TC PIPELINES LP
Form 10-K
February 26, 2010

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

FORM 10-K

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

or

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

For the Transition period from to
Commission File Number: 000-26091

TC PipeLines, LP

(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	**52-2135448** (I.R.S. Employer Identification No.)
717 Texas Street, Suite 2400 **Houston, Texas** (Address of principal executive offices)	**77002-2761** (Zip code)

877-290-2772
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common units representing limited partner interests Title of each class	**NASDAQ Stock Market** Name of each exchange on which registered

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes o   No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.   ý

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

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a small reporting company)	Smaller Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).   Yes o   No ý

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as at June 30, 2009 was approximately $839.8 million.

As of February 26, 2010, there were 46,227,766 common units of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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

Glossary

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

2007 Credit Agreement	Northern Border's $250.0 million amended and restated revolving credit agreement
Acquisition Agreement	Agreement for Purchase and Sale of Membership Interest
Alberta Hub	The grouping of gas gathering lines, processing, storage facilities in large scale and also a "liquid" pricing point recognized for trading in Alberta, Canada
ASC	Accounting Standards Codification
ANR	ANR Pipeline Company
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BIA	Bureau of Indian Affairs
Bison	Bison Pipeline LLC
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CWA	Clean Water Act
Collar Agreement	Northern Border's interest rate collar agreement
DCF	Discounted cash flow
Delaware Act	Delaware Revised Uniform Limited Partnership Act
Design capacity	Pipeline capacity available to transport natural gas based on system facilities and design conditions
Dth	Dekatherms
Dth/d	Dekatherms per day
EBITDA	Net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges
El Paso	El Paso Natural Gas Company
EPA	U.S. Environmental Protection Agency
Essar	Essar Steel Minnesota LLC
Exchange Agreement	Agreement with the general partner pursuant to which the Partnership issued new common units to the general partner and provided for Revised IDRs in exchange for the cancellation of the Old IDRs
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Gas exiting the WCSB	Net of the supply of and demand for natural gas in the WCSB region that is available for transportation to downstream markets; where supply represents WCSB production adjusted for injections into and withdrawals from WCSB storage
General Partner	TC PipeLines GP, Inc.
GL Cost and Revenue Study	Cost and Revenue study filed by Great Lakes with the FERC in response to the FERC's November 19, 2009 Order
GL Executive Committee	Executive Committee of the Great Lakes Management Committee

GL Management Committee	Great Lakes Management Committee
GL Rate Proceeding	FERC investigation into Great Lakes' rates pursuant to Section 5 of the NGA
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest Corporation
IDRs	Incentive Distribution Rights
INGAA	Interstate Natural Gas Association of America
IRS	Internal Revenue Service
LDCs	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
MBT	Michigan Business Tax
MDth/d	Thousand dekatherms per day
MLP	Master Limited Partnership
MMcf/d	Million cubic feet per day
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
NOV	Notice of Violation
November 2009 Order	FERC order issued in FERC Docket No. RP10-149 on November 19, 2009 instituting GL Rate Proceeding
Offering	The sale of 2,609,680 newly issued, unregistered common units representing limited partner interests in the Partnership to TransCan Northern at a price per common unit of $30.042 for an aggregate amount of approximately $78.4 million
Old IDRs	IDRs available to the general partner under the Amended and Restated Agreement of Limited Partnership
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners GP	ONEOK Partners GP, LLC
Other Pipes	North Baja and Tuscarora
Our pipeline systems	Great Lakes, Northern Border, North Baja and Tuscarora
Paiute	Paiute Pipeline Company
Partnership	TC PipeLines, LP and its subsidiaries
Partnership Agreement	Second Amended and Restated Agreement of Limited Partnership
RCRA	Resource Conservation and Recovery Act
Revised IDRs	IDRs available to the general partner under the Second Amended and Restated Agreement of Limited Partnership
REX	Rockies Express Pipeline
ROE	Return on equity
Ruby	Ruby Pipeline LLC

SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines' revolving credit and term loan agreement
SFAS	Statement of Financial Accounting Standards
Sierra Pacific Power	Sierra Pacific Power Company, a subsidiary of NV Energy Inc. (formerly known as Sierra Pacific Resources)
TCILP	TC PipeLines Intermediate Limited Partnership, a subsidiary of the Partnership
TransCan Northern	TransCan Northern Ltd.
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin
Yuma Lateral	An expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona

PART I

FORWARD-LOOKING STATEMENTS

The statements in this report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "forecast" and other words and terms of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking.

These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors that could cause actual results to differ materially from those contemplated in the forward-looking statements include:

- the ability of Great Lakes Gas Transmission Limited Partnership (Great Lakes) and Northern Border Pipeline Company (Northern Border) to continue to make distributions at their current levels;
- the impact of unsold capacity on Great Lakes and Northern Border being greater or less than expected;
- competitive conditions in our industry and the ability of Great Lakes, Northern Border, North Baja Pipeline, LLC and Tuscarora Gas Transmission Company (together "our pipeline systems") to market pipeline capacity on favorable terms, which is affected by:
  - future demand for and prices of natural gas;
  - level of natural gas basis differentials;
  - competitive conditions in the overall natural gas and electricity markets;
  - availability and relative cost of supplies of Canadian and United States (U.S.) natural gas, including the recently discovered shale gas resources such as the Horn River and Montney deposits in Western Canada, along with U.S. Rockies, Mid-Continent, and Marcellus gas developments;
  - competitive developments by U.S. and Canadian natural gas transmission companies;
  - the availability of additional storage capacity and current storage levels;
  - the level of liquefied natural gas imports;
  - weather conditions that impact supply and demand; and
  - the ability of shippers to meet credit worthiness requirements;
- the impact of current and future laws, rulings and governmental regulations, particularly Federal Energy Regulatory Commission regulations and rate proceedings, and proposed and pending legislation by Congress and proposed and pending regulations by the U.S. Environmental Protection Agency on us and our pipeline systems;
- changes in relative cost structures of natural gas producing basins, such as changes in royalty programs, that may prejudice the development of the Western Canada Sedimentary Basin;

decisions by other pipeline companies to advance projects which will affect our pipeline systems and the regulatory, financing and construction risks related to construction of interstate natural gas pipelines and additional facilities;

the ability of our pipeline systems to identify and/or consummate expansion projects which are accretive growth opportunities for the Partnership;

performance of contractual obligations by customers of our pipeline systems;

the imposition of entity level taxation by states on partnerships;

operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;

- the Partnership's ability to identify and/or consummate accretive growth opportunities from TransCanada Corporation or others;

- our ability to control operating costs and the ability of TransCanada to implement its reorganization of U.S. pipeline operations, including the operations of our pipeline systems, and realize cost savings; and

- general economic conditions in North America, which impact:

  - the debt and equity capital markets and our ability to access these markets at reasonable costs;

  - the overall demand for natural gas by end users; and

  - natural gas prices.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. Please also read 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. These forward-looking statements and information are made only as of the date of the filing of this report, and except as required by applicable law, we undertake no obligation to update these forward-looking statements and information to reflect new information, subsequent events or otherwise.

Item 1. Business

OVERVIEW

We are a publicly traded Delaware limited partnership formed in 1998 by TransCanada PipeLines Limited to acquire, own and participate in the management of energy infrastructure businesses in North America. Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

TC PipeLines, LP and its subsidiaries are collectively referred to herein as "the Partnership". In this report, references to "we", "us" or "our" refer to the Partnership. TransCanada PipeLines Limited is a wholly-owned subsidiary of TransCanada Corporation (which, together with its subsidiaries, is referred to as TransCanada).

The general partner of the Partnership is TC PipeLines GP, Inc., a wholly-owned subsidiary of TransCanada.

To date, our investments have been in interstate natural gas pipeline systems that transport natural gas to a variety of markets in the United States, Eastern Canada and Mexico.

- We own a 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). The remaining 53.55 per cent interest in Great Lakes is held by TransCanada.

- We own a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border). The other 50 per cent interest is held by ONEOK Partners, L.P. (ONEOK Partners), a publicly traded limited partnership that is controlled by ONEOK, Inc.

- We own 100 per cent of North Baja Pipeline, LLC (North Baja), which we acquired on July 1, 2009 from TransCanada. Please read "Year in Review 2009" within this section for additional information regarding the North Baja acquisition.

- We own 100 per cent of Tuscarora Gas Transmission Company (Tuscarora).

We believe our strong financial position, including available unused capacity on our credit facility, gives us the capacity to pursue opportunities to grow in a sustained and disciplined manner for the long-term benefit of our unitholders.

TransCanada operates Great Lakes, Northern Border, North Baja and Tuscarora (collectively, "our pipeline systems"). See Item 13. "Certain Relationships and Related Transactions, and Director Independence".

Year in Review 2009

Partnership

Public Equity Issuance

On November 18, 2009, the Partnership completed a public offering of 5,000,000 common units at a price of $38.00 per unit for net proceeds of approximately $185 million, including the capital contribution of approximately $4 million from our general partner to maintain its two per cent general partner interest. The proceeds were used to repay debt outstanding under our revolving credit facility.

North Baja Acquisition

On July 1, 2009, the Partnership acquired 100 per cent of North Baja from TransCanada for a purchase price of approximately $271 million. The acquisition was financed through a combination of a private equity issuance, a draw on the Partnership's credit facility and cash on hand. The private equity issuance resulted in 2,609,680 common units issued to a wholly-owned subsidiary of TransCanada at $30.042 per common unit.

The Partnership agreed to acquire an expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona (Yuma Lateral) if TransCanada completed the expansion by June 30, 2010. See "Business of North Baja" within this section for an update with respect to the Yuma Lateral.

Incentive Distribution Right (IDR) Restructuring

Concurrent with the acquisition of North Baja, the Partnership entered into an exchange agreement (Exchange Agreement) with its general partner whereby the Partnership issued 3,762,000 new common units to the general partner and provided revised incentive distribution rights (Revised IDRs) in exchange for the cancellation of the incentive distribution rights available to the general partner (Old IDRs) under the Partnership's Amended and Restated Agreement of Limited Partnership.

Under the terms of the Revised IDRs, the distributions to the general partner were reset to two per cent, down from the general partner distribution levels of the Old IDRs at 50 per cent (for combined general partner interest and incentive distribution interest). The incentive distribution levels of the Revised IDRs will result in increased combined distributions to the general partner (for general partner interest and incentive distribution interest) of 15 per cent and a maximum of 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit, or $3.24 and $3.52 per common unit on an annualized basis, respectively.

Partnership Agreement Amended and Restated

As part of the Exchange Agreement, the Partnership's Amended and Restated Agreement of Limited Partnership was amended and restated effective July 1, 2009 to reflect the Revised IDRs as described above.

Our Pipeline Systems

Great Lakes Rate Proceeding

On November 19, 2009, the Federal Energy Regulatory Commission (FERC) instituted proceedings under Section 5 of the Natural Gas Act to review the tariff rates of Great Lakes. As directed under the November 2009 FERC Order, Great Lakes filed a cost and revenue study on February 4, 2010. See "Regulatory Environment, Government Regulation" within this section and also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information with respect to this proceeding.

Great Lakes Contract Renewal

On November 3, 2009, Great Lakes and TransCanada extended contracts until October 31, 2011 for 470 thousand dekatherms per day (MDth/d) of long haul capacity, which would have expired on October 31, 2010. Great Lakes has 486 MDth/d of long haul capacity and an additional 110 MDth/d of short haul capacity under contracts expiring on October 31, 2010. See "Contracting" within this section for more information with respect to Great Lakes' contracting position.

Northern Border Des Plaines Project

Northern Border's Des Plaines compressor station and interconnect facilities project went into service in March 2009, with a final cost to Northern Border of approximately $17 million.

Business Strategies

Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

We seek opportunities to undertake accretive acquisitions and pursue organic growth projects through our pipeline systems to maximize the value of our existing portfolio of investments. Working with our partners in our pipeline systems, we seek to pursue policies that:

- maximize the utilization of our pipeline systems;
- expand our pipeline systems to meet market demand and increase supply diversity; and
- promote safe and efficient operations.

We intend to support the execution of our business strategies by:

- maintaining a strong and balanced financial position to:
  - maintain a prudent level of available cash for distribution to unitholders;
  - fund future growth; and
  - broaden our asset base in a disciplined and focused manner;
- investing in energy infrastructure businesses in North America that are underpinned by strong business fundamentals and provide stable cash flows; and
- maximizing the benefits of our relationship with TransCanada.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- Our pipeline systems hold strategic market positions and, except for North Baja, comprise critical links for the transportation of natural gas from the Alberta Hub in Canada to U.S. markets. The Alberta Hub is one of the largest natural gas hubs in North America. Additional natural gas supply from the Alberta Hub is expected to be available in the future when new pipeline projects associated with the Montney and Horn River shale deposits in Western Canada are constructed, or if the longer-term potential associated with the proposed development of the Mackenzie Delta in Northern Canada and the North Slope in Alaska is realized;
- With TransCanada as operator of our pipeline systems, we believe our pipeline systems are well positioned to continue to operate as trusted and experienced transportation service providers; and

The senior management team and the board of directors of our general partner have extensive industry experience and include some of the most senior officers of TransCanada. The management team plays a significant role in developing the strategic direction of our pipeline systems and their associated operations, and we believe our ability to execute our business strategies is enhanced by our affiliation with TransCanada.

Our Relationship with TransCanada

One of our principal strengths is our relationship with TransCanada. TransCanada, a Canadian corporation, was founded in 1951 with the objective of transporting natural gas from Alberta, Canada to distant markets. Today, TransCanada is a major North American energy infrastructure company engaged in numerous aspects of the energy industry but is primarily focused on natural gas and oil transmission and power generation services. TransCanada owns, including assets that are under construction or in development, approximately 37,300 miles of wholly-owned natural gas pipelines and interests in an additional 5,500 miles of natural gas pipelines, along with approximately 380 billion cubic feet (Bcf) of storage capacity and, including facilities that are under construction or in development, also owns, operates, and/or controls over 11,700 megawatts of power generation. TransCanada is also constructing the Keystone oil pipeline which will be approximately 3,800 miles in length.

TransCanada provides access to a significant pool of management talent and strong relationships throughout the energy industry. We expect to pursue strategic acquisitions in a disciplined manner and to have the opportunity to participate jointly with TransCanada in reviewing potential acquisitions, including transactions that we would be unable to pursue on our own. Additionally, we may have the opportunity to make acquisitions directly from TransCanada. 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 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.

Our Partnership Structure

The following chart depicts our organizational and ownership structure.

(1) Through subsidiary companies.

(2) Effective aggregate economic interest.

Our Pipeline Systems

All of our pipeline systems are regulated by the FERC. Operating revenue is derived from the transportation of natural gas. The maximum transportation rates that our pipeline systems may charge are approved by the FERC, and in most cases, established in a FERC proceeding known as a rate case. During a rate case, a determination is reached by the FERC, either through a hearing or a settlement, on the maximum rates permissible for transportation service on a pipeline system that include the recovery of cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set, the pipeline system is not permitted to adjust the maximum rates to reflect changes in costs or contract demand until new rates are approved by the FERC, usually after a rate case has been filed. The FERC also governs the general terms and conditions for natural gas transportation service on interstate natural gas pipelines. The tariff also allows for services to be provided under negotiated and discounted rates. As a result, earnings and cash flow of each pipeline system depend on costs incurred; contracted capacity and transportation path; the volume of gas transported; and the ability of each system to sell capacity at acceptable rates.

Transportation Services

Our pipeline systems' transportation contracts include specifications regarding the receipt and delivery of natural gas at points along the pipeline system. The transportation services provided by our pipeline systems are generally categorized as firm or interruptible. The type of transportation contract, either for firm or interruptible service, determines the basis upon which each customer is charged.

Customers with firm service transportation agreements pay a fee known as a reservation charge to reserve pipeline capacity, regardless of use, for the term of their contracts. On the Great Lakes, Northern Border and North Baja systems, firm service transportation customers also pay a variable usage fee known as a commodity charge (or utilization fee) that is generally based on distance and the volume of natural gas they transport.

Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges (or utilization fees) based on distance and the volume of natural gas they transport. On the Great Lakes and Tuscarora systems, interruptible revenues are generally subject to a sharing mechanism whereby 90 per cent of the revenue is refunded to firm shippers paying maximum tariff rates. Our Northern Border and North Baja pipeline systems are not subject to sharing mechanisms with their shippers on their interruptible revenues.

Variable usage fees for Northern Border include a compressor usage surcharge to recover the cost of the electric compression and fuel use tax which relates to both firm and interruptible transportation services.

The table below provides information with respect to tariff revenue composition for each of our investments for the year ended December 31, 2009. It is provided to indicate the extent to which the revenue for our pipeline systems is dependent upon fixed versus variable fees.

