	**6**	8	–
North Baja	**4**	4	4
Tuscarora	**4**	5	4
Impact on the Partnership's net income:			
Great Lakes	**15**	14	13
Northern Border	**14**	13	13
GTN[b]	**7**	5	–
Bison[b]	**1**	1	–
North Baja	**4**	4	3
Tuscarora	**4**	5	4

December 31 *(millions of dollars)*	**2012**	2011
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
Great Lakes[a]	**4**	3
Northern Border[a]	**4**	3
GTN[a]	**3**	3
Bison[a]	**1**	1
North Baja	**1**	1
Tuscarora	**1**	1

[a] Represents 100 percent of the costs.

[b] 25 percent interests in each of GTN and Bison were acquired in May 2011.

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)*	**2012**	2011
Audit Fees[(a)]	**408**	350
Audit Related Fees	**–**	–
Tax Fees[(b)]	**–**	–
All Other Fees	**–**	–
Total	**408**	350

[(a)] $75 thousand of the 2011 Audit Fees relate to comfort letters and consents issued in conjunction with the financing related to the GTN and Bison Acquisitions in May 2011, and the $350 million Senior Notes issued in July 2011.

[(b)] The Partnership has not engaged its external auditors for any tax or other services in 2012 or 2011.

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, 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).

No.	Description
*2.3	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)
*2.4	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).
*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).
*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).

No.	Description
*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).
*10.7	Yuma Transfer Agreement by and between Gas Transmission Northwest Corporation and North Baja Pipeline, LLC dated March 5, 2010 (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 30, 2010).
*10.8	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).
*10.10	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).

No.	Description
*10.11	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)).
*10.12	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).
*#10.13	TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), effective as of October 18, 2007, as amended on December 10, 2008 (Incorporated by reference to Exhibit 10.25 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.14	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).
*10.15	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).
*10.16	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).
*10.17	Guaranty by TransCanada Pipeline USA Ltd. dated as of April 26, 2011 with respect to the obligations of TransCanada American Investments Ltd. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on April 27, 2011).
*10.18	Guaranty by TransCanada Pipeline USA Ltd. dated as of April 26, 2011 with respect to the obligations of TC Continental Pipeline Holdings Inc. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on April 27, 2011).
*10.19	364-Day Senior Bridge Loan Agreement, dated as of May 3, 2011, among TC PipeLines, LP, the lenders from time to time party thereto, and SunTrust Bank, as Administrative Agent (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on May 5, 2011).
*10.20	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).
10.21	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.
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.

No.	Description
23.2	Consent of KPMG LLP with respect to the financial statements of Great Lakes Gas Transmission Limited Partnership.
23.3	Consent of KPMG LLP with respect to the financial statements of Northern Border Pipeline Company.
23.4	Consent of KPMG LLP with respect to the financial statements of TC PipeLines, LP for the year ended December 31, 2010.
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 FT5840 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 1, 2005. (Incorporated by reference to Exhibit 10.6 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007).
*99.2	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).
*99.3	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).
*99.4	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).
*99.5	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).
*99.6	Transportation Service Agreement FT4760 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Incorporated by reference to Exhibit 99.11 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.7	Transportation Service Agreement FT4761 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Incorporated by reference to Exhibit 99.12 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.8	Transportation Service Agreement FT14131 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Incorporated by reference to Exhibit 99.13 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.9	Transportation Service Agreement FT14132 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Incorporated by reference to Exhibit 99.14 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.10	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).

No.	Description
*99.11	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).
*99.12	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).
*99.13	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).
*99.14	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).
*99.15	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).
99.16	Transportation Service Agreement FT17593 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated October 30, 2012.
99.17	Transportation Service Agreement FT17196 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated December 3, 2012.
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 2013.

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/ Gregory A. Lohnes Gregory A. Lohnes	Chair	February 28, 2013
/s/ Steven D. Becker Steven D. Becker	President and Principal Executive Officer	February 28, 2013
/s/ Sandra P. Ryan-Robinson Sandra P. Ryan-Robinson	Controller and Principal Financial Officer	February 28, 2013
/s/ James M. Baggs James M. Baggs	Director	February 28, 2013
/s/ Kristine L. Delkus Kristine L. Delkus	Director	February 28, 2013
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 28, 2013
/s/ Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	February 28, 2013
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 28, 2013

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, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners' equity for the years then ended. We also have audited TC PipeLines, LP internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control – Integrated Framework* 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 the Partnership's 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 entity'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, 2012 and 2011, and the results of their operations and their cash flows for the years then ended, 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, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Houston, Texas
February 28, 2013

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 statements of income, comprehensive income, cash flows and changes in partners' equity of TC PipeLines, LP for the year ended December 31, 2010. These consolidated financial statements are the responsibility of management of the General Partner of TC PipeLines, LP. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated results of TC PipeLines, LP's operations and its consolidated cash flows for the year ended December 31, 2010, in conformity with U.S generally accepted accounting principles.

/s/ KPMG LLP

Chartered Accountants
Calgary, Canada
February 24, 2011

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2012**	2011
Assets		
Current Assets		
Cash and cash equivalents	**3**	29
Accounts receivable and other (Note 16)	**9**	9
	12	38
Investments in unconsolidated affiliates (Note 4)	**1,563**	1,610
Plant, property and equipment (Note 5)	**288**	298
Goodwill	**130**	130
Other assets	**5**	6
	1,998	2,082
Liabilities and Partners' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**7**	5
Accrued interest	**1**	1
Current portion of long-term debt (Note 7)	**3**	3
	11	9
Long-term debt (Note 7)	**685**	739
Other liabilities	**1**	1
	697	749
Partners' Equity (Note 8)		
Common units	**1,275**	1,307
General partner	**27**	27
Accumulated other comprehensive loss	**(1)**	(1)
	1,301	1,333
	1,998	2,082

Subsequent events (Note 18)

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)	**2012**	2011	2010
Equity earnings from unconsolidated affiliates[(a)] (Note 4)	**129**	154	126
Transmission revenues	**65**	70	69
Operating expenses	**(17)**	(15)	(13)
General and administrative	**(6)**	(9)	(4)
Depreciation	**(11)**	(15)	(15)
Financial charges and other (Note 9)	**(23)**	(28)	(26)
Net income	**137**	157	137
Net income allocation (Note 10)			
Common units	**134**	154	134
General Partner	**3**	3	3
	137	157	137
Net income per common unit (Note 10) – basic and diluted	**$2.51**	$3.02	$2.91
Weighted average common units outstanding *(millions)* – basic and diluted	**53.5**	51.1	46.2
Common units outstanding, end of year *(millions)*	**53.5**	53.5	46.2

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2012**	2011	2010
Net income[(a)]	**137**	157	137
Other comprehensive income			
Change associated with current period hedging transactions (Note 15)	**–**	14	10
Change associated with current period hedging transaction of investees	**–**	–	1
	–	14	11
Total comprehensive income	**137**	171	148

(a) 25 percent interests in each of GTN and Bison were acquired May 2011.