		2009 Tariff Revenue Composition		
		Firm Contracts		
	Our Ownership Interest	Capacity Reservation Charges	Variable Usage Fees	Interruptible Contracts & Other Services
Great Lakes	46.45%	97%	2%	1%
Northern Border	50%	85%	10%	5%
North Baja	100%	97%	2%	1%
Tuscarora	100%	100%	0%	0%

Business of Great Lakes

Great Lakes is a Delaware limited partnership formed in 1990. The Partnership acquired its 46.45 per cent general partner interest in Great Lakes in February 2007.

Great Lakes receives natural gas from an interconnection with the TransCanada Mainline system at the Canadian border near Emerson, Manitoba, Canada and extends across Minnesota, Northern Wisconsin and Michigan, and redelivers gas to TransCanada at the Canadian border near Sault Ste. Marie, Ontario, Canada and St. Clair, Ontario, Canada. Great Lakes also connects to storage centers in Michigan and interconnects with other interstate natural gas pipelines.

The pipeline system consists of approximately 2,115 miles of pipeline with diameters ranging from 10 inches to 36 inches and a design capacity of 2,500 million cubic feet per day (MMcf/d) during the winter and 2,300 MMcf/d during the summer. Annual capacity is determined by the summer design capacity. Great Lakes has 14 compressor stations with a total of 438,000 horsepower and measurement facilities to support the 58 receipt and delivery points on the system.

The original construction of the Great Lakes system occurred in 1967 and 1968. Numerous capacity system expansions have occurred since its original construction, the last one completed in 1998.

The major policies of Great Lakes are established by the management committee of Great Lakes (GL Management Committee). The current GL Management Committee consists of four appointed members, two of whom are designated by us and two of whom are designated by TransCanada. All decisions by the GL Management Committee require unanimous consent. For the day to day management of Great Lakes' business, the GL Management Committee established an executive committee (GL Executive Committee). The GL Executive Committee currently consists of two appointed members: one Partnership GL Management Committee member, and one TransCanada GL Management Committee member, who also serves as the president of Great Lakes. The GL Executive Committee has all of the powers of the GL Management Committee in the management of Great Lakes' business.

Business of Northern Border

Northern Border is a Texas general partnership formed in 1978. The Partnership had a 30 per cent general partner interest in Northern Border at its initial public offering and acquired an additional 20 per cent general partner interest in April 2006.

Northern Border transports natural gas from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota, and the Powder River Basin of Wyoming and Montana, as well as synthetic gas produced at the Dakota Gasification plant in North Dakota.

The pipeline system consists of 1,249 miles of pipeline with diameters ranging from 30 to 42 inches and a design capacity on the largest segment of the pipeline of 2,374 MMcf/d. Northern Border has 18 compressor stations with a total of approximately 517,000 horsepower, measurement facilities to support the 65 receipt and delivery points on the system.

Construction of Northern Border's system was initially completed in 1982, followed by expansions or extensions in 1991, 1992, 1998, 2001 and 2006.

Northern Border is managed by a management committee that consists of four members. Each partner designates two members, and the Partnership designates one of our members as Chairman. Each partner holds a 50 per cent voting interest on the management committee.

Des Plaines Project The compressor station and interconnect facilities project went into service in March 2009, with a final cost to Northern Border of approximately $17 million. The project is fully subscribed under a 10 year compression and transportation contract. The new contract generates approximately $3 million in annual revenue for Northern Border.

Business of North Baja

North Baja is a Delaware limited liability company formed in 2000. The Partnership acquired 100 per cent of North Baja on July 1, 2009 from TransCanada.

North Baja transports natural gas between an interconnection with El Paso Natural Gas Company (El Paso) near Ehrenberg, Arizona and an interconnection near Ogilby, California on the California/Mexico border with the Gasoducto Bajanorte natural gas pipeline system which is owned by Sempra Energy International. North Baja is a bi-directional system which allows it to accept receipts and make deliveries of natural gas at both interconnection points with connecting pipelines.

The pipeline system consists of 80 miles of pipeline with diameters of 30 and 36 inches and a FERC licensed capacity of 500 MMcf/d for southbound transportation and a design capacity of 600 MMcf/d for northbound transportation. There is one compressor station at the north end of the pipeline with a limit of 21,600 horsepower. The metering points at both ends of the pipeline act as either receipt or delivery points depending on the direction of flow.

The North Baja pipeline system was initially placed into service in 2002. An expansion was completed in April 2008 to allow for bi-directional gas flow. To date, all gas flows have been southbound.

Yuma Lateral Project At the time of our acquisition of North Baja, TransCanada had begun an expansion project of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona. We agreed to acquire the expansion facilities and contracts for an additional sum up to $10 million, if TransCanada completed the project by June 30, 2010. The Yuma Lateral project is currently under construction and is expected to be completed in March 2010. The purchase price has yet to be determined.

Business of Tuscarora

Tuscarora is a Nevada general partnership formed in 1993. The Partnership acquired 49 per cent of Tuscarora in September 2000, followed by an additional 49 per cent in December 2006, and the final two per cent in December 2007.

Tuscarora originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs southeast through Northeastern California and Northwestern Nevada. Tuscarora's pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada.

The pipeline system consists of 240 miles of pipeline with a diameter of 20 inches and a design capacity of approximately 230 MMcf/d. Tuscarora has three compressor stations with a total of over 17,100 horsepower, and measurement facilities at one receipt point and 16 delivery points.

The Tuscarora pipeline system was initially placed into service in 1995, followed by expansions or extensions in 2001, 2002, 2005 and 2008.

NATURAL GAS INDUSTRY OVERVIEW

North American Natural Gas Flows

Natural gas is transported from producing regions and Liquefied Natural Gas (LNG) import facilities to market hubs for distribution to natural gas consumers. The main producing regions in North America are the Gulf of Mexico, Western Canada Sedimentary Basin (WCSB), Mid-Continent, Rockies, Permian basin, and San Juan basin. The largest consuming regions are the Northeastern U.S. and the Midwest. Recent increases in the development of unconventional and shale gas have resulted in increases in overall North American natural gas production and increased reserves. Over the past two years, significant new pipeline infrastructure has been added to move gas from producing regions to market areas, including the Rockies Express Pipeline (REX) which transports gas from the Rockies to Ohio. New interstate natural gas pipelines sourcing supply basins in the Mid-Continent, along with the completion of REX, have increased the supply of natural gas into Eastern markets. As a result, the level of competition in these market regions from alternate sources of supply has increased and caused a general reduction in basis differential between producing and market regions. This impacts the transportation value on pipelines, including our pipeline systems. Additional pipeline projects have been proposed, including projects to move additional gas supply into western market regions, which are expected to continue to impact overall North American natural gas flows. Additionally, development of new producing regions, such as the Marcellus shale in the eastern U.S., will also impact North American natural gas flows.

Demand

North America

Demand for natural gas transportation service on a pipeline system is directly related to demand for natural gas in the markets served by that system. Factors that may impact demand for natural gas include:

- weather conditions;
- economic conditions;
- government regulation;
- the availability and price of alternative energy sources versus availability and price of natural gas;
- natural gas storage inventories for the markets served;
- fuel conservation measures; and
- technological advances in fuel economy and energy generation devices.

Some of the factors have an immediate impact on natural gas demand, while others are longer term. Natural gas demand fluctuates from year to year, as well as seasonally, as a result of the factors described above. North American demand for natural gas declined in 2009 with the economic downturn. We expect that demand in 2010 will be relatively unchanged but will increase in the long term as economic growth returns. The relative environmental merits of natural gas versus other carbon based forms of energy are also expected to increase the demand for natural gas. The impact of natural gas demand on the demand for natural gas transportation service on any one pipeline system will depend upon changes in demand for natural gas in the market areas which that pipeline serves.

Other factors that may impact demand for natural gas transportation service on any one system include:

- the availability of natural gas supply at the pipeline system's receipt points;
- the ability and willingness of natural gas shippers to utilize that pipeline system over alternative pipelines;
- the relative transportation rates; and
- the volume of natural gas delivered to the markets supplied by that system from other supply sources and storage facilities.

These factors, and the impact on our pipeline systems, are discussed further under "Supply" and "Customers, Competition, and Contracting".

Our pipeline systems are exposed to risk when marketing available capacity. This occurs when existing transportation contracts expire and when there is available capacity on the pipeline system. Customers with expiring contracts can, depending on the market, either extend their contract commitments, renegotiate for shorter terms and/or discounted rates, or they may choose not to renew their contract. Customers with competitive alternatives analyze the market price spread, or basis differential, between receipt and delivery points along the pipeline to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay and the transportation routes they choose to ship their gas. Depending on supply and market conditions, a customer can contract for long-term firm transportation, short-term firm transportation, or interruptible transportation services.

Our Pipeline Systems

Contracted capacity and system throughput are measures of demand for natural gas transportation services. The trend in the amount of design capacity that is contracted gives an indication of the trend in revenue generation. The trend in system throughput generally gives an indication of the extent to which design capacity is being utilized. The table below provides historical information on the average throughput and contracted capacity as a percentage of design capacity for our pipeline systems from the past three years:

Year Ended December 31	2009	2008	2007
Contracted Capacity[a] *Average Throughput (MMcf/d)*			
Great Lakes[b]	**100%**	100%	100%
	1,992	*2,143*	*2,270*
Northern Border	**68%**	90%	97%
	1,708	*2,041*	*2,247*
North Baja[c]			
Southbound	**79%**	88%	95%
Northbound	**64%**	53%	n/a
	257	*278*	*247*
Tuscarora	**99%**	98%	96%
	93	*82*	*77*

(a) Contracted capacity percentage is calculated based upon contracted capacity compared to design capacity for Northern Border, North Baja northbound transportation and Tuscarora, compared to average design capacity for Great Lakes, and compared to FERC licensed capacity for North Baja southbound transportation.

(b) The average throughput for Great Lakes includes periods prior to the February 22, 2007 acquisition by us of a 46.45 per cent general partner interest in Great Lakes.

(c) Due to North Baja's bi-directional nature, it can contract for both southbound and northbound capacity separately. North Baja's ability to provide northbound transportation services commenced April 2008, but as there have been no northbound gas flows to date, average throughput reflects only southbound deliveries.The average throughput for North Baja includes periods prior to the July 1, 2009 acquisition by us of a 100 per cent interest in North Baja.

Great Lakes provides transportation services to Midwest and Northeast U.S. markets, as well as Eastern Canadian markets. The transportation services provided by Great Lakes are principally related to storage injection and withdrawal activity from storage centers in Michigan and Ontario as Great Lakes provides a critical link between these storage centers and consuming markets. Demand for natural gas in the markets served by Great Lakes declined in 2009 due to the economic environment's negative impact on industrial and electric generation demand. However, this demand is expected to recover slowly in the near term and grow over the long term, primarily due to the anticipated growth in demand for natural gas fired power generation. Demand for transportation services on Great Lakes remained relatively constant until 2009 when high storage levels and the economic recession dampened demand for Great Lakes transportation services. Underutilization of contracts reflected the reduced demand for transportation from Canadian supply sources during 2009. This is discussed further under "Customers, Competition and Contracting".

Northern Border provides transportation services to Midwest U.S. markets directly and through major interconnections with other interstate natural gas pipelines at Ventura and Harper, Iowa and the Chicago market hub. Demand for natural gas in the markets served by Northern Border was negatively impacted by the economic environment in 2009 and although these impacts may continue into 2010, overall demand for natural gas is expected to grow over the long term. Demand for transportation on Northern Border decreased in 2008 as a result of new volumes of natural gas being delivered to its Ventura market area from the Rockies basin by a competing pipeline. The new supply volumes moved from the Ventura market area further east with the completion of REX in 2009 and natural gas prices at Ventura improved, which improved market conditions for Northern Border at Ventura. Additional supply into Eastern markets from new pipeline projects which went into service in 2009, including the completion of REX, resulted in other supplies being displaced into the Chicago market. Demand for WCSB natural gas supply in the Chicago market has subsequently declined, resulting in reduced demand for transportation to Chicago on the eastern leg of Northern Border's system in 2009. This is discussed further under "Customers, Competition and Contracting".

North Baja was initially constructed to provide transportation services to markets in northern Baja California, Mexico through its interconnection with Gasoducto Bajanorte. Demand for natural gas in this market has been relatively flat over the past three years but is expected to grow over the long term. Demand for transportation services on North Baja is expected to grow slowly over time as new loads develop in Mexico that prefer to be served by U.S sourced gas. The facility modifications (bi-directional capability) that were completed in April 2008 enable North Baja to serve natural gas demand in the southwestern U.S. through northbound transportation services when the Energia Costa Azul LNG terminal receives LNG cargos. Although long-term contracts for northbound and southbound transportation services do not fully contract the pipeline capacity, the bi-directional capabilities of the system result in a continued high demand for transportation services on the North Baja pipeline system.

Tuscarora provides transportation services to markets in Oregon, Northern California and Northern Nevada. Demand for natural gas in these markets has grown over the last three years due primarily to increased demand from electric generation companies and local distribution companies (LDCs). The major shippers on Tuscarora's system require transportation capacity to meet their obligations to their customers but are not necessarily required to flow any gas through the system. As a result, Tuscarora's throughput is not indicative of its revenue generation. This is discussed further under "Customers, Competition and Contracting".

Seasonality

North America

North American demand for natural gas is seasonal. In general, demand tends to be higher in the winter months for heating requirements and in the summer for power generation demand to meet increased air conditioning or cooling requirements. The winter season is considered to be November through March, and the peak summer season is considered to be July through September. Weather conditions throughout North America can significantly impact regional natural gas supply and demand. Moderate winter and summer temperatures can lead to a decline in the demand for transportation service due to reduced demand for natural gas.

The North American natural gas industry uses natural gas storage to balance the impacts of relatively steady natural gas supply with the seasonality of demand for natural gas. In the spring and fall, when there is less demand for heating and cooling requirements, gas continues to be shipped through pipelines and is put into storage near market areas and in producing regions for future use. Available storage capacity combined with price spreads between current and future pricing during certain periods of the year may make it more profitable to store the gas for use in the future when the price for natural gas may be more favorable.

Gas in storage in producing regions, such as the WCSB, may impact the supply of natural gas for transportation to market areas. During periods of storage injection, there will be less supply available for transportation to market areas. Conversely, storage withdrawal provides additional supplies of natural gas for transportation to markets.

Gas in storage near market areas also impacts the demand for transportation services. Transportation services are required to transport the natural gas from producing regions to the market area. When the natural gas is in storage near the market area, the transportation required to meet market demand is reduced.

Levels of natural gas in storage in North America have been growing over the past three years and were at five year highs at the end of 2009. As inventory levels in storage fields approach maximum capacity, the demand for additional natural gas and associated transportation services is reduced. Market areas are less dependent upon supply from producing regions to meet short-term demand when there is adequate natural gas stored nearby.

The revenue associated with capacity that is contracted under long-term firm contracts is not impacted by seasonal throughput variations. The amount of uncontracted (or available) transportation capacity as well as transportation capacity under short-term contracts on a pipeline system determines the extent to which seasonal demand will impact a pipeline system's revenue. Revenues for pipeline systems that have a higher ratio of long-term contracts (contracts with a duration of at least one year) will be impacted less by seasonal demand. Conversely, for those pipeline systems with more available capacity, or operating under short-term contracts, fluctuations in demand between seasons can impact revenue. Additionally, a pipeline can generate revenue with interruptible or daily sales of available capacity if a firm transportation customer does not utilize all of their contracted capacity. Pipeline systems which have a tariff that includes seasonal rates for short-term service may be able to mitigate the potential negative impact of seasonal fluctuations in demand.

Our Pipeline Systems

Great Lakes Great Lakes' design day capacity at the receipt point near Emerson, Manitoba is approximately 2.5 billion cubic feet per day (Bcf/day) during the winter due to the ability to increase flow through gas turbine driven compressors during periods of low ambient temperatures and 2.3 Bcf/day during the summer when ambient temperatures are higher.

The transportation value across the Great Lakes pipeline system is normally at its highest in conjunction with storage fill requirements and electric power generation demand. Great Lakes is connected to approximately 880 Bcf of working gas storage located at the Eastern end of the Great Lakes system in Michigan and Ontario, Canada. The demand for Great Lakes' long haul transportation service is normally at its highest when natural gas is being delivered to storage areas. The high demand period usually begins in the spring and extends through most of the summer. High levels of natural gas in storage throughout 2009 reduced the demand for Great Lakes' transportation services to fill market storage.

During the winter, there is also strong demand for Great Lakes' services to meet the peak winter heating demand requirements of Northern Minnesota, Northern Wisconsin and Michigan. These deliveries are met through Great Lakes' short haul, long haul, and backhaul transportation services from storage fields in Michigan and Ontario, Canada.

Great Lakes experiences significant winter volatility in the utilization of its long haul transportation contracts due to downstream constraints on the Union Gas Limited and TransCanada pipeline systems. When there are increases in natural gas withdrawn from the Eastern Michigan and Ontario, Canada storage fields to serve U.S. Northeast and Eastern Canadian markets, constraints increase on downstream pipelines. These constraints may reduce shippers' ability to use Great Lakes' transportation services to serve Eastern markets and may reduce demand for Great Lakes' transportation services during certain peak winter periods.

Approximately 90 per cent of Great Lakes' average design capacity was contracted on a long-term firm basis in 2009, compared to 89 per cent in 2008. As a result, Great Lakes had limited exposure to fluctuations in revenue due to seasonality. Reductions in the level of capacity under long-term contracts will increase exposure to fluctuations in revenue from seasonal and short-term demand for transportation services. See further discussion under "Contracting" in this section for changes to Great Lakes' contracting profile.

Northern Border Demand for Northern Border's transportation services has traditionally been the strongest during peak winter months to serve heating demand and peak summer months to serve electric cooling demand and storage injection.

Approximately 42 per cent of Northern Border's design capacity was contracted on a long-term firm basis in 2009, compared to 65 per cent in 2008. As a result, Northern Border has increased exposure to fluctuations in revenue due to seasonal demand factors.

Some of Northern Border's exposure may be mitigated by its seasonal rate structure for short-term service that provides for higher maximum rates during anticipated peak usage periods and lower maximum rates during anticipated periods of reduced demand. Approximately 27 per cent of Northern Border's design capacity was contracted on a short-term basis in 2009 compared to 24 per cent in 2008.

North Baja and *Tuscarora* Seasonal fluctuations in revenue are minimal for these pipeline systems because their capacity is contracted on a long-term basis. See further discussion under "Contracting" in this section.

Supply

North America

The primary source of natural gas transported by our pipeline systems, except North Baja, is the WCSB. For this reason, the continuous supply of Canadian natural gas is crucial to the long-term financial condition of our pipeline systems.

The WCSB has remaining discovered natural gas reserves of approximately 61 trillion cubic feet and a reserves-to-production ratio of approximately 11 years at current levels of production. Supply from the WCSB has declined in recent years due to reduced drilling activity in the basin related to lower natural gas prices, higher supply costs, including higher royalties, and competition for capital from other North American gas production basins that have lower exploration costs. Drilling in the WCSB is expected to recover in the ensuing years assuming that gas prices stabilize and that exploration and development costs become more economical.

The net amount of natural gas exiting the WCSB is a significant factor affecting the volume of natural gas transported by our pipeline systems, except North Baja. "Gas exiting the WCSB" is the term we use to represent the net of the supply of and demand for natural gas in the WCSB region. WCSB supply is made up of WCSB production with injections into WCSB storage reducing net supply, and withdrawals from WCSB storage increasing supply. Gas exiting the WCSB is determined by:

- WCSB natural gas production levels;
- Western Canadian demand for WCSB natural gas; and
- Western Canadian storage capacity for WCSB natural gas and demand for storage injection.

The extent to which gas exiting the WCSB will be transported on each pipeline system is affected by:

- demand for WCSB natural gas in various U.S. consumer markets;
- available transportation capacity and related market pricing options on our competitors' pipelines;
- natural gas from other supply sources that can be transported to our customer markets;
- the natural gas market price spread between the Alberta Hub in Canada and the applicable downstream market which reflects the relative supply of and demand for WCSB natural gas in Canada and in the U.S.; and
- storage capacity in the U.S. and Canada and the related demand for storage injection or withdrawal.

Our Pipeline Systems

Great Lakes receives natural gas primarily from its interconnection with the TransCanada Mainline pipeline system. Gas received from the interconnection with the TransCanada Mainline pipeline system near Emerson, Manitoba, Canada is WCSB supply. Great Lakes also transports natural gas from its interconnection with TransCanada's ANR pipeline system (ANR) and from storage facilities. ANR is interconnected with numerous other pipelines, primarily sourcing gas from the Gulf of Mexico and Mid-Continent regions. The gas received from Great Lakes' interconnection with ANR accounted for approximately 12 per cent of the natural gas Great Lakes transported in 2009.

Northern Border receives natural gas primarily from its interconnection with one of TransCanada's pipelines at the Canadian border near Port of Morgan, Montana. Gas received from this interconnection is WCSB supply. Northern Border also transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana, which accounted for approximately

11 per cent of the natural gas Northern Border transported in 2009. Synthetic gas produced at the Dakota Gasification plant in North Dakota accounted for another approximately eight per cent of the natural gas transported by Northern Border in 2009.

TransCanada is pursuing the Bison Pipeline Project, which is a proposed new interstate natural gas pipeline extending from the Powder River Basin producing region in Wyoming to an interconnection with the Northern Border system in Morton County, North Dakota. The FERC issued a Final Environmental Impact Statement in December 2009 and the project is in the final stages of the regulatory process. Pending these approvals, TransCanada expects to commence construction in May 2010 and expects to place the project into service in late 2010. If completed, this project would bring approximately 407 MMcf/d of additional supply from the Powder River Basin to Northern Border, which would increase Northern Border's supply diversity.

North Baja receives natural gas from its interconnections with El Paso, which is primarily gas originating from the West Texas or Southern Rocky Mountain supply regions, and Gasoducto Bajanorte, which would originate from the Costa Azul LNG facility in Mexico. To date, no gas has been transported on North Baja from its interconnection with Gasoducto Bajanorte.

Tuscarora receives natural gas from its interconnection with GTN. GTN is interconnected with WCSB supply as well as natural gas from the Rockies and other U.S. basins. A second interstate pipeline with the potential to interconnect to Tuscarora, Ruby Pipeline LLC (Ruby), is currently under development. If Ruby is constructed, it will increase Tuscarora's access to natural gas from the Rockies and other U.S. basins.

CUSTOMERS, COMPETITION AND CONTRACTING

Customers

Our pipeline systems transport natural gas for a variety of customers including other natural gas pipelines, LDCs, industrial companies, electric power generation companies, natural gas producers, and natural gas marketers. Each type of customer has a different reason for using certain natural gas transportation services and routes. LDCs, industrial companies and electric power generation companies typically require a secure and reliable supply of natural gas over a sustained period of time to meet the needs of their customers. These types of shippers typically enter into long-term firm transportation contracts to ensure a ready supply of natural gas and sufficient transportation capacity to meet their obligations to their customers over the life of their contracts with their customers. Natural gas producers typically enter into firm transportation contracts to ensure that they will have sufficient capacity to deliver their product to market centers. Natural gas marketers typically use transportation services to capitalize on natural gas price volatility and therefore tend to contract for shorter terms to increase their flexibility.

Great Lakes The largest customer for Great Lakes' capacity is TransCanada, through its Canadian mainline pipeline system. This capacity is used by TransCanada customers to transport WCSB gas to Eastern Canadian and U.S. markets. TransCanada's ANR pipeline system also holds capacity on Great Lakes to integrate its Michigan storage locations with its Wisconsin pipeline segments. Great Lakes customers also include various LDCs, natural gas marketers and producers. Great Lakes' customer profile is becoming more heavily weighted towards natural gas marketers and less towards producers and end users, such as industrial customers and LDCs.

For the year ended December 31, 2009, contracts with TransCanada and its affiliates represented approximately 49 per cent of Great Lakes' revenue. Great Lakes did not have any other customers contributing more than 10 per cent of its 2009 revenues. TransCanada has elected to turn back contracts for 361 MDth/d of capacity as of October 31, 2010. This is discussed further under "Contracting".

Northern Border Northern Border's main customers are natural gas producers and marketers. Other customers include industrial facilities, LDCs and electric power generating companies.

For the year ended December 31, 2009, contracts with BP Canada Energy Marketing Corp. and Tenaska Marketing Ventures represented approximately 17 per cent and 11 per cent, respectively, of Northern Border's revenue. Northern Border did not have any other customers contributing more than 10 per cent of its 2009 revenues.

North Baja North Baja's main customers are electric power generating companies and natural gas marketers.

North Baja's revenues are dependent upon a relatively small group of customers. For the year ended December 31, 2009, the following shippers had contracts which contributed revenues in excess of 10 per cent of North Baja's overall revenues (including the period prior to the Partnership's July 1, 2009 acquisition of North Baja):

Sempra LNG Marketing Corp.	32%
Shell Energy North America	19%
Energia Azteca	15%
Gasoducto Rosarito	12%
Termoelectrical de Mexicali	11%

Tuscarora Tuscarora's main customers are a power generation company and an LDC, along with a variety of industrial, commercial, and other companies.

For the year ended December 31, 2009, contracts with Sierra Pacific Power Company and Southwest Gas Corporation contributed approximately 76 per cent and 11 per cent, respectively, of Tuscarora's revenue. Tuscarora did not have any other customers contributing more than 10 per cent of its 2009 revenues.

Competition

Competition among natural gas pipelines is based primarily on transportation rates and proximity to natural gas supply areas and markets. Our pipeline systems face competition at both the supply and market ends of their pipeline systems. At the supply end, other pipelines access the WCSB and provide alternative routes for shippers to access markets served by our systems or take gas to markets not served by our pipeline systems. Competition at the market end comes from WCSB natural gas which may be transported through alternative pipeline systems as well as from natural gas sourced from other U.S. supply basins, including shale gas, which can be transported by other pipelines into our pipeline systems' market areas. Our North Baja pipeline system is not connected to the WCSB and therefore is not sensitive to WCSB competitive factors.

Reductions in gas exiting the WCSB over recent years have resulted in excess pipeline capacity serving the WCSB. As a result, there has been an increase in competition for gas exiting the WCSB. We anticipate there will be excess natural gas pipeline capacity serving the WCSB for the foreseeable future and therefore competition for gas exiting the WCSB will continue. Commencing January 1, 2010, one of the main pipelines accessing the WCSB, the TransCanada Mainline pipeline system, increased its rates for firm transportation services by 40 per cent. This may improve the relative competitive position of the other pipelines accessing the WCSB, including our Great Lakes and Northern Border pipeline systems.

New natural gas supplies from unconventional sources, such as shale, and new pipeline projects in the U.S. moving additional natural gas supply from the Rockies basin and from the Barnett Shale have increased the supply competition in the markets served by our pipeline systems. This additional supply delivered to Midwest and Eastern markets is displacing traditional supply in the markets served by our pipeline systems.

Great Lakes Great Lakes' principal business comes from its position as a link in the chain of pipelines that facilitate the transportation of natural gas from WCSB to Midwest and Northeast U.S. markets and Eastern Canadian markets. Natural gas is transported by TransCanada from Western Canada to near Emerson, Manitoba, Canada. Great Lakes provides transportation from Emerson to the TransCanada system at St. Clair, Ontario. TransCanada transports the gas received at St. Clair to Dawn, Ontario, Canada and points further east. The primary competition for Great Lakes is the alternate route from Western Canada to Dawn on TransCanada's Mainline. Other routes from Western Canada to Ontario, Canada, are the Foothills Pipeline to Northern Border to Vector Pipeline route, or the Alliance Pipeline which also interconnects with the Vector Pipeline. In addition, gas can be delivered to the markets served by Great Lakes by competing pipelines that have access to alternate sources of supply from the Rockies, Mid-Continent and Gulf Coast.

Northern Border Northern Border's system competes for natural gas supply with other pipelines that transport WCSB natural gas to markets in the West, Midwest and East in North America. The pipeline systems that offer primary competition in these markets include Alliance Pipeline, Great Lakes, GTN, and other pipelines that interconnect with the TransCanada Mainline for WCSB supply. Northern Border also has competition in its market areas from other pipelines that have access to natural gas storage facilities, and alternate sources of supply from the Rockies, Mid-Continent, Permian Basin and Gulf Coast, as well as LNG. The pipeline systems that deliver natural gas from competing supply sources include Northern Natural Gas Company in Northern Border's Ventura, Iowa market area and ANR, Midwestern Gas Transmission Company and Natural Gas Pipeline of America in the Chicago market region.

Increased competition in the Chicago market can impact the Ventura market. In the face of this competition, Northern Border customers with firm service to the Chicago market may increase deliveries to the Ventura market, thereby reducing Northern Border's ability to capture additional transportation revenues to Ventura.

The combination of growing supply from the Rockies and shale developments reaching the Chicago market region through new and available pipeline capacity, and reductions in demand resulting from the current economic environment has negatively impacted Northern Border's ability to contract available capacity to Ventura and Harper. The impact of these competitive factors is expected to continue in 2010. Northern Border's contracting position is discussed further under "Contracting".

North Baja North Baja's southbound deliveries into Mexico will compete with LNG deliveries from the Energia Costa Azul terminal when supply is received at that terminal. Shippers retain contracts on North Baja to be able to provide service to several power plants in Baja California, Mexico at times when LNG sourced gas from the Costa Azul terminal is unavailable. As well, North Baja provides a critical path for LNG from the Energia Costa Azul terminal to reach markets in the southwestern United States, once cargos of LNG are received at this terminal.

Tuscarora Tuscarora's primary competition in the Northern Nevada natural gas transportation market is with Paiute Pipeline Company (Paiute), owned by Southwest Gas Co. Paiute interconnects with Northwest Pipeline Corp. at the Nevada-Idaho border and transports natural gas from British Columbia, Canada and from the Rockies to the Northern Nevada market.

Contracting

Transportation contracts mature at varying times and for varying amounts of throughput capacity. As existing contracts on our pipeline systems approach their expiration dates, efforts are made to extend and/or renew the contracts. The ability to extend and/or renew expiring contracts will depend upon competitive alternatives, the regulatory environment, and market and supply factors. The length of new or renegotiated contracts will be affected by current market price spreads, transportation rates, competitive conditions, levels of available pipeline capacity, and judgments concerning future market trends and volatility. Customer liquidity and capital constraints can also impact the length of contracts. If market conditions are not favorable at the time of renewal, transportation capacity may remain available until market conditions become more favorable. Subject to regulatory requirements, our pipeline systems attempt to recontract or remarket their capacity at the maximum rates allowed under their tariffs. However, a pipeline system may discount capacity under certain circumstances in order to maximize revenue.

Increased competition within the North American natural gas industry has resulted in a trend towards shorter term contracting as customers assess and choose the markets which optimize their netback prices.

Great Lakes For the year ended December 31, 2009, Great Lakes' average contracted capacity compared to average design capacity was 100 per cent. Great Lakes had long-term firm transportation contracts for 89 per cent of its average design capacity with a weighted average remaining contract life of 2.0 years, as at January 31, 2010. On November 1, 2010, the per cent of average design capacity contracted on a firm basis decreases to 68 per cent.

Great Lakes had approximately 990 MDth/d of long haul capacity expiring on October 31, 2010, of which 831 MDth/d, representing 36 per cent of Great Lakes' average design capacity, was contracted with TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts through October 31, 2011 for 470 MDth/d of capacity, or 20 per cent of average design capacity, some at a slightly discounted rate, and agreed that Great Lakes would provide other transportation services. TransCanada elected to turn back 361 MDth/d, or 16 per cent of average design capacity, as of October 31, 2010. Of the remaining long haul capacity expiring on October 31, 2010, 125 MDth/d was turned back.

In addition to the long haul capacity expiries, Great Lakes has an additional 110 MDth/d of short haul capacity under contract expiring on October 31, 2010. The cost and revenue study filed by Great Lakes with the FERC on February 4, 2010 reflects the increased risk of de-contracting on the Great Lakes system. Great Lakes is discounting transportation capacity as needed to optimize revenue. Refer to Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion.

Northern Border For the year ended December 31, 2009, Northern Border's average contracted capacity compared to design capacity was 68 per cent. Some of this capacity was sold at a discount to maximize overall revenue on the Port of Morgan, Montana to the Ventura and Harper, Iowa portions of the pipeline. As of January 31, 2010, Northern Border had long-term firm transportation contracts for 69 per cent of its design capacity in the first quarter of 2010, decreasing to 36 per cent beginning in the second quarter of 2010 following contract maturities. The weighted average remaining contract life at January 31, 2010 was 1.9 years. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue. Refer to Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion.

Shippers on the Bison Pipeline project, a project sponsored by TransCanada, have executed 10 year contracts for approximately 407 MMcf/d of capacity on the Northern Border system from Port of Morgan, Montana to Ventura, Iowa, commencing on the in-service date of the Bison Pipeline project. If the Bison Pipeline project is completed, this would increase Northern Border's average contracted capacity and weighted average contract life.