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)	**2012**	2011	2010
Cash Generated From Operations			
Net income	**137**	157	137
Depreciation	**11**	15	15
Amortization of debt issue costs (Note 9)	**1**	2	–
Equity earnings in excess of cumulative distributions:			
Bison[(a)]	**–**	(1)	–
Decrease/(increase) in other long-term liabilities	**1**	(1)	1
Decrease/(increase) in operating working capital (Note 12)	**3**	(3)	3
	153	169	156
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Great Lakes	**17**	13	10
Northern Border	**24**	24	19
GTN[(a)]	**9**	21	–
Bison[(a)]	**5**	–	–
Investment in Great Lakes (Note 4)	**(9)**	(9)	(9)
Investment in Northern Border (Note 4)	**–**	(55)	–
Acquisition of GTN and Bison (Note 6)	**–**	(539)	–
Capital expenditures	**(2)**	(3)	(9)
	44	(548)	11
Financing Activities			
Distributions paid (Note 11)	**(169)**	(155)	(139)
Equity issuance, net	**–**	338	–
Long term debt issued (Note 7)	**8**	894	74
Long-term debt repaid (Note 7)	**(62)**	(666)	(101)
Debt issue costs	**–**	(7)	–
	(223)	404	(166)
(Decrease)/increase in cash and cash equivalents	**(26)**	25	1
Cash and cash equivalents, beginning of year	**29**	4	3
Cash and cash equivalents, end of year	**3**	29	4
Interest payments made	**24**	13	9

(a) 25 percent interests in each of GTN and Bison were acquired in May 2011.

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

	Common Units		General Partner	Accumulated Other Comprehensive Loss	Partners' Equity	
	(millions of units)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of units)	(millions of dollars)
Partners' equity at December 31, 2009	46.2	1,107	23	(26)	46.2	1,104
Net income	–	134	3	–	–	137
Distributions paid	–	(136)	(3)	–	–	(139)
Other comprehensive income	–	–	–	11	–	11
Partners' equity at December 31, 2010	46.2	1,105	23	(15)	46.2	1,113
Net Income[(a)]	–	154	3	–	–	157
Equity issuance, net (Note 6 and 8)	7.3	331	7	–	7.3	338
Distributions paid	–	(152)	(3)	–	–	(155)
Excess purchase price over net acquired assets (Note 6)	–	(131)	(3)	–	–	(134)
Other comprehensive income	–	–	–	14	–	14
Partners' equity at December 31, 2011	53.5	1,307	27	(1)	53.5	1,333
Net Income	**–**	**134**	**3**	**–**	**–**	**137**
Distributions paid	**–**	**(166)**	**(3)**	**–**	**–**	**(169)**
Partners' equity at December 31, 2012	**53.5**	**1,275**	**27**	**(1)**	**53.5**	**1,301**

(a) 25 percent interests in each of GTN and Bison were acquired in May 2011.

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:

- a 46.45 percent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes), a Delaware limited partnership. Great Lakes owns a 2,115-mile pipeline that transports natural gas serving markets in Minnesota, Wisconsin, Michigan and Eastern Canada;
- a 50 percent general partner interest in Northern Border Pipeline Company (Northern Border), a Texas general partnership. Northern Border owns a 1,408-mile pipeline that transports natural gas from the Montana-Saskatchewan border to markets in the Midwestern U.S.;
- a 25 percent interest in Gas Transmission Northwest LLC (GTN), a Delaware limited liability company. GTN owns a 1,353-mile pipeline that transports natural gas from the British Columbia, Canada/Idaho border to a point at the Oregon/California border;
- a 25 percent interest in Bison Pipeline LLC (Bison), a Delaware limited liability company. Bison owns a 303-mile pipeline that transports natural gas from the Powder River Basin in Wyoming to Northern Border's pipeline system in North Dakota;
- a 100 percent interest in North Baja Pipeline, LLC (North Baja), a Delaware limited liability company. North Baja owns an 86-mile pipeline that transports natural gas between an interconnection with El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection near Ogilby, California on the California/Mexico border with the Gasoducto Rosarito natural gas pipeline system; and
- a 100 percent interest in Tuscarora Gas Transmission Company (Tuscarora), a Nevada general partnership. Tuscarora owns a 305-mile pipeline that transports natural gas from Oregon, where it interconnects with facilities of GTN, to a terminus in Northern Nevada.

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 12.6 percent interest in the Partnership at December 31, 2012. TransCanada also indirectly holds an additional 11,287,725 common units representing a 20.7 percent limited partner interest in the Partnership for a total interest in the Partnership of 33.3 percent at December 31, 2012.

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, 2012 and 2011 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2012, 2011 and 2010.

(a) Basis of Presentation
The Partnership uses the equity method of accounting for its investments in Great Lakes, Northern Border, GTN and Bison, over which it is able to exercise significant influence. The Partnership consolidates its investments in North Baja and Tuscarora.

(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 short-term investments with original maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

(d) Plant, Property and Equipment

Plant, property and equipment of North Baja and Tuscarora 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. Depreciation of pipeline facilities and compression equipment is provided on a straight-line composite basis over the estimated useful life of the pipeline and compression equipment of 20 to 30 years. Metering and other is depreciated on a straight-line basis over the estimated useful lives of the equipment, which range from 5 to 30 years. 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.

(e) 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 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 our 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 issuer, 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 issuer 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.

(f) Impairment of Long-lived Assets

Long-lived assets, such as property, plant, and equipment, which are 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.

(g) Partners' Equity

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

(h) Revenue Recognition

Transmission revenues relate to North Baja and Tuscarora operations and 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, 2012, 2011 and 2010, the Partnership has not recognized any transmission revenue that is subject to possible refund.

(i) 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.

(j) 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 concludes that it is not 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.

(k) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable and certain accrued expenses the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments 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.

(l) 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.

(m) Asset Retirement Obligation

The Partnership recognizes and measures liabilities associated with the retirement of tangible long-lived assets at fair value as incurred and capitalizes them as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time is classified as an operating expense. Retirement obligations associated with relevant long-lived assets are those for which a legal obligation exists under enacted laws, statutes, ordinances, or written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

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. Asset retirement obligations exist for certain of our transmission assets; however, the fair value of the obligations cannot be determined due to the inability to determine the scope of asset retirements, as well as the end of the transmission system life is not determinable with the degree of accuracy necessary to currently establish a liability for the obligation.

We are required to operate and maintain our natural gas pipeline systems, 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, 2012 and 2011. We continue to evaluate our asset retirement obligations and future developments that could impact amounts recorded.