North Baja Due to North Baja's bi-directional nature, it has the ability to accept receipts at both ends of its system. North Baja's average contracted capacity for the year ended December 31, 2009 was 79 per cent of southbound capacity and 64 per cent of northbound capacity. As at January 31, 2010, North Baja had long-term firm transportation contracts for 79 per cent of its capacity for southbound receipts and 64 per cent of its capacity for northbound receipts, with a combined weighted average remaining life of the contracts of 16.7 years.

Tuscarora Tuscarora's average contracted capacity for the year ended December 31, 2009 was 99 per cent. Tuscarora had long-term firm transportation contracts for approximately 97 per cent of its design capacity with a weighted average remaining contract life of 10.6 years, as at January 31, 2010.

REGULATORY ENVIRONMENT

Government Regulation

Great Lakes, Northern Border, North Baja and Tuscarora are regulated under the Natural Gas Act of 1938, Natural Gas Policy Act of 1978, and Energy Policy Act of 2005, which give the FERC jurisdiction to regulate virtually all aspects of their businesses, including:

transportation of natural gas;

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.

Rate Proceeding, Great Lakes On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 (November 2009 Order) instituting an investigation pursuant to Section 5 of the Natural Gas Act (GL Rate Proceeding). The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable. On February 4, 2010, Great Lakes filed a cost and revenue study (GL Cost and Revenue Study) in response to the November 2009 Order. The GL Cost and Revenue Study supports Great Lakes' current rates, and shows that if Great Lakes filed to reset its rates, these rates should be above Great Lakes' current rates. The GL Cost and Revenue Study reflects the increased risk of de-contracting on the Great Lakes system which may result in decreases to overall long-term, daily and short-term firm transportation revenues, and interruptible transportation revenues, as compared to prior periods.

In the absence of a settlement, a hearing in the GL Rate Proceeding is scheduled for early August 2010 and an initial decision by the Administrative Law Judge is expected in November 2010. Should the FERC determine as a result of these proceedings, that Great Lakes' rates are not just and reasonable, the FERC could order Great Lakes to reduce its rates prospectively.

Rate Case, Northern Border In November 2006, the FERC approved the settlement with Northern Border's customers of its 2005 rate case effective January 1, 2007. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. The settlement also provided for seasonal rates for short-term transportation services. Pursuant to the terms of the settlement, there was a moratorium on the parties to the settlement of raising any proceeding regarding Northern Border's currently effective rates until January 1, 2010 and Northern Border must file a rate case on or before December 31, 2012.

Cost and Revenue Study, Tuscarora As a result of an obligation to file a cost and revenue study with the FERC, the Public Utilities Commission of Nevada and Sierra Pacific Power Company agreed to a settlement with Tuscarora, which was approved by the FERC in July 2006. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (Dth/d) beginning June 1, 2006 and included a moratorium on all rate actions before the FERC by any party to the settlement until May 31, 2010. The settlement includes a moratorium by the settlement parties on rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate.

Cost and Revenue Study, North Baja North Baja's jurisdictional rates were established as part of its original certificate authorization in January 2002. North Baja subsequently filed a cost and revenue study (as required by its certificate authorization) in August 2004, which was accepted by the FERC in December 2004 without change to North Baja's approved rates. North Baja continues to operate under the rates approved in 2004 and has no requirement to file a new rate proceeding.

The FERC initiates regulatory changes through orders intended to create a more competitive environment in the natural gas marketplace. Among the most important of these orders on our pipelines are:

Income Tax Allowance In December 2007, the FERC issued an order which upheld and clarified its methodology for determining a partnership's income tax allowance in a rate case. In the future, partnerships will be required to prove (1) that their partners have an actual or potential income tax liability, which is determined by the partner's obligation to file a return that recognizes either a taxable gain or loss; (2) their partners' marginal Federal income tax rates, if higher than the commission's default rates of 28 per cent for individuals and 34 per cent for corporations; and (3) the partners' marginal state income tax rates. If the FERC were to disallow a portion of the income tax allowance for one of our pipeline systems in a rate case, it may cause its recourse rate to be set at a level that is lower than the level otherwise in effect.

Composition of Proxy Groups for Rates of Return Determinations In July 2007, the FERC issued a policy statement proposing to update its standards regarding the composition of proxy groups for determining the appropriate returns on equity (ROE) for natural gas and oil pipelines, which is used by pipelines to establish rates for services. In April 2008, the FERC issued a policy statement (2008 Policy Statement) that allows master limited partnerships (MLPs) to be included in a proxy group used to determine a pipeline's ROE. The 2008 Policy Statement provides that there should be no cap on the level of distributions included in the current Discounted Cash Flow (DCF) methodology for MLPs, but there should be an adjustment to the long-term growth rate used to calculate DCF for an MLP (halving the long-term GDP factor which has a one-third weighting in the total growth rate computation in the DCF methodology).

The impact of applying this new policy to each of our pipeline systems will not be known until each pipeline system files a rate case.

Energy Affiliates In October 2008, the FERC issued Order No. 717, Standards of Conduct for Transmission Providers, which amended the regulations adopted on an interim basis in Order No. 690 to refocus the rules on the areas where there is the greatest potential for abuse; the day-to-day transmission transactions and operations that may involve marketing affiliates. This order identifies those affiliate relationships where there is the greatest potential and risk for undue discrimination and preference between a natural gas pipeline company and their marketing affiliates. The rule subjects the natural gas pipeline company to certain restrictions to function independently and not act as a conduit of transmission information to a marketing affiliate.

Promotion of a More Efficient Capacity Release Market Docket No. RM08-1 In June 2008, the FERC issued a final rule to modify capacity release regulations (Capacity Release Final Rule). The Capacity Release Final Rule, in addition to other items, allows market-based pricing for short-term capacity releases by shippers through a permanent lifting of the maximum rate cap on short-term capacity releases (of one year or less terms). The Capacity Release Final Rule was effective July 30, 2008.

While implementation of the Capacity Release Final Rule is not expected to have a significant impact on our pipeline systems, the Interstate Natural Gas Association of America (INGAA), of which our pipeline systems are members, filed in July 2008 a request for rehearing of the Capacity Release Final Rule, contending that as the FERC removed the rate cap for short-term released capacity, it should also remove the rate cap for short-term pipeline capacity. INGAA notes that short-term released capacity and short-term pipeline capacity compete in the same market, and argues that removing the rate cap for short-term released capacity and maintaining the cap for short-term pipeline capacity results in a bifurcated and distorted short-term capacity market. In November 2008, the FERC issued Order No. 712-A addressing requests for clarification and rehearing. In that order, the FERC denied INGAA's request for rehearing and continued to maintain that the maximum rate ceilings for pipeline short-term transactions is necessary to protect against the potential exercise of market power. On January 15, 2009, INGAA filed an appeal of FERC's order which is pending before the U.S. Court of Appeals D.C. Circuit.

Compliance with Statutes, Regulations, and Orders Docket No. PL09-1-000 In October 2008, the FERC issued a "Policy Statement on Compliance" to provide additional guidance to the public on compliance with governing statutes, regulations and orders. The policy statement sets forth the following factors which will be considered when deciding to reduce or eliminate civil penalties for violations: 1) the role of senior management in fostering compliance; 2) effective preventive measures to ensure compliance; 3) prompt detection, cessation, and reporting of violations; and 4) remediation efforts.

Environmental Matters

All of our pipeline systems' operations 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. These laws and regulations also can restrict or impact business activities in many ways, such as restricting the way wastes are handled or disposed of; requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators; and enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. 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 the issuance of orders enjoining future operations.

Waste Management The operations of our pipeline systems generate hazardous and non-hazardous solid wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and non-hazardous solid wastes. For instance, RCRA prohibits the disposal of certain hazardous wastes on land without prior treatment, and requires generators of wastes subject to land disposal restrictions to provide notification of pre-treatment requirements to disposal facilities that are in receipt of these wastes. Generators of hazardous wastes also must comply with certain standards for the accumulation and storage of hazardous wastes, as well as with recordkeeping and reporting requirements applicable to hazardous waste storage and disposal activities.

Site Remediation The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as "Superfund", and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons considered to be responsible for the release of hazardous substances into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies.

Our pipeline systems currently own or lease properties that for many years have been used for the transportation and compression of natural gas. These properties and the substances released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, our pipeline systems could be required to remove any previously disposed wastes, including waste disposed of by prior owners or operators; remediate contaminated property, including groundwater contamination, whether from prior owners or operators or other historic activities or spills; or perform remedial closure operations to prevent future contamination.

Air Emissions The Clean Air Act (CAA) and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase of existing air emissions; application for, and strict compliance with, air permits containing various emissions and operational limitations; or the utilization of specific emission control technologies to limit emissions.

By letter dated December 28, 2009, the U.S. Environmental Protection Agency (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. Great Lakes is in the process of preparing its response and providing the information, all of which is due by May 29, 2010. The results of this information request is not determinable at this time.

On February 2, 2009, Northern Border received a Notice of Violation (NOV) from the EPA alleging that Northern Border was in violation of certain regulations pursuant to the CAA regarding a compressor station on its system. Northern Border disputes the NOV. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty, but does not expect such amounts to be material to its financial condition.

Climate Change The U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA has released a finding that said that greenhouse gases are air pollutants under the CAA. The EPA has drafted regulations to reduce greenhouse gas emissions. It is uncertain whether the EPA will proceed with adopting final rules or whether the regulation of greenhouse gases will be addressed in federal legislation.

Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide, in areas in which our pipeline systems conduct business, could result in changes to the consumption and demand for natural gas. This could have adverse effects on our business, financial position, results of operations and prospects. Such changes could increase the costs of our pipeline systems' operations, including costs to operate and maintain facilities, install new emission controls, acquire allowances to authorize our pipeline systems' greenhouse gas emissions, pay any new taxes related to greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or to our customers, such recovery of costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC, and the provisions of any final legislation.

Water Discharges The Clean Water Act (CWA) and analogous state laws impose strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the U.S. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Federal and state regulatory agencies may impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Activities on Federal Lands Natural gas transportation activities are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses 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.

Safety Matters

Pipeline Safety The operations of our pipeline systems are also regulated by the U.S. Department of Transportation with respect to their design, installation, testing, construction, operation, replacement and management. The Transportation Security Administration oversees the regulation related to the security of our pipeline systems. The Pipeline Safety Improvement Act of 2002 requires pipeline companies to perform integrity assessments on pipeline segments that exist in densely populated areas or near specifically identified sites that are designated as high consequence areas. Pipeline companies are required to perform the integrity assessments within ten years of the date of enactment and perform subsequent integrity assessments on a seven-year cycle. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained.

In general, there are proposed and existing industry regulations related to the operation of our pipeline systems with respect to safety and environmental standards that could increase our costs in the future. Such increases in costs cannot be accurately estimated at this time.

Title to Properties

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 sites for compressor stations, meter stations, pipeline field offices, microwave towers and a corporate office. Our pipeline systems also derive interests from leases, easements, rights-of-way, permits and licenses from landowners or governmental authorities permitting land use for construction and operation of their pipelines.

Great Lakes Approximately 74 miles of Great Lakes' pipeline system are 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. In 1968, Great Lakes obtained right-of-way across allotted lands located within each of the reservation's boundaries. All of the allotted lands are subject to a 50 year easement granted by the Bureau of Indian Affairs (BIA) for and on behalf of the individual Indian owners or the reservations. These tracts are subject to right-of-way permits issued by the BIA that expire in 2018. Also, the Great Lakes pipeline crosses approximately 1,000 feet in two tracts in Lower Michigan, which are located within the Chippewa Indian Reservation, under perpetual easements.

Northern Border Approximately 90 miles of Northern Border's pipeline system are located within the boundaries of the Fort Peck Indian Reservation in Montana. In 1980, Northern Border entered into 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. This pipeline right-of-way lease granted Northern Border the right to construct and operate its pipeline on certain tribal lands. The pipeline right-of-way lease expires in 2011, with an option to renew the pipeline right-of-way lease through 2061. In conjunction with obtaining a right-of-way across tribal lands located within the exterior boundaries of the Fort Peck Indian Reservation, Northern Border also obtained right-of-way 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 Indian owners or obtained through condemnation. Several tracts are subject to a right-of-way grant that expires in 2015.

Insurance

The Partnership's operations and activities are insured under TransCanada insurance programs, including property insurance, liability, automobile liability and workers compensation, in amounts which management believes are reasonable and appropriate.

Employees

The Partnership does not have any employees. In addition, none of our pipeline systems directly employ any of the persons responsible for managing or operating the pipeline systems or for providing them with services related to their day-to-day business affairs. Subsidiaries of TransCanada are the operators of our pipeline systems, in addition to providing services to the Partnership.

AVAILABLE INFORMATION

Our website is www.tcpipelineslp.com. We make available free of charge, on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing or furnishing such reports with the Securities and Exchange Commission (SEC). Information contained on our web site is not part of this report.

Item 1A. Risk Factors

Cautionary Statement Regarding Forward-Looking Information

A number of statements made by TC PipeLines, LP (the Partnership) in this Form 10-K filing are forward-looking and relate to, among other things, anticipated financial performance, regulatory actions, business prospects, strategies, market forces and commitments. Much of this information appears in "Management's Discussion and Analysis of Financial Condition and Results of Operations" found herein. All forward-looking statements are based on the Partnership's current beliefs as well as assumptions made by and information currently available to the Partnership. These statements reflect the Partnership's current views with respect to future events. The Partnership assumes no obligation to update any such forward looking statements to reflect events or circumstances occurring after the date hereof. Words such as "anticipate," "believe," "estimate," "expect," "plan," "intend," "forecast," and similar expressions, identify forward-looking statements. By its nature, such forward-looking information is subject to various risks and uncertainties, including the risk factors discussed below, which could cause the Partnership's actual results and experience to differ materially from the anticipated results or other expectations expressed in this Form 10-K. Readers are cautioned not to place undue reliance on this forward-looking information, which is as of the date of this Form 10-K.

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. All of the information included in this report and any subsequent reports we may file with the SEC or make available to the public should be carefully considered and evaluated before investing in any securities issued by us.

Each of the risks and uncertainties described below could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations and cash flows, including our ability to make distributions to our unitholders.

The risks referred to herein disclose risks inherent in the Partnership and our pipeline systems.

Risks Inherent in Our Business

The long-term financial conditions of our pipeline systems, except North Baja, are dependent on the continued availability of gas exiting the WCSB and the market demand for these volumes. Competition from pipelines that deliver natural gas from other supply sources to our pipeline systems' market areas could cause our pipeline systems to discount their rates or otherwise experience a reduction in their revenues.

The development of additional natural gas reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to pipelines that interconnect with our pipeline systems. High exploration and production costs, low prices for natural gas, regulatory limitations such as royalty frameworks, and competition for capital from other North American gas production basins that have lower exploration costs has adversely affected the development of additional reserves in Western Canada and the production in the WCSB in 2009 and may continue to do so in 2010.

Gas exiting the WCSB depends in part on the internal demand for Western Canadian natural gas. Western Canadian demand may increase as a result of increased demand for natural gas fired electricity generation and other industrial requirements, including the development of oil sands projects, which may require substantial amounts of natural gas. This higher internal demand may reduce the amount of gas available for downstream markets. In the longer term, a portion of the Alberta Hub gas supply may come from the development of recently discovered natural gas shale resources such as Montney and Horn River in Western Canada and from proposed gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada. Cancellation, changes in route, and delays in the construction of such pipelines or such projects could adversely affect gas exiting the WCSB in the long term.

If the availability of Alberta Hub natural gas was to decline, existing shippers on our pipeline systems, except North Baja, may be unlikely to extend their contracts and our pipeline systems may be unable to find replacement shippers for lost capacity. Furthermore, additional natural gas reserves may not be developed in commercial quantities and in sufficient amounts to fill the capacities of each of our pipeline systems.

Customers may not extend their contracts or contract for transportation if the cost of delivered natural gas from other producing regions into the markets served by our pipeline systems is lower than the cost of natural gas delivered by our pipeline systems.

An increase in competition in the key markets served by our pipeline systems could arise from new ventures or expanded operations from existing competitors. The combination of growing supply from the Rockies and shale developments reaching the Chicago market region through both new and available pipeline capacity and demand destruction from the economic environment has the potential to maintain competitive pressures on WCSB supply into the Midwest. Northern Border is fully contracted on its Eastern system that deliveries gas to Chicago; however, any reduction in flows to this market will impact the supply and demand fundamentals at the Ventura market. Northern Border has experienced reduced demand for its transportation services due to these competitive factors with only 68 per cent of its capacity contracted in 2009, down from 90 per cent in 2008, and certain of Great Lakes capacity has not been renewed beyond 2010 with 486 thousand dekatherms per day (MDth/d) of long haul capacity and approximately 110 MDth/d of short haul capacity under contracts expiring on October 31, 2010.

Our financial performance depends to a large extent on the capacity contracted on our pipeline systems. Decreases in the volumes transported by our pipeline systems, whether caused by supply or demand factors in the markets these pipeline systems serve, competition or otherwise, can directly and adversely affect our business, financial position, results of operations, and ability to make distributions.

Our pipeline systems may not be able to maintain existing customers or acquire new customers when the current shipper contracts expire or customers may recontract for shorter periods or at less than maximum rates.

The ability to extend and replace contracts on terms comparable to prior contracts or on any terms at all could be adversely affected by factors, including:

- the available supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply in the U.S.;
- competition from other pipelines, including through their transportation rates or through their access to upstream supplies, as well as the proposed construction by other companies of additional pipeline capacity;
- the price of, and demand for, natural gas in markets served by our pipeline systems;
- the liquidity and willingness of shippers to contract for transportation services; and
- regulatory actions.

Ongoing changes in these factors and customers' ability to adjust to changing market conditions may cause Great Lakes and Northern Border to sell a significant portion of available capacity on a short-term basis. The weighted average lives of Great Lakes' and Northern Border's contracts have generally declined over time. As at January 31, 2010, the weighted average remaining lives of Great Lakes' and Northern Border's contracts were 2.0 years and 1.9 years, respectively. Some of Great Lakes capacity has not been renewed beyond 2010 with 486 MDth/d of long haul capacity and approximately 110 MDth/d of short haul capacity under contracts expiring on October 31, 2010.

Additionally, when the forward natural gas basis differentials do not support maximum rates, Great Lakes and Northern Border sell portions of their capacity at discounted rates. Great Lakes' and Northern Border's inability to renew existing contracts at maximum rates, or at all, or to enter into new long-term shipper contracts for upcoming excess capacity will have an adverse impact on their revenues and, as a result, cash distributions made to us.

Our pipeline systems are subject to regulation by agencies, including the FERC, which could have an adverse impact on our ability to establish transportation rates that would allow recovery of the full cost of operating our pipeline systems, including a reasonable return, and our ability to make distributions.

Under the Natural Gas Act (NGA), interstate transportation rates must be just, reasonable and not unduly discriminatory. Our pipeline systems are subject to extensive regulation by the FERC, the U.S. Department of Transportation, and other federal, state and local regulatory agencies. Regulatory actions taken by these agencies have the potential to adversely affect our pipeline systems' profitability. Federal regulation extends to such matters as:

- rates and charges;
- operating terms and conditions of service including creditworthiness requirements;
- types of services our pipeline systems may offer to their customers;
- construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- income tax allowance policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- standards of conduct business relations with certain affiliates; and
- integrity and safety of our pipeline systems and related operations.

Given the extent of regulation by the FERC and potential changes to regulations, we cannot predict:

- the federal regulations under which our pipeline systems will operate in the future;
- the effect that regulation will have on financial position, results of operations and cash flows of our pipeline systems and ourselves; or
- whether our cash flow will be adequate to make distributions to unitholders.

Tuscarora is currently operating under a rate settlement which precludes a party to the rate settlement from bringing any rate actions prior to May 31, 2010. Northern Border is required to file a new rate proceeding on or before December 31, 2012.

The FERC has instituted an investigation (GL Rate Proceeding), pursuant to Section 5 of the NGA, against Great Lakes alleging that Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable. Great Lakes filed a cost and revenue study in the GL Rate Proceeding that shows that restated rates on Great Lakes' system should be above Great Lakes' current rates. The cost and revenue study reflects the increased risk of de-contracting on the Great Lakes system which may result in decreases to overall long-term, daily and short-term firm transportation revenues, and interruptible transportation revenues, as compared to prior periods.

In the absence of a settlement, a hearing in the GL Rate Proceeding is scheduled for early August 2010 and an initial decision by the Administrative Law Judge is expected in November 2010. Should the FERC determine as a result of these proceedings, that Great Lakes' rates are not just and reasonable; the FERC could order Great Lakes to reduce its rates prospectively, which could adversely affect the cash distributions made to us.

Action by the FERC on currently pending regulatory matters as well as matters arising in the future could adversely affect our pipeline systems' abilities to establish or charge rates that would cover future increase in their costs, such as additional costs related to environmental matters including any climate change regulation, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot assure unitholders that our pipeline systems will be able to recover all of their costs through existing or future rates.

Should our pipeline systems fail to comply with all applicable FERC administered statutes, rules, regulations and orders, our pipeline systems could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

Finally, we cannot give any assurance regarding the future regulations under which our pipeline systems will operate their natural gas transportation businesses or the effect such regulations could ultimately have on our financial condition, results of operations and cash flows.

If our pipeline systems do not maintain their respective rate bases, the amount of revenue attributable to the return on the rate base they collect from their shippers will decrease over time.

Our pipeline systems are generally allowed to collect from their customers a return on their assets or "rate base" as reflected in their financial records as well as recover that rate base through depreciation. In the absence of additions to the rate base through capital expenditures, the amount they collect from customers, as a result of a rate case, decreases as the rate base declines due to, among other things, depreciation and amortization.

Cash distributions are dependent primarily on our cash flow, financial reserves and working capital borrowings.

Cash distributions are not dependent solely on our profitability, which is affected by non-cash items. 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 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;
- the amount of cash distributed to us by the entities in which we own a non-controlling interest;
- 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 are dependent on our pipeline systems to generate sufficient cash to enable us to pay distributions.

The amount of cash we have on a quarterly basis to distribute to our common unitholders depends upon numerous factors, most of which are beyond our control and the control of our general partner, including:

- the rates charged and the volumes under contract for the transportation services of our pipeline systems;

the quantities of natural gas available for transport and the demand for natural gas;

legislative or regulatory action affecting demand for and supply of natural gas, and the rates our pipeline systems are allowed to charge in relation to their operating costs;

the level of our pipeline systems' operating costs; and

the creditworthiness of our pipeline systems' shippers.

The recent global economic and financial market crisis has had and may continue to have a negative effect on our business.

The recent global economic and financial market crisis caused, among other things, a general tightening in the credit markets, lower levels of liquidity, increases in the rates of default and bankruptcy, lower consumer and business spending, lower consumer net worth, and reduced energy demand. Although, general economic conditions are improving, recovery for certain sectors will be slower. As a result of the economic weakness, there has been less demand for natural gas by residential, industrial and other users, which has had a negative effect on the business of our pipeline systems and our results of operations, financial condition and liquidity. Many natural gas producers, natural gas marketing companies, and end users have been negatively affected by the current economic conditions, as evidenced by reduced drilling and natural gas development in the WCSB, which is a critical natural gas supply source for our pipeline systems, except North Baja. Current or potential shippers may be unable to fund contracts or meet the creditworthiness requirements of our pipeline systems or they may reduce the amount or length of their transportation commitments on our pipeline systems, all of which could impact demand for transportation services on our pipeline systems, and may cause reduced revenue and increased customer payment delays or defaults. We are also limited in our ability to reduce costs to offset the results of a prolonged or severe economic downturn given the high percentage of fixed costs associated with our operations.

Although there are indications of some recovery in the credit and financial markets, there can be no assurance that market conditions will continue to improve in the near future or that any improvements will be sustained or that our results will not be materially and adversely affected. Such conditions make it difficult to forecast operating results, make business decisions and identify and address material business risks. The foregoing conditions may also impact the valuation of certain long-lived or intangible assets, including goodwill, that are subject to impairment testing, potentially resulting in impairment charges which may be material to our financial condition or results of operations.

If we do not identify opportunities for accretive growth through organic growth projects or acquisitions, or our pipeline systems do not successfully complete expansion projects or make and integrate acquisitions that are accretive, our future growth may be limited.

A principal focus of our strategy is to continue to grow the cash distributions on our 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 pipelines systems to complete expansion projects and make and integrate acquisitions that result in an increase in cash per unit generated from operations.

If any significant shipper fails to perform its contractual obligations, our pipeline systems' respective cash flows and financial condition could be adversely impacted.

At any time, each of our pipeline systems may have customers that account for more than ten per cent of their revenue. The loss of all or even a portion of the revenues associated with these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on the financial condition, results of operations and cash flows of our pipeline systems, unless they were able to contract for comparable volumes from other customers at favorable rates.

Sierra Pacific Power Company and Southwest Gas Corporation are Tuscarora's largest shippers, with firm contracts for approximately 76 per cent and 11 per cent, respectively, of Tuscarora's revenue. NV Energy Inc. (formerly known as Sierra Pacific Resources) and its subsidiary, Sierra Pacific Power Company, have non-investment grade credit ratings.

Our pipeline systems' pipeline integrity testing programs and any necessary pipeline repairs, or preventative or remedial measures may impose significant costs and liabilities.

The U.S. Department of Transportation has 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 what the regulations refer to as "high consequence areas", where a leak or rupture could do the most harm. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the total costs of compliance with this rule because those costs will depend on the extent of the pipeline testing and any subsequent repairs found to be necessary. Our pipeline systems completed the required 50 per cent inspection of their respective pipelines highest priority highest consequence segments of lines in 2007. Inspection of the remaining 50 per cent of high consequence areas as mandated by regulation is expected to be completed, as required, by 2012. After that point, the inspection of high consequence areas is required to reoccur every seven years. Once 100 per cent of our pipeline systems' high consequence areas have been inspected, we will have a better understanding of the total ongoing costs. Our pipeline systems will continue their pipeline integrity testing programs to assess and maintain the integrity of the pipelines. The results of this work 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 these regulations could subject our pipeline systems to penalties and fines. If these costs were significantly higher than estimated, our cash available for distribution may be correspondingly reduced.

Our pipeline systems' operations are regulated by federal, state and local agencies responsible for environmental protection and operational safety, and costs of environmental compliance and the costs of environmental liabilities could exceed our estimates.

Risks of substantial costs and liabilities are inherent in pipeline operations and each of our pipeline systems may incur substantial costs and liabilities in the future as a result of stricter environmental and safety laws, regulations, and enforcement policies and claims for personal or property damages resulting from our pipeline systems' operations. Moreover, new, stricter 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 that may become necessary, and these costs could be material. For instance, we may be required to obtain and maintain permits and approvals issued by various federal, state and local governmental authorities; limit or prevent releases of materials from our operations in accordance with these permits and approvals; and install pollution control equipment. Also, under certain environmental laws and regulations, we may be exposed to substantial liabilities for any pollution or contamination that may result from our operations.

With respect to climate change related policy, in December 2009 the Environmental Protection Agency (EPA) signed two findings regarding six greenhouse gas (GHG) emissions in response to the 2007 US Supreme Court decision that these emissions are covered under the Clean Air Act (CAA). The Endangerment Finding and the Cause or Contribute Finding both allow the EPA to implement regulations that restrict the releases of specified GHG emissions. On September 30, 2009, the EPA released the proposed Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. The rule proposes new thresholds for GHG emissions that define when Clean Air Act permits under the New Source Review and title V operating permits programs would be required for new or existing industrial facilities. Under the Title V operating permits program, EPA is proposing a major source emissions applicability threshold of 25,000 tons per year of carbon dioxide CO2e for existing industrial facilities. Facilities with GHG emissions below this threshold would not be affected. New or modified facilities with GHG emissions that trigger the Prevention of Significant Deterioration permitting requirements would need to apply for revisions to their operating permits to incorporate the best available control technologies and energy efficiency measures to minimize GHG emissions. The EPA's Mandatory Reporting of Greenhouse Gases; Final Rule became effective December 29, 2009. The program requires monitoring and reporting of GHG emissions from specified sources emitting over 25,000 metric tonnes per year.

The U.S. Congress is also actively considering federal legislation to reduce domestic greenhouse gas emissions. The House of Representatives passed the American Clean Energy and Security Act H.R. 2454 in June 2009. The HR.2454 legislation along with a series of other climate bills, including the Carbon Limits and Energy for America's

Renewal Act, are now under consideration by the Senate. These proposals could be rejected by the Senate, or could be significantly amended before being approved. At a regional level, several states have already taken legal measures to reduce emissions of greenhouse gases. At this time it is unknown what the future environmental compliance costs relating to greenhouse gas activities will be at federal and state levels. Various federal and state legislative proposals have been made over the last several years and it is possible that legislation will be enacted in the future that could negatively impact the operations of our pipeline systems, result in increased costs and reduce our income if our pipeline systems cannot recover any increased costs in their rates.

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

As at December 31, 2009, Great Lakes, Northern Border and Tuscarora had $411.0 million, $565.0 million and $57.3 million of debt outstanding, respectively. Of the debt outstanding, Great Lakes, Northern Border and Tuscarora have $19.0 million, $nil and $53.4 million of debt maturing in 2010, respectively. Their respective levels of debt could have important consequences to Great Lakes, Northern Border and Tuscarora, 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;

- they will need a portion of their cash flow to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to us, which will reduce our ability to make distributions to our unitholders;

- their debt level may make them more vulnerable to competitive pressures or a downturn in our 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 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. Under Tuscarora's debt instruments, Tuscarora has granted a security interest in certain of its transportation contracts, which is available to noteholders upon an event of default. 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.

Capital and credit market conditions may adversely affect the Partnership's and/or our pipeline systems' access to capital and cost of capital.

Access to capital markets is important to the Partnership to enable it to execute its business strategies, which include seeking opportunities to undertake accretive acquisitions and organic growth projects, and maximize the value of our existing portfolio of pipeline systems. Access to capital markets is also important to our pipeline systems' ability to meet liquidity and capital resource requirements. Additionally, market conditions may impact the ability of our pipeline systems to access capital markets for debt under reasonable terms.

Beginning in September 2008, the general economic and capital market conditions in the United States and other parts of the world deteriorated significantly and adversely affected access to capital and increased the cost of capital. Although capital market conditions improved in the second half of 2009, if conditions in the U.S. capital markets do not continue to improve or worsen, the Partnership's and our pipeline systems' future cost of debt and equity capital, and future access to capital markets could be adversely affected.

We do not own a controlling interest in Great Lakes or Northern Border and we may be unable to cause certain actions to take place unless the other partner agrees. As a result, we will be unable to control the amount of cash we will receive from those operations and we could be required to contribute significant cash to fund our share of their operations. If we fail to make these contributions our ownership interest would be diluted.

The major policies of Great Lakes and Northern Border are established by each of their Management Committees.

Great Lakes' Management Committee consists of four appointed members, two of whom are designated by us and two of whom are designated by TransCanada. All decisions by the Management Committee require unanimous consent. An Executive Committee consists of two appointed members: one Partnership Committee Member and one TransCanada Committee Member, who also serves as the president of Great Lakes. The Executive Committee has all of the powers of the Management Committee in the management of Great Lakes' business. Because of these provisions, without the concurrence of TransCanada, we may be unable to cause Great Lakes to take or not to take certain actions, even though those actions may be in the best interest of us or Great Lakes.

Northern Border's Management Committee consists of four members, two of whom are designated by us and two of whom are designated by an affiliate of ONEOK Partners. The Management Committee requires the affirmative vote of a majority of the partners' ownership interests to act on most activities. Certain activities require the unanimous consent of the committee, such as the filing of the application for regulatory authority to construct and operate new facilities and any changes to the cash distribution policy. Because of these provisions, without the concurrence of ONEOK, we may be unable to cause Northern Border to take or not to take certain actions, even though those actions may be in the best interest of us or Northern Border.

Great Lakes and Northern Border may require us to make additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. Additionally, in the event we elect not to, or are unable to, make a required capital contribution to Great Lakes or Northern Border; our ownership interest would be diluted.

Our pipeline systems' operations are subject to operational hazards and unforeseen interruptions, which could adversely affect their businesses and for which they may not be adequately insured.

Our pipeline systems' operations are subject to all of the risks and hazards typically associated with the operation of natural gas transportation pipeline systems. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes, and the performance of pipeline facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, the collision of equipment with our pipeline systems' pipeline facilities (which may occur if a third party were to perform excavation or construction work near these facilities), and catastrophic events such as explosions, fires, earthquakes, floods or other similar events beyond our pipeline systems' control. It is also possible that our pipeline systems' infrastructure facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred, and interruptions to the operation of our pipeline systems' facilities, for short or extended durations, caused by such an event, could reduce revenues generated by our pipeline systems and increase expenses, thereby impairing their ability to meet their obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost. Should one of our pipeline systems experience such an event, it may have an adverse impact on our results of operations and cash flow.

Our pipeline systems do not own all of the land on which their pipelines and facilities are located, which could disrupt 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 obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties, governmental agencies and Indian reservations for a specific period of time. Their loss of these rights, through their inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on their financial condition, results of operations and cash flows.