(n) Government Regulation

North Baja and Tuscarora, the Partnership's wholly-owned pipeline systems, 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 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. Tuscarora and North Baja had no regulatory assets or liabilities as of December 31, 2012 and 2011. Allowance for funds used during construction is capitalized and included in plant, property and equipment.

(o) 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 ACCOUNTING PRONOUNCEMENTS

The Financial Accounting Standards Board issued an update to Accounting Standards Codification (ASC) 350 – Intangibles – Goodwill and Other. Adoption of this update has resulted in a change in the accounting policy related to testing goodwill for impairment, as the Partnership is now permitted under U.S. GAAP to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount as a basis for determining whether it is required to proceed to the two-step quantitative impairment test. The Partnership adopted this update effective January 1, 2012. The adoption of this update is not expected to have a material impact on our annual goodwill assessment.

NOTE 4 INVESTMENTS IN UNCONSOLIDATED AFFILIATES

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

(unaudited) *(millions of dollars)*	**Ownership Interest at December 31, 2012**	Equity Earnings from Unconsolidated Affiliates			Investment in Unconsolidated Affiliates	
		Year ended December 31			December 31	
		2012	2011	2010	**2012**	2011
Great Lakes	46.45%	**27**	60	59	**677**	686
Northern Border[(a)]	50%	**72**	75	67	**512**	536
GTN[(b)]	25%	**19**	12	–	**216**	225
Bison[(b)]	25%	**11**	7	–	**158**	163
		129	154	126	**1,563**	1,610

(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.

(b) 25 percent interests in each of GTN and Bison were acquired in May 2011.

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.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2012, 2011, and 2010.

At December 31, 2012 the partnership had a $458 million (2011 – $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 quarter and fourth quarter of 2012, 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)	**2012**	2011
Assets		
Current assets	**56**	65
Plant, property and equipment, net	**799**	826
Other assets	**–**	1
	855	892
Liabilities and Partners' Equity		
Current liabilities	**30**	30
Long-term debt, including current maturities	**354**	373
Partners' equity	**471**	489
	855	892

Year ended December 31 (millions of dollars)	**2012**	2011	2010
Transmission revenues	**182**	250	262
Operating expenses	**(66)**	(62)	(59)
Depreciation	**(31)**	(32)	(40)
Financial charges and other	**(28)**	(30)	(31)
Michigan business tax	**–**	2	(5)
Net income	**57**	128	127

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 – On September 27, 2012, Northern Border filed a petition with FERC requesting approval of the Northern Border Settlement with its customers to modify its transportation rates. In January 2013, FERC gave final approval for the settlement which establishes maximum long-term transportation rates and charges on the Northern Border system effective January 1, 2013. 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, 2012, 2011 and 2010.

At December 31, 2012, the Partnership had a $119 million (2011 – $120 million) difference between the carrying value of Northern Border and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in the Partnership's investment in Northern Border relating to the Partnership's April 2006 acquisition of an additional 20 percent general partnership interest in Northern Border.

The summarized financial information for Northern Border is as follows:

December 31 (millions of dollars)	**2012**	2011
Assets		
Cash and cash equivalents	**28**	33
Other current assets	**35**	35
Plant, property and equipment, net	**1,234**	1,267
Other assets	**31**	31
	1,328	1,366
Liabilities and Partners' Equity		
Current liabilities	**53**	48
Deferred credits and other	**16**	13
Long-term debt, including current maturities	**473**	473
Partners' equity		
Partners' capital	**789**	835
Accumulated other comprehensive loss	**(3)**	(3)
	1,328	1,366

Year ended December 31 (millions of dollars)	**2012**	2011	2010
Transmission revenues	**311**	310	295
Operating expenses	**(79)**	(73)	(74)
Depreciation	**(63)**	(62)	(62)
Financial charges and other	**(24)**	(22)	(23)
Net income	**145**	153	136

GTN

On May 3, 2011, the Partnership acquired a 25 percent membership interest in GTN from a subsidiary of TransCanada. The acquisition was accounted for as a transaction between entities under common control, whereby the equity investment in GTN was recorded at TransCanada's carrying value. See Note 6 for additional disclosure regarding the Acquisitions.

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

In November 2011, FERC approved a Stipulation and Agreement of Settlement with shippers and regulators regarding GTN's rates and terms and conditions of service (GTN Settlement) without modification, effective January 1, 2012. The GTN Settlement includes a moratorium on the filing of future rate proceedings until December 31, 2015. Following the expiration of the moratorium, GTN must file a rate case such that the new rates will be effective January 1, 2016.

The Partnership recorded no undistributed earnings from GTN for the year ended December 31, 2012 and 2011.

The summarized financial information for GTN is as follows:

December 31 (millions of dollars)	**2012**	2011
Assets		
Current assets	**50**	55
Plant, property and equipment, net	**1,174**	1,207
Other assets	**1**	1
	1,225	1,263
Liabilities and Members' Equity		
Current liabilities	**16**	18
Deferred credits and other	**20**	20
Long-term debt, including current maturities	**325**	325
Members' capital	**864**	900
	1,225	1,263

Year ended December 31 (millions of dollars)	**2012**	2011[a]
Transmission revenues	**198**	133
Operating expenses	**(48)**	(37)
Depreciation	**(54)**	(36)
Financial charges and other	**(18)**	(15)
Net income	**78**	45

[a] 25 percent interest in GTN was acquired in May 2011.

Bison

On May 3, 2011, the Partnership acquired a 25 percent membership interest in Bison from a subsidiary of TransCanada. The acquisition was accounted for as a transaction between entities under common control, whereby the equity investment in Bison was recorded at TransCanada's carrying value. See Note 6 for additional disclosure regarding the Acquisitions.

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

The Partnership recorded no undistributed earnings from Bison for the year ended December 31, 2012 (2011 – $1 million).

The summarized financial information for Bison is as follows:

December 31 (millions of dollars)	**2012**	2011
Assets		
Current assets	**7**	10
Plant, property and equipment, net	**649**	658
	656	668
Liabilities and Members' Equity		
Current liabilities	**25**	17
Members' capital	**631**	651
	656	668

Year ended December 31 (millions of dollars)	**2012**	2011[a]
Transmission revenues	**80**	52
Operating expenses	**(16)**	(11)
Depreciation	**(19)**	(13)
Net income	**45**	28

[a] 25 percent interest in Bison was acquired in May 2011.

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

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

	2012			2011		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**292**	**(117)**	**175**	290	(110)	180
Compression	**103**	**(22)**	**81**	105	(20)	85
Metering and other	**43**	**(11)**	**32**	42	(9)	33
	438	**(150)**	**288**	437	(139)	298

NOTE 6 ACQUISITIONS

GTN and Bison Equity Investment Acquisitions

On May 3, 2011, the Partnership acquired 25 percent membership interests in GTN and Bison from 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. GTN and Bison are both Delaware limited liability companies regulated by FERC, and they are operated by subsidiaries of TransCanada.