If we were to lose TransCanada's management expertise, we would not have sufficient stand-alone resources to operate.

TransCanada, through wholly-owned subsidiaries, is the operator of all our pipeline systems. We do not presently have sufficient stand-alone management resources to operate without services provided by TransCanada. Additionally, should we lose the services of TransCanada, we may not be able to replace those services for the same cost and our costs could increase. Further, we would not be able to evaluate potential growth opportunities and successfully complete acquisitions without TransCanada's resources.

Our pipeline systems may undertake or be dependent upon expansion and build projects which involve significant risks that could adversely affect our business.

Our pipeline systems have expansion and new build projects planned or underway. Additionally, expansion and new build projects, such as TransCanada's Bison Pipeline Project that would potentially deliver gas to Northern Border, are subject to a variety of factors outside their control. Factors such as weather, natural disasters, delays in obtaining key materials and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors may result in increased costs or delays in construction. Cost overruns or delays in completing a project could result in reduced transportation rates and liquidated damages to customers, as well as lost revenue opportunities. In addition, we cannot be certain that, if completed, these projects will perform in accordance with our expectations. Each of these risks could have a material adverse effect on our results of operations and cash flows.

Risks Inherent in an Investment in the Partnership

The Partnership's indebtedness may limit its ability to borrow additional funds, make distributions or capitalize on business opportunities. The conditions of the U.S. and international credit markets may adversely affect our ability to obtain credit or draw on our current credit facility.

As of December 31, 2009, the Partnership had $541.3 million of debt outstanding, including the revolving credit and term loan agreement (Senior Credit Facility) and Senior Notes. This substantial level of debt could have important consequences to the Partnership including the following:

- our ability to obtain additional financing, if necessary, for working capital, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- we will need a portion of our cash flow to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

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.

If the financial institutions that have extended credit commitments to us and our pipeline systems are adversely affected by the conditions of the U.S. and international capital markets, they may become unable to fund borrowings under their credit commitments, which could have a material and adverse impact on our financial condition and our ability to borrow additional funds, if needed.

In addition, our credit facilities contain restrictive covenants that may prevent us from engaging in certain transactions that are deemed beneficial. These agreements require us to comply with various affirmative and negative covenants and maintaining certain financial ratios. There are restrictions and covenants with respect to:

- entering into mergers, consolidations and sales of assets;
- granting liens;
- material amendments to the Partnership's partnership agreement;

incurring additional debt; and

distributions to unitholders.

Any future debt may contain similar restrictions.

Increases in 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, 2009, the partnership had $484.0 million outstanding under the Senior Credit Facility (2008 $475.0 million), all of which is initially exposed 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 decrease our exposure to variable interest rates. At December 31, 2009, the variable interest rate exposure related to $375.0 million of the $484.0 million outstanding debt under the Senior Credit Facility was mitigated by fixed interest rate swap arrangements.

An increase in interest rates may also cause a corresponding decline in demand for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us 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 unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to recapitalize by issuing more equity.

Unitholders have limited voting rights and do not control our general partner.

The general partner is our manager and operator. Unlike the holders of common stock in a corporation, holders of common units have only limited voting rights on matters affecting our business. Unitholders have no right to elect our general partner on an annual or other continuing basis. Our general partner may not be removed except by the vote of the holders of at least $66^2/_3$ per cent of the outstanding units and upon the election of a successor general partner by the vote of the holders of a majority of the outstanding common units. These required votes would include the votes of units owned by our general partner and its affiliates. The ownership of an aggregate of 37.0 per cent of the outstanding 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 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.

These provisions may diminish the price at which the common units will trade under some circumstances. The partnership agreement also 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 per cent or more of any class of units then outstanding, that person or group will lose voting rights with respect to all of its 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' interest. In addition, issuance of additional common units may increase the risk that we will be unable to pay the full minimum quarterly distribution on all common units.

Our general partner can cause us to issue additional common units, without the approval of unitholders, in the following circumstances:

- under employee benefit plans, if any;
- upon conversion of the general partner interests and incentive distribution rights into common units as a result of the withdrawal of our general partner; or
- in connection with acquisitions or capital improvements that are accretive to our cash flow on a per unit basis.

In addition, we may issue an unlimited number of limited partner interests of any type without the approval of the unitholders. Based on the circumstances of each case, the issuance of additional common units or securities ranking senior to or on a 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 and dilute the interests of unitholders in distributions by the Partnership. Our partnership agreement does not give the unitholders the right to approve the issuance by us of equity securities ranking junior to the common units at any time.

Any increase in the number of outstanding common units will increase the percentage of the aggregate minimum quarterly distribution payable to the common unitholders, which will in turn have the effect of increasing the risk that we will be unable to pay the minimum quarterly distribution in full on all the common units.

Unitholders may not have limited liability in some circumstances.

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. If it were to be 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,

then unitholders could be held liable in some circumstances for the Partnership's obligations to the same extent as a general partner. In addition, under some circumstances 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 our general partner and its affiliates, who currently own an aggregate of approximately 37.0 per cent of our common units, come to own 80 per cent 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.

Without the consent of each unitholder, Great Lakes, Northern Border, North Baja or Tuscarora might be converted into a corporation, which would result in Great Lakes, Northern Border, North Baja or Tuscarora, as the case may be, being subject to corporate income taxes.

If it becomes unlawful to conduct the business of Great Lakes, Northern Border or Tuscarora as a partnership and some other conditions are satisfied, the business and assets of Great Lakes, Northern Border or Tuscarora, as the case may be, will automatically be transferred to a corporation without the vote or consent of unitholders. Therefore, unitholders would not receive a proxy or consent solicitation statement in connection with that transaction. However, we believe that it is unlikely that circumstances requiring an automatic transfer will occur. A transfer to corporate form would result in Great Lakes, Northern Border, North Baja or Tuscarora being subject to corporate income taxes and would likely be materially adverse to their, and therefore, our results of operations and financial condition.

TransCanada controls our general partner, which has sole responsibility for conducting our business and managing our operations. TC PipeLines GP, 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 TC PipeLines GP and its affiliates have duties to manage TC PipeLines GP in a manner that is beneficial to its stockholders. At the same time, TC PipeLines GP has duties to manage our partnership in a manner that is beneficial to us. Therefore, TC PipeLines GP's duties to us may conflict with the duties of its officers and directors to its stockholders. Such conflicts may include, among others, the following:

- expenditures, borrowings, issuances of additional common units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and TC PipeLines GP;

- under our partnership agreement, TC PipeLines GP determines which costs incurred by it and its affiliates are reimbursable by us;

- affiliates of TC PipeLines GP may compete with us in certain circumstances;

- TC PipeLines GP may limit our liability and reduce their 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;

- we do not have any employees and we rely solely on TC PipeLines GP and its affiliates to conduct our business, and

- TransCanada, through wholly-owned subsidiaries, is the operator of all of our pipeline systems. This operator role along with its ownership interests in our pipeline systems may force TransCanada to make decisions that may conflict as operator and/or owner of these systems.

Cost reimbursements due to our general partner may be substantial and could reduce our cash available for distribution.

Prior to making any distribution on the common units, we will 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, 2009, we paid fees and reimbursements to our general partner in the amount of $2.1 million (2008 $2.1 million). Our general partner in its sole discretion will determine the amount of these expenses. In addition, our general partner and its affiliates may provide us 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.

If we were found to be an "investment company" under the Investment Company Act of 1940, our contracts may be voidable and our offers of securities may be subject to rescission.

If we were deemed to be an unregistered "investment company" under the Investment Company Act, our contracts may be voidable and our offers of securities may be subject to rescission, and we may also be subject to other materially adverse consequences.

Our assets include a 46.45 per cent general partner interest in Great Lakes and a 50 per cent general partner interest in Northern Border. We could be deemed to be an "investment company" under the Investment Company Act if these interests constituted an "investment security", as defined in the Investment Company Act. If we were deemed to be an "investment company", then we would be required to be registered as an investment company under the Investment Company Act. In that case, there would be a substantial risk that we would be in violation of the Investment Company Act because of the practical inability to register under the Investment Company Act.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Tax Risks to Common Unitholders

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 and state income taxes on our income at the applicable corporate tax rate. 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.

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, 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 are evaluating a variety of ways to subject partnerships to entity level taxation. For example, in 2009, Great Lakes recorded a Michigan business tax of $5.4 million relating to a partnership level tax, adopted by Michigan in 2008, of which the Partnership's share of the tax was $2.5 million. 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 our counsel's conclusions or 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 some or all of the unitholders and the general partner.

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

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 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 unitholders were allocated for a common unit which decreased their 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, whether or not representing a gain, may be ordinary income to unitholders. If the IRS successfully contests some conventions we use, unitholders could recognize more gain on the sale of common units than would be the case under those conventions without the benefit of decreased 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 is 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.

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 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 Section 743(b) adjustments and Section 751 deemed sale tax effects.

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 of 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 per cent 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 per cent 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, Illinois, Indiana, Iowa, Michigan, Minnesota, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, Texas, and Wisconsin. Each of these states except for Nevada, South Dakota, and Texas, 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 our properties and the properties of our pipeline systems is included in Part 1, Item "Business", and is incorporated herein by reference.

We believe that our pipeline systems have satisfactory title to the properties owned and used in their businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our pipeline systems' businesses. We believe that our pipeline systems' properties are adequate and suitable for the conduct of their business in the future.

Item 3. Legal Proceedings

Great Lakes Rate Case (RP10-149-000). In November 2009, the FERC issued an order instituting an investigation, pursuant to Section 5 of the Natural Gas Act, to determine whether the rates currently charged by Great Lakes are just and reasonable. On February 4, 2010, Great Lakes filed a cost and revenue study (GL Cost and Revenue Study) in response to the November 2009 Order. The GL Cost and Revenue Study supports Great Lakes' current rates and shows that if Great Lakes filed to reset its rates, these rates should be above Great Lakes' current rates. The GL Cost and Revenue Study reflects the increased risk of de-contracting on the Great Lakes system which may result in decreases to overall long-term, daily and short-term firm transportation revenues, and interruptible transportation revenues, as compared to prior years. In the absence of a settlement, a hearing is scheduled for early August 2010 and an initial decision by the Administrative Law Judge is expected in November 2010. Should the FERC determine as a result of these proceedings, that Great Lakes' rates are not just and reasonable; the FERC could order Great Lakes to reduce its rates prospectively. Great Lakes has expressed interest in entering into settlement discussions with the FERC staff and interveners, which includes certain of its shippers.

TransCanada owns a 53.55 percent partner interest in Great Lakes. TransCanada, Great Lakes' largest shipper, and ANR, an affiliate of Great Lakes and a shipper on Great Lakes, have filed interventions in the GL Rate Proceeding.

Great Lakes v. Essar Steel Minnesota LLC, et.al. (Essar). In October 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar for breach of contract. Essar is a party to a transportation contract for a term starting July 1, 2009 through March 31, 2024. The total contract value is $33.7 million. Essar has refused to honor their contractual obligations. Great Lakes is seeking recovery of all sums due, including all future sums due under the contract.

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

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders, through solicitation of proxies or otherwise, during the year ended December 31, 2009.

PART II

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

The common units representing limited partner interests in the Partnership have been quoted on the NASDAQ Global Select Market since May 1999 and trade under the symbol "TCLP."

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported by the NASDAQ Global Select Market, and the amount of cash distributions per common unit declared 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	
2009			
First Quarter	**$30.44**	**$23.62**	**$0.705**
Second Quarter	**$36.43**	**$29.71**	**$0.730**
Third Quarter	**$39.14**	**$34.82**	**$0.730**
Fourth Quarter	**$41.10**	**$35.17**	**$0.730**
2008			
First Quarter	$37.30	$31.60	$0.700
Second Quarter	$36.96	$33.75	$0.705
Third Quarter	$34.98	$30.42	$0.705
Fourth Quarter	$31.72	$18.82	$0.705

As of February 18, 2010, there were 100 registered holders of common units and approximately 21,500 beneficial owners of common units, including common units held in street name.

The Partnership currently has 46,227,766 common units outstanding, of which 29,142,935 are held by the public, 11,287,725 are held by TransCan Northern Ltd., and 5,797,106 are held by TC PipeLines GP, Inc. The common units represent an aggregate 98 per cent limited partner interest and the general partner interest represents an aggregate two per cent general partner interest in the Partnership.

The general partner receives two per cent of all cash distributions in regards to its general partner interest and is also entitled to incentive distributions as described below. The holders of common units (unitholders) receive the remaining portion of the cash distribution. The Partnership's quarterly cash distributions to its unitholders comprise all of its Available Cash. Available Cash is defined in the partnership agreement and generally means, with respect to any quarter of the Partnership, 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 the business of the Partnership (including reserves for future capital expenditures and for anticipated credit needs);
- comply with applicable laws or any Partnership debt instrument or agreement; and
- provide funds for cash distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

The incentive distribution provisions were amended in July 2009. As a result, the general partner receives 15 per cent of quarterly amounts distributed in excess of $0.81 per common unit, and a maximum of 25 per cent 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 2009, the Partnership made cash distributions to unitholders and the general partner that amounted to $117.0 million compared to $108.6 million in 2008. These payments represented $0.705 per common unit for the quarters ended December 31, 2008 and March 31, 2009, and $0.73 per common unit for the quarters ended June 30, 2009 and September 30, 2009. On February 12, 2010, the Partnership paid a cash distribution of $34.4 million to unitholders and the general partner, representing a cash distribution of $0.73 per common unit for the quarter ended December 31, 2009. The distribution was allocated in the following manner: $33.7 million to the holders of common units as of the close of business on January 31, 2010 (including $4.2 million to the general partner as holder of 5,797,106 common units and $8.2 million to TransCanada Corporation as indirect holder of 11,287,725 common units), and $0.7 million to the general partner in respect of its two per cent general partner interest.

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 unit amounts)	**2009**[(a)]	2008[(a)]	2007[(a)(b)]	2006[(a)(c)]	2005[(a)]
Income Data ***(for the year ended December 31)***					
Equity income from investment in Great Lakes	**59.1**	57.3	49.0		
Equity income from investment in Northern Border	**40.3**	65.3	61.2	56.6	45.7
Equity income from investment in Tuscarora				5.9	7.5
Transmission revenues	**67.9**	64.5	49.8	23.0	20.3
Financial charges, net and other	**(29.3)**	(34.6)	(38.7)	(21.7)	(6.6)
Net income	**106.1**	123.0	94.7	49.1	52.8
Basic and diluted net income per unit	**$2.34**	$2.73	$2.48	$2.39	$2.70
Cash Flow Data ***(for the year ended December 31)***					
Cash distribution paid per unit	**$2.870**	$2.775	$2.565	$2.325	$2.300
Balance Sheet Data ***(at December 31)***					
Total assets	**1,675.1**	1,701.1	1,732.4	1,008.1	547.1
Long-term debt (including current maturities)	**541.3**	536.8	573.4	468.1	13.5
Partners' equity	**1,103.5**	875.6	900.1	303.9	301.6

(a) Recast as discussed in Note 2 and Note 6 of the Partnership's Financial Statements included elsewhere in this report.

(b) The Partnership acquired a 46.45 per cent interest in Great Lakes on February 22, 2007. The equity method is used to account for the Partnership's investment in Great Lakes.

(c) The Partnership acquired an additional 20 per cent interest in Northern Border on April 6, 2006. The Partnership accounted for its investment in Tuscarora using the equity method until December 19, 2006 and began consolidating Tuscarora's operations upon acquisition of the additional 49 per cent general partner interest.

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

The following discussions of the financial condition and results of operations of the Partnership and its pipeline systems should be read in conjunction with the financial statements and notes thereto of the Partnership, Great Lakes and Northern Border included elsewhere in this report. See Item 8. "Financial Statements and Supplementary Data". For more detailed information regarding the basis of presentation for the following financial information, see the notes to the financial statements of the Partnership, Great Lakes and Northern Border. The discussion below includes forward-

looking statements that are subject to risks and uncertainties that may result in actual results differing from the statements we make. These risks and uncertainties are discussed further in Part 1, Item 1A. "Risk Factors".

OVERVIEW

TC PipeLines, LP was formed in 1998 as a Delaware limited partnership by TransCanada to acquire, own and participate in the management of energy infrastructure businesses in North America. Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

To date, our investments have been in interstate natural gas pipeline systems that transport natural gas to a variety of markets in the United States, Eastern Canada and Mexico. Our pipeline systems derive their operating revenue from the transportation of natural gas. They are regulated by the FERC and are operated by TransCanada. Our investments are summarized below.

	Ownership		System Specifications	
	Percentage	**Date Acquired**	**Miles**	**Capacity (MMcf/d)**
Great Lakes	46.45	February 2007	2,115	2,300 (summer design) 2,500 (winter design)
Northern Border	30.00 20.00 50.00	May 1999 April 2006	1,249	2,374 (design)
North Baja	100.00	July 2009	80	500 (FERC licensed southbound) 600 (northbound design)
Tuscarora	49.00 49.00 2.00 100.00	September 2000 December 2006 December 2007	240	230 (design)

Year in Review

Equity Issuances: In 2009, we issued a total of 11,371,680 common units in three transactions (1) a private placement on July 1, 2009 to our general partner in consideration for the restructuring of the incentive distribution rights; (2) a private placement on July 1, 2009 to an affiliate of TransCanada, as part of the financing for the North Baja acquisition; and (3) a public offering on November 18, 2009, the proceeds of which were used to pay down debt.

North Baja Acquisition: We acquired 100 per cent of North Baja on July 1, 2009 from TransCanada for a purchase price of approximately $271 million. We agreed to purchase an expansion project (Yuma Lateral) which is expected to be completed in March 2010 for an additional sum up to $10 million. Because North Baja was acquired from an affiliate, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of 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.

IDR Restructuring: The Partnership entered into an exchange agreement with its general partner whereby the Partnership issued 3,762,000 new common units to the general partner and provided for revised incentive distribution rights (Revised IDRs) in exchange for the cancellation of the incentive distribution rights available to the general partner (Old IDRs) under the Amended and Restated Agreement of Limited Partnership of the Partnership. Under the terms of the Revised IDRs, the distributions to the general partner were reset to two per cent, down from the general partner distribution levels of the Old IDRs at 50 per cent (for combined general partner interest and incentive distribution interest). The incentive distribution levels of the Revised IDRs will result in increased combined distributions to the general partner (for general partner interest and incentive distribution interest) of 15 per cent and a maximum of 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit, or $3.24 and $3.52 per common unit on an annualized basis, respectively.

Partnership Agreement Amended and Restated: The Partnership's Amended and Restated Agreement of Limited Partnership was amended and restated effective July 1, 2009 to reflect the Revised IDRs.

Northern Border Performance: Our equity income from Northern Border decreased $25.0 million, of which $22.0 million was as a result of reduced revenues due to increased competition and lower demand in the North American natural gas markets.

Great Lakes Contracting: On November 3, 2009, Great Lakes and TransCanada extended contracts until October 31, 2011 for 470 MDth/d of long haul capacity, which would have expired on October 31, 2010. Great Lakes has 486 MDth/d of long haul capacity and 110 MDth/d of short haul capacity under contracts expiring on October 31, 2010.

Great Lakes Rate Proceeding: On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 (November 2009 Order) instituting an investigation, pursuant to Section 5 of the Natural Gas Act (GL Rate Proceeding) against three pipeline companies, including Great Lakes. The FERC alleged, based on a review of certain historical information, that revenues might substantially exceed the pipelines' actual cost of service and therefore may be unjust and unreasonable. In the absence of a settlement, a hearing in the GL Rate Proceeding is scheduled for early August 2010 and an initial decision by the Administrative Law Judge is expected in November 2010. Should the FERC determine as a result of these proceedings, that Great Lakes' rates are not just and reasonable, the FERC could order Great Lakes to reduce its rates prospectively.

FACTORS THAT IMPACT OUR BUSINESS

Our general partner interests in Great Lakes and Northern Border, and ownership of North Baja and Tuscarora represent our only material assets at December 31, 2009. As a result, we are dependent upon our pipeline systems for our results of operations and all of our available cash. Key factors that impact our business are the cash flows received from our investments and our ability to maintain a strong and balanced financial position. These factors determine our ability to maintain a prudent level of available cash to make distributions to our unitholders, fund future growth, and broaden our asset base in a disciplined and focused manner. Cash flows from our investments are dependent upon the ability of Great Lakes and Northern Border to make distributions to us and of North Baja and Tuscarora to generate positive operating cash flows.

We believe our strong financial position, including available unused capacity on our credit facility, gives us the capacity to pursue opportunities to grow in a sustained and disciplined manner for the long-term benefit of our unitholders.

FACTORS THAT IMPACT THE BUSINESS OF OUR PIPELINE SYSTEMS

Our pipeline systems provide natural gas transportation services to their customers. The majority of these services are provided through firm service transportation contracts with a reservation charge to reserve pipeline capacity, regardless of use, for the term of the contract. The revenues associated with capacity under firm service transportation contracts are not subject to fluctuations caused by changing supply and demand conditions, competition, and customers.

The following table provides information with respect to the revenue composition for our pipeline systems for the year ended December 31, 2009 as well as an indication of the proportion of capacity subscribed under firm contracts and their weighted average remaining contract life as at January 31, 2010.

		2009 Revenue Composition			As at January 31, 2010	
		Firm Contracts				
	Our Ownership Interest	Capacity Reservation Charges	Variable Usage Fees	Interruptible Contracts & Other Services	Firm Contracted Capacity % [(a)]	Weighted Average Remaining Contract Life (in Years) [(c)]
Great Lakes	46.45%	97%	2%	1%	89%	2.0
Northern Border	50%	85%	10%	5%	69%	1.9
North Baja	100%	97%	2%	1%	79% southbound [(b)] 64% northbound	16.7
Tuscarora	100%	100%	0%	0%	97%	10.6

(a) Firm contracted capacity is calculated based upon contracted capacity compared to design capacity for Northern Border, North Baja northbound transportation and Tuscarora, compared to average design capacity for Great Lakes, and compared to FERC licensed capacity for North Baja southbound transportation.

(b) Due to North Baja's bi-directional nature, it can contract for both southbound and northbound capacity separately.

(c) Weighted average remaining contract life is weighted based upon maximum daily quantity (MDQ) in the contracts.

Key factors that impact the business of our pipeline systems are the level of capacity under firm contracts, supply of and demand for natural gas in the markets in which our pipeline systems operate, competition, and customers and the mix of services they require. Government regulation of natural gas pipelines is also a major factor impacting the business of our pipeline systems. These factors are discussed in more detail below.

When there is capacity that is not contracted under firm service transportation contracts, there is exposure to fluctuations in earnings caused by changes in the above key factors. Our North Baja and Tuscarora pipeline systems have little risk of fluctuations in revenues as a result of their strong contracted capacity position and long-term contract lives. As well, our North Baja pipeline system does not transport WCSB natural gas and is therefore not impacted by WCSB supply conditions.

Government regulation of natural gas pipelines includes, among others, regulation of the terms of and rates for interstate natural gas transportation services, environmental issues, pipeline safety and integrity.

Natural Gas Supply and Demand

Decreased demand for natural gas in North America related to the economic environment, combined with increased production from U.S. shale gas developments and high levels of natural gas in storage have contributed to weaker commodity prices for natural gas over the last year. This trend is expected to continue in 2010.

The primary source of natural gas transported by our pipeline systems, excluding North Baja, is the WCSB. Gas exiting the WCSB is dependent upon WCSB natural gas production levels, demand for natural gas in Western Canada, and natural gas storage capacity and demand for natural gas storage injection in Western Canada. Gas exiting the WCSB was lower in 2009 compared to 2008, due mainly to a decrease in production. Decreases in WCSB production are expected to continue in 2010 as a result of a decline in drilling and exploration activity for natural gas in 2008 and 2009 as well as some voluntary production curtailments by WCSB producers in 2009, mainly due to lower natural gas prices. Decreases in WCSB production are also related to higher supply costs, including higher royalties, and competition for capital from other North American basins that have lower exploration costs and lower end market transportation costs.

Factors which may support increased WCSB production in the future include strengthening gas prices, which would support continued exploration and development of new fields in Western Canada by WCSB natural gas producers. Drilling in the WCSB is expected to recover in the ensuing years if gas prices stabilize and that exploration and development costs become more economical. Over the long term, we expect WCSB natural gas producers will direct significant resources toward development of unconventional resources such as coalbed methane and shale gas. Additional natural gas supply from the Alberta Hub is expected to be available in the future when new pipeline projects associated with the Montney and Horn River shale gas regions in Western Canada are constructed, or if the longer term potential associated with the proposed development of the Mackenzie Delta in Northern Canada and the North Slope in Alaska is realized.

Levels of Western Canadian natural gas in storage in 2009 were at five year highs. U.S. working gas storage levels were also at record highs. The high demand period for storage injection usually begins in the spring and extends through most of the summer. However, due to the high levels of natural gas already in storage in Western Canada at the beginning of the 2009 storage injection season, lower amounts of gas were injected during the traditional storage injection period than in previous years. Normally, lower levels of injection into Western Canadian gas storage results in more WCSB gas available for export; however, this was offset by less WCSB production in 2009. The high U.S. gas storage levels are negatively impacting the demand for natural gas in the market areas that storage serves, as well as reducing demand for transportation services related to storage injection. High overall storage levels have a dampening effect on natural gas prices which in turn reduces ongoing production. As the demand for natural gas increases, both through short-term weather related demand as well as over the long term from other natural gas demand factors, it is expected that the levels of natural gas in storage will be reduced and the demand for this type of transportation service will increase.

Continued strengthening of the North American economy and decreased natural gas inventories resulting from reduced production levels and cold winter weather related demand are factors that would positively affect natural gas prices in the near term.

North America's demand for natural gas is expected to rise when the economy returns to growth mode. The relative environmental merits of natural gas versus other carbon based forms of energy are also expected to increase the demand for natural gas.

There was an increase in U.S. natural gas production in 2009 compared to 2008, mainly due to the enhanced productivity of new wells being drilled to develop unconventional resources in the lower-48 States. Production from natural gas basins other than the WCSB represents supply competition for WCSB natural gas. Overall, U.S. natural gas production is expected to decrease somewhat in 2010 compared to recent years. Production from individual natural gas basins in North America will depend on factors including natural gas drilling activity, well production rates, and relative operating costs with reduced natural gas drilling activity in North America as a whole expected to contribute to lower production overall.

The changing geography and quantity of supply from various basins have resulted in new pipeline projects which have impacted and will continue to impact the overall natural gas transportation infrastructure and the relative competitive positions of our pipeline systems.

Demand for Transportation Services and Contracting

Demand for natural gas transportation service on our pipeline systems is directly related to the activity in the natural gas markets served by these systems. Factors that may impact demand for transportation service on any one system include the availability of natural gas supply at the pipeline system's receipt points, the ability and willingness of natural gas shippers to utilize that system over alternative pipelines, relative transportation rates, and the volume of natural gas delivered to markets supplied by that system from other supply sources and storage facilities. The impact of changes in demand for natural gas transportation services on operating revenues for our pipeline systems is dependent upon the extent to which capacity has been contracted under long-term firm contracts. Contracted capacity and system throughput are measures of demand for natural gas transportation services.

The reduced level of gas exiting the WCSB has resulted in excess pipeline capacity serving the WCSB. We anticipate there will be excess natural gas pipeline capacity serving the WCSB for the foreseeable future and therefore competition for gas exiting the WCSB will continue. In this environment, there is little incentive for shippers to make long-term commitments for capacity and the trend towards shorter term contracts is expected to continue for Great Lakes and Northern Border. As a result, there may be increased volatility and seasonality with respect to throughput and revenues for these pipelines.

Prevailing market conditions and dynamic competitive factors in North America, particularly reduced gas exiting the WCSB, increased supply from other supply basins to our pipeline systems' market areas, and the economic environment affecting the demand for natural gas, will continue to impact the value of transportation on our pipeline systems and their ability to market available capacity.

Great Lakes

Great Lakes' average contracted capacity was 100 per cent of its average design capacity for 2009, consistent with 2008. As at January 31, 2010, 89 per cent of its average design capacity was contracted on a firm basis with a weighted average remaining contract life of 2.0 years. On November 1, 2010, the per cent of average design capacity contracted on a firm basis decreases to 68 per cent.

Great Lakes had approximately 990 MDth/d of long haul capacity expiring on October 31, 2010, of which 831 MDth/d, representing 36 per cent of Great Lakes' average design capacity, was contracted with TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts through October 31, 2011 for 470 MDth/d of capacity, or 20 per cent of average design capacity, some at a slightly discounted rate, and agreed that Great Lakes would provide other transportation services. TransCanada elected to turn back 361 MDth/d, or 16 per cent of average design capacity, as of October 31, 2010. Of the remaining long haul capacity expiring on October 31, 2010, 125 MDth/d was turned back.

In addition to the long haul contract expiries, Great Lakes has an additional 110 MDth/d of short haul capacity under contracts expiring on October 31, 2010. The cost and revenue study filed by Great Lakes with the FERC on February 4, 2010 reflects the increased risk of de-contracting on the Great Lakes system. Great Lakes is discounting transportation capacity as needed to optimize revenue. Great Lakes' revenue may decline in 2010 if it is unable to recontract its expiring capacity.

Throughput on Great Lakes' pipeline system in 2009 decreased to 1,992 MMcf/d compared to 2,143 MMcf/d in 2008 primarily due to underutilization of long-term firm contracts by Great Lakes' major shipper, TransCanada, related to the early fill of storage during the traditional summer storage-fill season, lower power generation demand due to the cooler than normal summer weather in the market areas served by Great Lakes, and decreased overall demand related to the economic environment. The underutilization of the long-term firm contracts was offset by daily sales of firm services in 2009. Decreases in throughput related to underutilization of long-term firm contracts have a minimal impact on revenue earned from these contracts. When the level of long-term firm contracts decreases beginning in November 2010, Great Lakes may experience increased volatility in revenues as a result of changes in throughput. As well, we do not expect the same level of opportunity for daily sales of firm services related to available capacity resulting from contract underutilization in 2010.

Northern Border

Northern Border's average contracted capacity was 68 per cent of its design capacity for 2009, compared to 90 per cent for 2008. Competition for supply from the WCSB and increased deliveries of natural gas to Midwest markets from other supply sources has impacted Northern Border's ability to contract available capacity. Northern Border's capacity to Chicago is substantially under contract for multiple years, but as there is incremental supply in the Chicago market, shippers with capacity to Chicago may choose an alternate delivery point, which is having a negative impact on Northern Border's ability to contract upstream capacity. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue. As at January 31, 2010, Northern Border had approximately 69 per cent of its design capacity contracted for the first quarter of 2010, decreasing to 36 per cent beginning in the second quarter of 2010 following contract maturities. The weighted average remaining life of Northern Border's contracts at January 31, 2010 was 1.9 years.

The Midwest markets served by Northern Border continued to be impacted in 2009 by incremental supply delivered from the Rockies natural gas basin on the Rockies Express Pipeline. The combination of growing supply from the Rockies and from ongoing shale gas developments reaching the Chicago market region through new and available pipeline capacity, together with reductions in natural gas demand resulting from the current economic environment, has negatively impacted demand for Northern Border's transportation services. Throughput on Northern Border's pipeline system in 2009 decreased to 1,708 MMcf/d compared to 2,041 MMcf/d in 2008. These supply and demand factors have the potential to maintain competitive pressures in the Midwest markets on WCSB sourced natural gas, as discussed further under "Competition".

TransCanada is pursuing the Bison Pipeline Project that will extend from the Powder River Basin producing region in Wyoming to an interconnection with the Northern Border system in Morton County, North Dakota. The FERC issued a Final Environmental Impact Statement in December 2009 and the project is in the final stages of the regulatory process. Pending these approvals, TransCanada expects to commence construction in May 2010 and the project is expected to go into service in late 2010. If completed, this project would increase Northern Border's supply diversity. Shippers on the Bison Pipeline Project have executed 10 year contracts for approximately 407 MMcf/d of capacity on the Northern Border system from Port of Morgan, Montana to Ventura, Iowa, commencing on the in-service date of the Bison Pipeline Project. If the Bison Pipeline Project is completed, this would increase Northern Border's average contracted capacity and weighted average contract life.

Competition

There is currently increased competition amongst natural gas pipelines for gas exiting the WCSB due to excess pipeline capacity. Factors impacting the competition for gas exiting the WCSB include levels of firm transportation contracts on each pipeline, demand for natural gas in the regions served by each pipeline, and relative transportation values on each pipeline. In the short term, factors impacting the competition for gas exiting the WCSB include high natural gas storage levels in Eastern Canada, Michigan and California, and changes in basis differential for each of the pipelines accessing the WCSB resulting from changes in the North American gas flows related to new pipeline infrastructure. As well, commencing January 1, 2010, one of the main pipelines accessing the WCSB, the TransCanada Mainline pipeline system, increased its rates for firm transportation services by 40 per cent. This may improve the relative competitive position of the other pipelines accessing the WCSB, including our Great Lakes and Northern Border pipeline systems.