The total purchase price of the Acquisitions was $605 million (the Purchase Price). 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 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 Acquisitions were accounted for as transactions 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.

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)	**2012**	2011
Senior Credit Facility due 2017	**312**	363
4.65% Senior Notes due 2021	**349**	349
6.89% Series C Senior Notes due 2012	**–**	3
3.82% Series D Senior Notes due 2017	**27**	27
	688	742
Less: current portion of long-term debt	**3**	3
	685	739

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 $312 million was outstanding at December 31, 2012 (2011 – $363 million), leaving $188 million available for future borrowing.

On July 13, 2011, the Partnership closed an amendment to its Senior Credit Facility increasing the senior revolving credit facility from $250 million to $500 million, and extending the maturity date of the senior revolving credit facility to July 2016 from December 2011. On November 20, 2012, the Senior Credit Facility was further amended, extending the maturity date to November 2017. 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 1.61 percent for the year ended December 31, 2012. The interest rate was 1.47 percent at December 31, 2012.

The LIBOR-based interest rate on the Senior Credit Facility averaged 0.86 percent for the year ended December 31, 2011. After hedging activity, the LIBOR-based interest rate incurred on the Senior Credit Facility averaged 4.07 percent for the year ended December 31, 2011. Prior to the hedging activities, the LIBOR-based interest rate was 1.65 percent at December 31, 2011. As of December 31, 2012 there were no interest rate hedges in place.

On June 17, 2011, the Partnership closed a $350 million public debt offering of 10-year, senior unsecured notes with an interest rate of 4.65 percent. Proceeds were used to repay funds borrowed under the Partnership's bridge loan facility and to partially repay borrowings under our existing Senior Credit Facility. The senior notes mature June 15, 2021.

On May 3, 2011, the Partnership entered into an agreement with SunTrust Robinson Humphrey, Inc., as Arranger, for a 364-day senior unsecured bridge loan facility for up to $400 million to fund the GTN and Bison Acquisitions. Borrowings under the bridge loan facility bore interest based, at the Partnership's election, on the lenders' base rate or the LIBOR plus in either case, an applicable margin. On May 3, 2011, the Partnership drew $61 million to partially fund the GTN and Bison Acquisitions. Please see Note 6 for more details on the Acquisitions. On June 17, 2011, the Partnership repaid the $61 million draw, and the bridge loan facility was cancelled. The interest rate on the loan made under the bridge loan facility was 1.7 percent.

At December 31, 2012, 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.

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.

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

(millions of dollars)	
2013	3
2014	4
2015	4
2016	4
2017	324
Thereafter	349
	688

NOTE 8 PARTNERS' EQUITY

At December 31, 2012 and 2011, Partners' equity included 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 12.6 percent ownership in the Partnership at December 31, 2012 and 2011.

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 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 Acquisitions.

NOTE 9 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars, except per unit)	**2012**	2011	2010
Interest expense on long-term debt	**22**	14	9
Loss on interest rate swaps and options	**–**	14	17
Interest income	**–**	(2)	–
Amortization of debt issue costs	**1**	2	–
	23	28	26

NOTE 10 NET INCOME PER COMMON UNIT

Net income per common unit is computed by dividing net income, after deduction of the General Partner's allocation, 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 unit)	**2012**	2011	2010
Net income[(a)]	**137**	157	137
Net income allocated to General Partner	**(3)**	(3)	(3)
Net income allocable to common units	**134**	154	134
Weighted average common units outstanding *(millions)* – basic and diluted	**53.5**	51.1	46.2
Net income per common unit – basic and diluted	**$2.51**	$3.02	$2.91

[(a)] 25 percent interests in each of GTN and Bison were acquired May 2011.

NOTE 11 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 $0.78 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 are 15 percent and 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, 2012, the Partnership distributed $3.10 per common unit (2011 – $3.04 per common unit; 2010 – $2.94 per common unit) for a total of $169 million (2011 – $155 million; 2010 – $139 million). The distributions paid for the year ended December 31, 2012, 2011 and 2010 included no incentive distributions to the General Partner. Partnership income 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 12 CHANGE IN WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2012**	2011	2010
Decrease in accounts receivable and other	**1**	–	–
Increase/(decrease) in accounts payable and accrued liabilities	**2**	(3)	3
Decrease/(increase) in operating working capital	**3**	(3)	3

NOTE 13 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, 2012 (2011 – $2 million; 2010 – $2 million).

As operator, TransCanada's subsidiaries provide capital and operating services to Great Lakes, Northern Border, GTN, Bison, 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, 2012, 2011 and 2010 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2012 and 2011 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2012**	2011	2010
Capital and operating costs charged by TransCanada's subsidiaries to:			
Great Lakes[(a)]	**33**	31	30
Northern Border[(a)]	**31**	29	26
GTN[(a)(b)]	**29**	22	–
Bison[(a)(b)]	**6**	8	–
North Baja	**4**	4	4
Tuscarora	**4**	5	4
Impact on the Partnership's net income:			
Great Lakes	**15**	14	13
Northern Border	**14**	13	13
GTN[(b)]	**7**	5	–
Bison[(b)]	**1**	1	–
North Baja	**4**	4	3
Tuscarora	**4**	5	4

December 31 (millions of dollars)	**2012**	2011
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
Great Lakes[(a)]	**4**	3
Northern Border[(a)]	**4**	3
GTN[(a)]	**3**	3
Bison[(a)]	**1**	1
North Baja	**1**	1
Tuscarora	**1**	1

(a) Represents 100 percent of the costs.

(b) 25 percent interests in each of GTN and Bison were acquired in May 2011.

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 $77 million of transportation revenues under these contracts in 2012 (2011 – $81 million; 2010 – $149 million). This amount represents 42 percent of total revenues earned by Great Lakes in 2012 (2011 – 32 percent; 2010 – 57 percent). Great Lakes also earned $1 million in affiliated rental revenue in 2012 (2011 – $1 million; 2010 – $1 million).

Revenue from TransCanada and its affiliates of $36 million is included in the Partnership's equity earnings from Great Lakes in 2012 (2011 – $38 million; 2010 – $69 million). At December 31, 2012, $10 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2011 – $7 million).

NOTE 14 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2012 and 2011:

Quarter ended (millions of dollars except per common unit amounts)	**Mar 31**	**Jun 30**	**Sep 30**	**Dec 31**
2012				
Equity earnings	**38**	**31**	**31**	**29**
Transmission revenues	**16**	**16**	**17**	**16**
Net income	**39**	**33**	**35**	**30**
Net income per common unit	**$0.71**	**$0.60**	**$0.64**	**$0.56**
Cash distribution paid	**42**	**42**	**43**	**43**
2011				
Equity earnings[a]	39	37	40	38
Transmission revenues	17	18	18	17
Net income[a]	42	36	41	38
Net income per common unit	$0.90	$0.69	$0.75	$0.70
Cash distributions paid	35	35	42	42

[a] 25 percent interests in each of GTN and Bison were acquired May 2011.

NOTE 15 FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

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

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

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

(b) Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable and other, accounts payable and accrued liabilities, and accrued interest approximate their fair values because of the short maturity or duration of these instruments, or because the instruments bear a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership's long-term debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates.

The estimated fair values of the Partnership's and its subsidiary's long-term debt as of December 31, 2012 and 2011 are as follows:

	2012		2011	
December 31 (millions of dollars)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Senior Credit Facility due 2017	**312**	**312**	363	363
4.65% Senior Notes due 2021	**349**	**372**	349	368
6.89% Series C Senior Notes due 2012	**–**	**–**	3	3
3.82% Series D Senior Notes due 2017	**27**	**30**	27	29
	688	**714**	742	763

The Partnership's Senior Credit Facility results in exposures to changing interest rates. Until December 12, 2011, the Partnership used derivatives to assist in managing its exposure to interest rate risk.

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.

Financial instruments are recorded at fair value on a recurring basis and are categorized into one of three categories based upon a fair value hierarchy. The Partnership has classified all of its derivative financial instruments as 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. At December 31, 2012 and 2011, the fair value of the interest rate swaps accounted for as hedges was nil. In 2012, the Partnership recorded interest expense of nil on the interest rate swaps and options (2011 – $14 million; 2010 – $17 million).

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. Our interest rate exposure results from our Senior Credit Facility, which is subject to variability in LIBOR interest rates. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate 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. At December 31, 2012, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $8 million (2011 – $8 million).

NOTE 16 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2012**	2011
Accounts receivable	**8**	8
Inventory	**1**	1
	9	9

NOTE 17 REGULATORY MATTERS

Tuscarora – On March 9, 2012, Tuscarora received approval from FERC for a Stipulation and Agreement of Settlement (Tuscarora Settlement). The Tuscarora Settlement includes three-year contract extensions to the term of a number of contracts with Tuscarora's largest customer, provides rates effective January 1, 2012, and a moratorium on the filing of future rates proceedings under NGA Section 4 or 5 until December 31, 2014. Pursuant to the Tuscarora Settlement, Tuscarora will have no future obligation to file a Section 4 rate case.

NOTE 18 SUBSEQUENT EVENTS

On January 17, 2013, the board of directors of our General Partner declared the Partnership's fourth quarter 2012 cash distribution in the amount of $0.78 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2013 to unitholders of record as of January 29, 2013, totaled $43 million and was paid in the following manner: $42 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.

Great Lakes declared its fourth quarter 2012 distribution of $14 million on January 11, 2013, of which the Partnership received its 46.45 percent share or $6 million. The distribution was paid on February 1, 2013.

Northern Border declared its fourth quarter 2012 distribution of $43 million on February 1, 2013, of which the Partnership received its 50 percent share or $22 million. The distribution was paid on February 1, 2013.

GTN declared its fourth quarter 2012 distribution of $22 million on January 11, 2013, of which the Partnership received its 25 percent share or $6 million. The distribution was paid on February 1, 2013.

Bison declared its fourth quarter 2012 distribution of $15 million on January 11, 2013, of which the Partnership received its 25 percent share or $4 million. The distribution was paid on February 1, 2013.

In January 2013, FERC gave final approval for the Northern Border Settlement to become effective January 1, 2013.

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, 2012 and 2011, 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, 2012, 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, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012, in accordance with U.S. generally accepted accounting principles.

Houston, Texas
February 13, 2013

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
BALANCE SHEETS

December 31, 2012 and 2011 (In thousands)	**2012**	2011
Assets		
Current assets:		
Cash and cash equivalents	**$ 31**	47
Demand loan receivable from affiliate	**26,474**	36,813
Accounts receivable:		
Trade	**5,991**	8,610
Affiliates	**10,563**	7,064
Materials and supplies	**10,771**	10,626
Other	**2,123**	2,107
Total current assets	**55,953**	65,267
Property, plant, and equipment:		
Property, plant, and equipment	**2,069,305**	2,069,228
Construction work in progress	**1,292**	3,640
	2,070,597	2,072,868
Less accumulated depreciation and amortization	**(1,271,707)**	(1,246,620)
Total property, plant, and equipment, net	**798,890**	826,248
Other assets	**507**	553
Total assets	**$ 855,350**	892,068
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable:		
Trade	**$ 2,161**	7,651
Affiliates	**5,009**	3,131
Current maturities of long-term debt	**19,000**	19,000
Partnership income taxes payable	**–**	3,238
Taxes payable (other than income)	**13,342**	7,805
Accrued interest	**7,738**	8,076
Other	**2,318**	–
Total current liabilities	**49,568**	48,901
Long-term debt, net of current maturities	**335,000**	354,000
Other liabilities	**296**	436
Partners' capital	**470,486**	488,731
Total liabilities and partners' capital	**$ 855,350**	892,068

See accompanying notes to financial statements.

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

Years ended December 31, 2012, 2011, and 2010 *(In thousands)*	**2012**	2011	2010
Operating revenues	**$ 182,423**	250,006	262,391
Operating expenses:			
Operation and maintenance	**47,671**	44,371	41,558
Depreciation and amortization	**30,981**	32,217	40,488
Taxes, other than income	**18,798**	17,476	17,694
Total operating expenses	**97,450**	94,064	99,740
Operating income	**84,973**	155,942	162,651
Other income, net	**479**	–	238
Interest and debt expense	**(28,412)**	(29,929)	(31,339)
Affiliated interest income	**29**	40	205
Income before partnership income taxes	**57,069**	126,053	131,755
Partnership income tax (expense) benefit	**186**	1,915	(5,290)
Net income	**$ 57,255**	127,968	126,465
Partners' capital:			
Balance at beginning of year	**$ 488,731**	498,663	501,298
Net income	**57,255**	127,968	126,465
Distributions to partners	**(94,500)**	(156,900)	(149,100)
Contributions from partners	**19,000**	19,000	20,000
Balance at end of year	**$ 470,486**	488,731	498,663

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF CASH FLOWS

Years ended December 31, 2012, 2011, and 2010 (In thousands)	**2012**	2011	2010
Cash flows from operating activities:			
Net income	**$ 57,255**	127,968	126,465
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**30,981**	32,217	40,488
Deferred partnership income taxes	**–**	(5,153)	1,816
Allowance for funds used during construction, equity	**(67)**	(84)	(187)
Gain on sale of assets, net	**(380)**	–	–
Asset and liability changes:			
Accounts receivable	**(880)**	10,222	10,006
Other current assets	**(161)**	81	(442)
Noncurrent assets	**46**	69	97
Accounts payable	**(3,612)**	(3,854)	(3,393)
Partnership income taxes payable	**(3,238)**	(491)	(248)
Other current liabilities	**7,517**	(735)	(1,665)
Noncurrent liabilities	**(140)**	–	–
Net cash provided by operating activities	**87,321**	160,240	172,937
Cash flows from investing activities:			
Additions to property, plant, and equipment	**(3,176)**	(11,444)	(13,972)
Net change in demand loan receivable from affiliate	**10,339**	8,111	(10,950)
Net cash provided by (used in) investing activities	**7,163**	(3,333)	(24,922)
Cash flows from financing activities:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(19,000)
Distributions to partners	**(94,500)**	(156,900)	(149,100)
Contributions from partners	**19,000**	19,000	20,000
Net cash used in financing activities	**(94,500)**	(156,900)	(148,100)
Net change in cash and cash equivalents	**(16)**	7	(85)
Cash and cash equivalents at beginning of year	**47**	40	125
Cash and cash equivalents at end of year	**$31**	47	40
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$28,704**	30,177	31,582
Partnership income taxes paid	**2,153**	2,417	2,873

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO FINANCIAL STATEMENTS
December 31, 2012 and 2011

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, 2012 and 2011 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 owns a 33.3% interest following the completion of a common unit offering on May 3, 2011.

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 2012 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, 2012 and 2011, 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 2012 and 2011 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.

On December 1, 2010, the Partnership changed its method of valuing its materials and supplies to the average cost method from the lower of cost or market value method as used in prior periods. The Partnership believes the newly adopted method is preferable. The change resulted in a $1.2 million decrease to operations and maintenance expense in 2010 on the Partnership's statements of income. There was no impact to the Partnership's cash flows.

(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 May 1, 2010 under a rate settlement approved by the FERC in July 2010, the substantial portion of the Partnership's principal operating assets are being depreciated at an annual rate of 1.48%. 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 41 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, 2012 and 2011, 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, 2012 and 2011. 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, 2012, 2011, and 2010 consists of the following:

(In thousands)	**2012**	2011	2010
Current	**$(186)**	3,238	3,474
Deferred	**–**	(5,153)	1,816
	$(186)	(1,915)	5,290

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 years ended December 31, 2011 and 2010.

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, 2012.

(b) Regulatory Matters

The Partnership has a FERC-approved settlement agreement in place. It can file for new rates at any time, but must file no later than November 1, 2013.

(c) Environmental Matters

By letter dated December 28, 2009, the U.S. Environmental Protection Agency (EPA) required the Partnership to provide information regarding its natural gas compressor stations in Minnesota, Wisconsin, and Michigan as part of the EPA's investigation of the Partnership's compliance with the Clean Air Act. On May 28, 2010, the Partnership submitted its response to the EPA and subsequently responded to a request from the EPA dated July 26, 2010 for information regarding one natural gas compressor station located in Minnesota. On May 31, 2011, the EPA required the Partnership to provide additional information regarding natural gas compressor stations in Minnesota and Michigan. The potential effects on the Partnership that may arise as a result of this information request or the underlying compliance review are not determinable at this time.

(d) Operating Leases

The Partnership leases office space under operating leases. Future minimum lease payments on the Partnership's operating leases as of December 31, 2012 were as follows (in thousands):

Year ending December 31:	
2013	$55
2014	35
2015	37
2016	9
Total	$136

(e) 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)	**2012**	2011
6.73% series Senior Notes due 2013 to 2018	**$54,000**	63,000
9.09% series Senior Notes due 2013 to 2021	**90,000**	100,000
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
	354,000	373,000
Less current maturities	**19,000**	19,000
Total long-term debt less current maturities	**$335,000**	354,000

The aggregate annual required repayment of long-term debt is $19.0 million for each year from 2013 through 2017. Aggregate required repayments of long-term debt thereafter total $259.0 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 $191.0 million of partners' capital was restricted as to distributions as of December 31, 2012. As of December 31, 2012, 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, 2012 and 2011. 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.

	2012		2011	
(In thousands)	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Financial assets:				
Cash and cash equivalents	**$31**	**31**	47	47
Financial liabilities:				
Long-term debt	**$354,000**	**535,806**	373,000	541,245

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.

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, 2012 and 2011, the Partnership had a demand loan receivable from TransCanada of $26.5 million and $36.8 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 2027.

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)	**2012**	2011	2010
Transportation revenues from affiliates	**$77,338**	80,553	148,464
Rental revenue from affiliates	**1,355**	1,316	884
Costs charged from affiliates	**32,826**	31,172	30,282

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.

In September 2010, the Partnership's distribution policy was changed to allow distributable cash flow to include debt repayments funded with partner cash calls. Previous distributable cash flow included a deduction for debt repayments without considering partner cash call funding.

On January 11, 2013, the Management Committee of the Partnership declared a cash distribution in the amount of $13.7 million to the partners. The distribution was paid on February 1, 2013.

9. SUBSEQUENT EVENTS

Subsequent events have been assessed through February 13, 2013, 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.

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, 2012 and 2011, 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, 2012, 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, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 13, 2013

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, (In thousands)	**2012**	2011
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 28,391**	$ 32,815
Accounts receivable	**26,523**	27,688
Related party receivables	**492**	638
Materials and supplies, at cost	**5,289**	5,138
Prepaid expenses and other	**2,378**	2,182
Total current assets	**63,073**	68,461
Property, plant and equipment:		
Natural gas transmission plant	**2,545,596**	2,531,592
Construction work in progress	**7,034**	940
Total property, plant and equipment	**2,552,630**	2,532,532
Less: Accumulated provision for depreciation and amortization	**1,318,759**	1,265,894
Property, plant and equipment, net	**1,233,871**	1,266,638
Other assets:		
Regulatory assets	**28,117**	28,171
Debt issuance costs	**2,764**	3,131
Other	**–**	2
Total other assets	**30,881**	31,304
Total assets	**$1,327,825**	$1,366,403
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 10,164**	$ 8,319
Related party payables	**3,589**	3,396
Accrued taxes other than income	**29,763**	28,892
Accrued interest	**6,931**	7,123
Other	**2,072**	834
Total current liabilities	**52,519**	48,564
Long-term debt, net of current maturities	**472,630**	472,601
Deferred credits and other liabilities:		
Regulatory liabilities	**14,620**	12,121
Other	**1,422**	705
Total deferred credits and other liabilities	**16,042**	12,826
Commitments and contingencies		
Partners' equity:		
Partners' capital	**789,137**	835,112
Accumulated other comprehensive loss	**(2,503)**	(2,700)
Total partners' equity	**786,634**	832,412
Total liabilities and partners' equity	**$1,327,825**	$1,366,403

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

Years Ended December 31, (In thousands)	**2012**	2011	2010
Operating revenue	**$310,869**	$310,070	$295,069
Operating expenses:			
Operations and maintenance	**55,658**	50,405	49,720
Depreciation and amortization	**63,090**	61,583	61,470
Taxes other than income	**23,069**	22,824	24,268
Operating expenses	**141,817**	134,812	135,458
Operating income	**169,052**	175,258	159,611
Interest expense:			
Interest expense	**27,547**	26,547	26,649
Interest expense capitalized	**(84)**	(210)	(60)
Interest expense, net	**27,463**	26,337	26,589
Other income (expense):			
Allowance for equity funds used during construction	**313**	479	148
Other income	**3,570**	3,367	3,165
Other expense	**(62)**	(37)	(86)
Other income, net	**3,821**	3,809	3,227
Net income to partners	**$145,410**	$152,730	$136,249

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (In thousands)	**2012**	2011	2010
Net income to partners	**$145,410**	$152,730	$136,249
Other comprehensive income:			
Changes associated with hedging transactions	**197**	183	171
Total comprehensive income	**$145,607**	$152,913	$136,420

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)	**2012**	2011	2010
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	**$ 145,410**	$ 152,730	$ 136,249
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	**63,122**	61,615	61,556
Allowance for equity funds used during construction	**(313)**	(479)	(148)
Changes in components of working capital	**922**	(4,199)	2,034
Other	**2,052**	(84)	(519)
Total adjustments	**65,783**	56,853	62,923
Net cash provided by operating activities	**211,193**	209,583	199,172
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	**(24,192)**	(29,661)	(9,861)
Net cash used in investing activities	**(24,192)**	(29,661)	(9,861)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	**–**	109,587	–
Distributions to partners	**(191,385)**	(198,110)	(171,944)
Proceeds from issuance of debt	**25,000**	74,000	97,000
Repayment of debt	**(25,000)**	(142,000)	(121,000)
Debt issuance costs	**(40)**	(815)	–
Net cash used in financing activities	**(191,425)**	(157,338)	(195,944)
Net change in cash and cash equivalents	**(4,424)**	22,584	(6,633)
Cash and cash equivalents at beginning of year	**32,815**	10,231	16,864
Cash and cash equivalents at end of year	**$ 28,391**	$ 32,815	$ 10,231
Supplemental disclosure for cash flow information:			
Cash paid for interest, net of amount capitalized	**$ 27,022**	$ 25,809	$ 26,137
Accruals for property, plant and equipment	**2,529**	–	–
Changes in components of working capital:			
Accounts receivable	**$ 1,165**	$ 3,441	$ (7,286)
Related party receivables	**146**	(362)	115
Materials and supplies	**(150)**	(828)	161
Prepaid expenses and other	**(196)**	(875)	265
Accounts payable	**(684)**	(2,206)	7,116
Related party payables	**193**	381	(375)
Accrued taxes other than income	**(597)**	(1,485)	263
Accrued interest	**(192)**	79	(14)
Other current liabilities	**1,237**	(2,344)	1,789
Total	**$ 922**	$ (4,199)	$ 2,034

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, 2009	$403,300	$403,300	$(3,054)	$ 803,546
Net income to partners	68,124	68,125	–	136,249
Changes associated with hedging transactions	–	–	171	171
Distributions paid	(85,972)	(85,972)	–	(171,944)
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**

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, 2012 and 2011 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, 2012 and 2011:

	December 31,		Remaining recovery/ settlement
	2012	2011	period
	(In thousands)		*(Years)*
Fort Peck lease option	**$13,737**	$14,097	38
Pipeline extension project	**4,152**	4,614	9
Deferred rate case expenditures	**–**	391	–
Volumetric fuel tracker	**1,359**	1,668	n/a
South Dakota use tax assessment	**8,869**	7,401	n/a
Total regulatory assets	**$28,117**	$28,171	

At December 31, 2012 and 2011, respectively, we have reflected a regulatory liability of $14.6 million and $12.1 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 2012 and 2011 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.

(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. For the years ended December 31, 2012, 2011 and 2010, our depreciation rates vary from 2.25% to 20% per year. Using these rates, the remaining depreciable life of these assets ranges from 1 to 42 years. See Note 3 for further information regarding prospective depreciation rates.

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, 2012 and 2011. We continue to evaluate our asset retirement obligations and future developments that could impact amounts our records.

(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.

As required by the provisions of the settlement of our 2005 rate case, on September 27, 2012 we filed a petition with the FERC requesting approval of a Stipulation and Agreement of Settlement (Northern Border Settlement) with our customers to modify our transportation rates. The Northern Border Settlement will be effective January 1, 2013 and eliminates our obligation to file a Section 4 rate case by December 31, 2012. 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 will be reduced to 2.19 percent from 2.40 percent, which prospectively increases the depreciable life of our assets. The settlement includes a three-year moratorium on filing rate cases or challenging the settlement rates and requires that we file for new rates no later than January 1, 2018.

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, 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. As of December 31, 2011, we had recorded $0.3 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, 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. For the year ended December 31, 2010, shippers providing significant operating revenues were Tenaska Marketing Ventures and BP Canada with revenues of $43.3 million and $41.2 million, respectively.

5. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

December 31, (In thousands)	**2012**	2011
2011 Credit Agreement – average interest rate of 1.34% at December 31, 2012 due 2016	**$123,000**	$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	**(370)**	(399)
Long-term debt	**472,630**	472,601

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, 2012, based on the principal commitment amount of $200 million, available capacity under the 2011 Credit Agreement was $77 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, 2012, we were in compliance with all of our financial covenants.

Aggregate required repayment of long-term debt for the next five years is $223 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 2013, 2014, 2015 or 2017.

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

We record in long-term debt amounts received or paid related to terminated interest rate swap agreements for fair value hedges and amortize these amounts to interest expense over the remaining original term of the interest rate swap agreements.

We record in accumulated other comprehensive income (loss) amounts received or paid related to terminated interest rate swap agreements for cash flow hedges and amortize these amounts to interest expense. The following table represents the effective portion of realized gains, net of realized losses, that have been reclassified from accumulated other comprehensive income (loss) and recognized as a reduction (increase) to interest expense on the statements of income:

Net Loss Reclassified from AOCI into Income (Effective Portion) *(In thousands)*	Statements of Income Caption	Years Ended December 31, **2012**	2011	2010
Cash flow hedges	Interest expense	**$(197)**	$(183)	$(171)

At December 31, 2012, we have realized losses recorded in accumulated other comprehensive loss of approximately $2.5 million. We expect to reclassify approximately $0.2 million from accumulated other comprehensive loss as an increase to interest expense in 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, 2012 and 2011. 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:

	2012		2011	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	**$28,391**	**$28,391**	$32,815	$32,815
Financial liabilities:				
Long-term debt	**$472,630**	**$545,098**	$472,601	$541,027

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.

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, 2012, 2011, and 2010 were $4.0 million, $2.3 million, and $1.4 million, respectively. Our future minimum lease payments are as follows:

Year ending December 31, (In thousands)	
2013	1,919
2014	1,921
2015	1,922
2016	2,198
2017	2,189
Thereafter	51,027
	$61,176

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, 2012, 2011, and 2010, we paid distributions to our general partners of $191.4 million, $198.1 million, and $171.9 million, respectively. 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, 2012, 2011, and 2010, our charges from TransCanada and its affiliates totaled approximately $30.5 million, $28.7 million, and $25.8 million, respectively.

For the years ended December 31, 2012, 2011, and 2010, 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 2012, 2011, and 2010 was $5.6 million, $4.4 million, and $4.1 million, respectively. At December 31, 2012 and 2011, we had outstanding receivables from ONEOK Energy and ONEOK Rockies of $0.5 million and $0.5 million, respectively.

11. SUBSEQUENT EVENTS

On January 17, 2013, the FERC approved the Northern Border Settlement to become effective January 1, 2013.

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $43.1 million was declared and paid on February 1, 2013 for the fourth quarter of 2012.

We have evaluated subsequent events through February 13, 2013, 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.

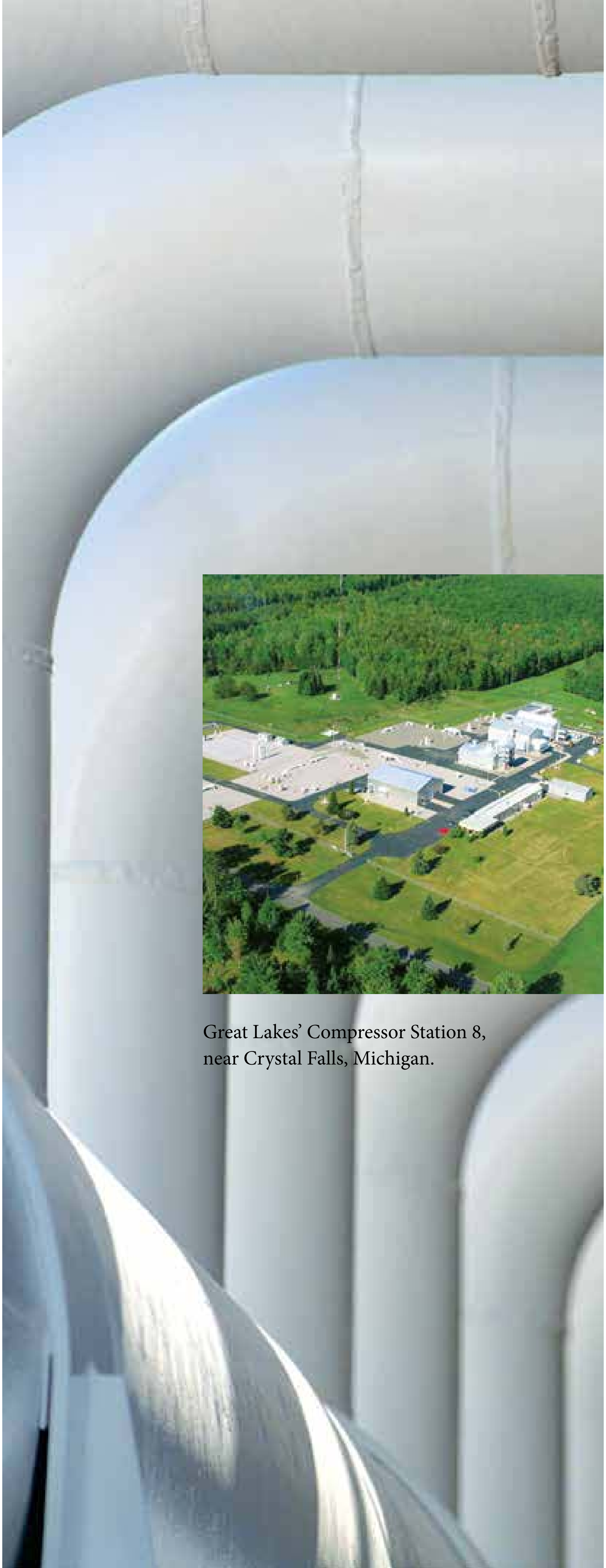
Glossary

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

2011 Credit Agreement	$200 million amended and restated revolving Credit Agreement for Northern Border
Acquisitions	The 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
Delaware Act	Delaware Revised Uniform Limited Partnership Act
DOT	U.S. Department of Transportation
DSUs	Deferred Share Units
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fracking	Horizontal drilling in combination with multi-stage hydraulic fractoring
GAAP	U.S. generally accepted accounting principles
General Partner	TC PipeLines GP, Inc.
GHG	Greenhouse Gas
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest LLC
GTN 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
MBT	Michigan Business Tax
MDth/d	Thousand dekatherms per day
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	North Baja and Tuscarora
Our pipeline systems/our pipelines	Our ownership interests in Great Lakes, Northern Border, GTN, Bison, North Baja and Tuscarora
Partnership	TC PipeLines, LP and its subsidiaries

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 revolving credit and term loan agreement
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora Settlement	Stipulation and Agreement of Settlement for Tuscarora regarding its rates and terms and conditions of service
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

Unless the context clearly indicates otherwise, TC PipeLines, LP, its subsidiaries and equity investees 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 Great Lakes Gas Transmission Limited Partnership (Great Lakes), Northern Border Pipeline Company (Northern Border), Gas Transmission Northwest LLC (GTN), Bison Pipeline LLC (Bison), North Baja Pipeline, LLC (North Baja) and Tuscarora Gas Transmission Company (Tuscarora).



Great Lakes' Compressor Station 8, near Crystal Falls, Michigan.

Corporate Information

Board of Directors of the General Partner of TC PipeLines, LP

Gregory A. Lohnes
Chairman, TC PipeLines GP, Inc.
Executive Vice-President, Operations and Major Projects
TransCanada Corporation
Calgary, Alberta

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

Kristine L. Delkus
Senior Vice-President, Pipelines Law and Regulatory Affairs, Corporate Services Division
TransCanada PipeLines Limited
Calgary, Alberta

Jack F. Jenkins-Stark [1][2][3]
Chief Financial Officer
BrightSource Energy, Inc.
Oakland, California

James (Jim) M. Baggs
Senior Vice-President, Operations and Engineering, Operations and Major Projects Division
TransCanada PipeLines Limited
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
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

Gregory A. Lohnes
Chairman

Steven D. Becker
President

Stuart P. Kampel
Vice-President and General Manager

Sandra P. Ryan-Robinson
Controller and Principal Financial Officer

Terry C. Ofremchuk
Vice-President, Taxation

William C. (Chuck) Morris
Treasurer

Annie C. Belecki
Secretary

Jon A. Dobson
Assistant Secretary

TC PipeLines, LP

Investor Relations

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Manager, Investor Relations
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On the front cover: *Gas Transmission Northwest's Station 10, near Kent, Oregon showing Mount Hood in the background.*

TC PipeLines, LP

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