Our pipeline systems compete primarily with other interstate and intrastate pipelines in the transportation of natural gas. Competition among natural gas pipelines is based primarily on transportation charges and proximity to natural gas supply areas and markets. Changes in North American natural gas flow patterns as a result of recent and proposed pipeline projects are changing the supply competition in the markets served by our pipeline systems. Supply competition from other natural gas sources has impacted demand for transportation on our pipeline systems. Supply competition in the Midwest markets from the Rockies Express Pipeline, along with deliveries from other supply sources via interconnecting pipelines negatively impacted Northern Border's flows and sales of available capacity in 2009 and are expected to continue to impact demand for Northern Border's transportation services in 2010. As well, growth in supplies available from other natural gas producing regions has impacted prices for natural gas delivered to some of the markets our pipeline systems serve relative to other market regions.

Government Regulation

Federal Energy Regulatory Commission Natural gas transportation is regulated by the FERC and other federal and state regulatory agencies, including the Department of Transportation. FERC regulatory policies govern the rates that pipelines are permitted to charge customers for interstate transportation of natural gas. The operation and maintenance of our pipeline systems are also regulated by the federal and state regulatory agencies.

The FERC-approved rate designs used by our pipeline systems are based upon firm service and interruptible services. Customers with firm service transportation agreements pay a fee known as a reservation charge to reserve pipeline capacity, regardless of use, for the term of their contracts. Firm service transportation customers may also pay a variable fee that is based on the distance and volume of natural gas they transport. Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed a variable fee based on distance and the volume of natural gas they transport. The majority of our pipeline systems' revenue is generated by firm service transportation agreements.

On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 instituting an investigation pursuant to Section 5 of the Natural Gas Act. The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable. On February 4, 2010, Great Lakes filed a cost and revenue study (GL Cost and Revenue Study) in response to the November 2009 Order. The GL Cost and Revenue Study supports Great Lakes' current rates, shows that if Great Lakes filed to reset its rates, these rates should be above Great Lakes' current rates. The GL Cost and Revenue Study reflects the increased risk of de-contracting on the Great Lakes system which may result in decreases to overall long-term, daily and short-term firm transportation revenues, and interruptible transportation revenues, as compared to prior periods.

In the absence of a settlement, a hearing in the GL Rate Proceeding is scheduled for early August 2010 and an initial decision by the Administrative Law Judge is expected in November 2010. Should the FERC determine as a result of these proceedings, that Great Lakes' rates are not just and reasonable; the FERC could order Great Lakes to reduce its rates prospectively. Great Lakes' has expressed interest in pursuing settlement discussions with the FERC and interveners with the aim of bringing certainty to Great Lakes rates.

TransCanada Corporation owns a 53.55 percent interest in Great Lakes. TransCanada, Great Lakes' largest shipper, and ANR, an affiliate of Great Lakes and a shipper on Great Lakes, have filed interventions in the GL Rate Proceeding.

Climate Change Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide, in areas in which our pipeline systems conduct business, could result in changes to the consumption and demand for natural gas. This could have adverse effects on our business, financial position, results of operations and prospects. Such changes could increase the costs of our pipeline systems' operations, including costs to operate and maintain facilities, install new emission controls, acquire allowances to authorize our pipeline systems' greenhouse gas emissions, pay any new taxes related to greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or to our customers, such recovery of costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC, and the provisions of any final legislation. See Item 1. "Business Environmental Matters".

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 any standardized meaning prescribed by U.S. generally accepted accounting principles (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 is the sum of net income, cash distributions received from Great Lakes and Northern Border, cash flows provided by North Baja's operating activities, and cash flows provided by Tuscarora's operating activities, less equity income from investments in Great Lakes and Northern Border, North Baja's net income and Tuscarora's net income, net of general partner distributions.

RESULTS OF OPERATIONS OF TC PIPELINES, LP

The general partner interests in Great Lakes and Northern Border, and ownership of North Baja and Tuscarora were our only material sources of income in 2009; 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, North Baja and Tuscarora. See Item 1. "Business".

Critical Accounting Policies and 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 and Northern Border 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 and Northern Border because of our ownership interests and our representation on the Great Lakes and Northern Border 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 Northern Border's balance sheet as regulatory assets. If Northern Border determines future recovery of these assets is no longer probable as a result of discontinuing application of ASC 980 or other regulatory actions, Northern Border would be required to write off the regulatory assets at that time. As of December 31, 2009, Northern Border reflected regulatory assets of $20.1 million on its balance sheet (2008 $21.7 million). These assets are being amortized as directed by the FERC in Northern Border's previous regulatory proceedings over varying time periods up to 43 years.

As at December 31, 2009 and 2008, Great Lakes, North Baja and Tuscarora did not have any regulatory assets or liabilities recorded on their respective balance sheets.

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.

Impairment of Long-Lived Assets and Goodwill

We assess our long-lived assets for impairment based on *ASC 360-10-35 Property, Plant, and Equipment Overall Subsequent Measurement*. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair value is a market-based measure of the price 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.

We assess our goodwill for impairment at least annually, based on *ASC 350 Intangibles Goodwill and Other*. An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with ASC 350, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. At December 31, 2009 and 2008, we had $130.2 million of goodwill recorded on our balance sheet related to the North Baja and Tuscarora acquisitions. No impairment of goodwill existed at December 31, 2009.

Impact of New Accounting Standards

ASC 260-10-55 Earnings Per Share Overall Implementation Guidance and Illustrations Master Limited Partnerships is effective for fiscal years beginning after December 15, 2008. The Partnership adopted the provisions of ASC 260-10-55 effective January 1, 2009. Refer to Note 10 for the impact to the Partnership's financial statements.

ASC 805 Business Combinations was issued in December 2007 and replaces prior guidance. ASC 805 retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination, with the objective of improving the relevance and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. The requirements of this standard will impact the accounting for business combinations subsequent to January 1, 2009.

NET INCOME

The Partnership uses the non-GAAP financial measure 'Net income prior to recast' as a financial performance measure. Net income prior to recast excludes North Baja's net income for periods prior to July 1, 2009, the date on which the Partnership acquired North Baja. The acquisition of North Baja from TransCanada was accounted for as a transaction under common control, similar to a pooling of interests, whereby the Partnership's historical financial information was recast to include the net income of North Baja for all periods presented, which included income which did not accrue to the Partnership's general partner interest or to the Partnership's common units, but rather accrued to North Baja's former parent.

Net income prior to recast is presented to enhance investors' understanding of the way management analyzes the Partnership's financial performance. Net income prior to recast is provided as a supplement to GAAP financial results and is not meant to be considered in isolation or as a substitute for financial results prepared in accordance with GAAP.

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.

The shaded areas in the tables below disclose the results from Great Lakes and Northern Border, representing 100 per cent of each entity's operations for the given period.

Year Ended December 31, 2009 *(millions of dollars)*	**Total**	Other Pipes[a]	Corporate[b]	Great Lakes	Northern Border[c]
Transmission revenues	**50.9**	50.9		289.7	249.2
Operating expenses	**(7.9)**	(7.9)		(66.5)	(70.8)
General and administrative	**(6.2)**		(6.2)		
	36.8	43.0	(6.2)	223.2	178.4
Depreciation	**(10.9)**	(10.9)		(58.5)	(61.9)
Financial charges, net and other	**(27.5)**	(4.1)	(23.4)	(31.9)	(34.4)
Michigan business tax				(5.4)	
				127.4	82.1
Equity income	**99.4**			59.1	40.3
Net income prior to recast	**97.8**	28.0	(29.6)	59.1	40.3
North Baja's contribution prior to acquisition[d]	**8.3**	8.3			
Net income[d]	**106.1**	36.3	(29.6)	59.1	40.3

Year Ended December 31, 2008 *(millions of dollars)*	**Total**	Other Pipes[a]	Corporate[b]	Great Lakes	Northern Border[c]
Transmission revenues	**31.6**	31.6		287.1	293.1
Operating expenses	**(5.4)**	(5.4)		(67.1)	(78.0)
General and administrative	**(4.1)**		(4.1)		
	22.1	26.2	(4.1)	220.0	215.1
Depreciation	**(6.9)**	(6.9)		(58.5)	(61.1)
Financial charges, net and other[e]	**(30.1)**	(4.3)	(25.8)	(32.6)	(21.8)
Michigan business tax				(5.5)	
				123.4	132.2
Equity income	**122.6**			57.3	65.3
Net income prior to recast	**107.7**	15.0	(29.9)	57.3	65.3

North Baja's contribution prior to acquisition[(d)]	**15.3**	15.3			
Net income[(d)]	**123.0**	30.3	(29.9)	57.3	65.3

Year Ended December 31, 2007 *(millions of dollars)*	**Total**	Other Pipes[a][f]	Corporate[b]	Great Lakes[g] Feb 23 - Dec 31	Northern Border[c]
Transmission revenues	**27.2**	27.2		236.2	309.4
Operating expenses	**(4.9)**	(4.9)		(53.7)	(83.5)
General and administrative	**(3.4)**		(3.4)		
	18.9	22.3	(3.4)	182.5	225.9
Depreciation	**(6.3)**	(6.3)		(49.4)	(60.7)
Financial charges, net and other	**(33.8)**	(4.4)	(29.4)	(27.6)	(41.1)
				105.5	124.1
Equity income	**110.2**			49.0	61.2
Net income prior to recast	**89.0**	11.6	(32.8)	49.0	61.2
North Baja's contribution prior to acquisition[d]	**5.7**	5.7			
Net income[d]	**94.7**	17.3	(32.8)	49.0	61.2

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

(b) "Corporate" includes the costs of the Partnership, but excludes the costs of its subsidiaries.

(c) The Partnership owns a 50 per cent general partner interest in Northern Border. Equity income from Northern Border includes the twelve-year amortization of a $10.0 million transaction fee paid to the operator of Northern Border at the time of the additional 20 per cent acquisition in April 2006.

(d) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, 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.

(e) In 2008, Northern Border's financial charges, net and other, included a $16.2 million gain on the sale of Bison Pipeline LLC (Bison).

(f) The Partnership owns a 100 per cent general partner interest in Tuscarora following the acquisition of an additional two per cent interest on December 31, 2007.

(g) The Partnership acquired a 46.45 per cent general partner interest in Great Lakes on February 22, 2007; therefore, the amounts for 2007 only include results for the period from February 23 to December 31, 2007.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008

Net income decreased $16.9 million to $106.1 million in 2009 compared to $123.0 million in 2008. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast decreased $9.9 million to $97.8 million in 2009 compared to $107.7 million in 2008. This decrease was primarily due to lower equity income from Northern Border, partially offset by the contribution from North Baja since the acquisition. North Baja contributed $11.6 million to the Partnership's net income subsequent to its acquisition on July 1, 2009.

Equity income from Northern Border was $40.3 million in 2009, a decrease of $25.0 million compared to 2008. A portion of this decrease in equity income was due to the Partnership's $8.1 million share of Northern Border's gain recorded on the sale of Bison in 2008. Excluding the gain, Northern Border's 2009 net income decreased $33.9 million compared to 2008 primarily due to decreased transmission revenues, partially offset by lower operating expenses and financial charges. Northern Border's transmission revenues decreased $43.9 million due to reductions in contracted capacity compared to 2008. Demand for Northern Border's transportation services, and therefore ability to contract capacity, has continued to be negatively impacted by increased U.S. natural gas supplies being transported to the Midwestern and Eastern markets from new U.S. supply sources, including the Rockies Basin and southern shale gas, which is displacing demand for gas from traditional natural gas sources including the WCSB. Reduced overall demand for natural gas related to the economic environment is also affecting demand for Northern Border's transportation. Operating expenses decreased $7.2 million in 2009 compared to 2008 primarily due to decreased property taxes and lower general and administrative costs. Excluding the gain recorded on the sale of Bison in 2008, financial charges, net and other decreased $3.5 million in 2009 compared to 2008 primarily due to lower interest rates and average debt outstanding.

Net income from Other Pipes, which includes results from North Baja and Tuscarora, was $36.3 million in 2009, an increase of $6.0 million compared to 2008. Excluding the contribution from North Baja prior to the acquisition, net income from Other Pipes, prior to recast, was $28.0 million, an increase of $13.0 million. This increase was primarily due to the acquisition of North Baja which contributed $11.6 million to net income in 2009, as well as increased transmission revenues from a full year of operation of Tuscarora's Likely compressor station expansion that went into service in April 2008.

Equity income from investment in Great Lakes was $59.1 million in 2009, an increase of $1.8 million compared to $57.3 million in 2008. The increase in equity income was primarily due to increased transmission revenues and decreased operating expenses. Transmission revenues increased primarily due to increased sales of short-term services, partially offset by decreased reservation revenues resulting from re-negotiation of contracts at lower rates and non-renewal of services. Operating expenses decreased primarily due to lower compressor fuel use tax, lower property taxes, and lower transition costs. These decreases in operating expenses were offset by increased repairs and overhauls.

Costs at the Partnership level were $29.6 million in 2009, a decrease of $0.3 million compared to 2008. This decrease was primarily due to lower financial charges, net and other, partially offset by increased operating expenses. The decrease in financial charges, net and other, was a result of lower interest rates, partially offset by higher average debt outstanding and losses on interest rate derivatives. Operating expenses increased primarily due to transaction costs relating to the North Baja acquisition and the concurrent IDR restructuring.

Year Ended December 31, 2008 Compared with the Year Ended December 31, 2007

Net income increased $28.3 million to $123.0 million in 2008 compared to $94.7 million in 2007. The accounting treatment of the North Baja acquisition resulted in $15.3 million and $5.7 million recorded in the Partnership's net income for 2008 and 2007, respectively, for the years prior to our July 1, 2009 acquisition. Net income prior to recast increased $18.7 million to $107.7 million in 2008 compared to $89.0 million in 2007. This increase was primarily due to higher income from each of our pipeline systems, combined with a reduction in financial charges, net and other at the Partnership level.

Equity income from investment in Great Lakes was $57.3 million in 2008, an increase of $8.3 million compared to $49.0 million for the period February 23 to December 31, 2007. The increase in equity income was primarily due to the timing of the Great Lakes acquisition, which resulted in less than a full year of income contribution in 2007. In addition, Great Lakes experienced an overall increase in transmission revenues in 2008 as compared to 2007, offset by increased operating expenses and the implementation of Michigan Business Tax. Transmission revenues increased primarily due to increased sales of short-term firm transportation services at higher average transportation rates, as well as increased sales of interruptible transportation services and storage related services, offset by decreased long-term services. Operating expenses increased primarily due to integration costs related to its acquisition, employee benefit costs, and pipeline inspection costs, partially offset by decreased property and other non-income taxes and lower main engine repair costs. In 2008, Great Lakes recorded Michigan Business Tax of $5.5 million.

Equity income from investment in Northern Border was $65.3 million in 2008, an increase of $4.1 million compared to 2007. The increase in equity income was primarily due to the Partnership's $8.1 million share of Northern Border's gain on the sale of Bison. Excluding this gain, Northern Border's net income decreased $4.0 million compared to the prior year due to a $16.3 million decrease in transmission revenues, partially offset by decreased financial charges and operating expenses. Northern Border's transmission revenues decreased in 2008 compared to the prior year primarily due to a decrease in contracted capacity as natural gas supply transported from the Rockies basin into the Mid-Continent market on the Western segment of the Rockies Express Pipeline impacted demand. Interest expense decreased in 2008 compared to the prior year due to lower interest rates. Operating expenses decreased in 2008 compared to 2007 primarily due to decreased property taxes and a $2.3 million transition related charge in 2007 related to the reimbursement for shared equipment and furnishings, partially offset by increased electric compressor charges.

Net income from Other Pipes was $30.3 million in 2008, an increase of $13.0 million compared to 2007. The accounting treatment of the North Baja acquisition resulted in $15.3 million and $5.7 million recorded in the Partnership's net income for 2008 and 2007, respectively, for the years prior to our July 1, 2009 acquisition. Net income from Other Pipes, prior to recast, was $15.0 million in 2008, an increase of $3.4 million compared to 2007. This increase was primarily due to increased transmission revenues related to a full year of operation of Tuscarora's Likely compressor station expansion that went into service in April 2008.

Costs at the Partnership level were $29.9 million in 2008, a decrease of $2.9 million compared to 2007. This decrease related primarily to lower financial charges as a result of lower interest rates and average debt outstanding, partially offset by losses on interest rate derivatives.

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, less North Baja's net income contribution prior to acquisition, plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja and Tuscarora, and cash distributions received in excess of equity income from the Partnership's equity investments, Great Lakes and Northern Border, 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 Net Income Prior to Recast and Partnership Cash Flows

Year Ended December 31 *(millions of dollars except per common unit amounts)*	**2009**	2008	2007
Net income[a]	**106.1**	123.0	94.7
North Baja's contribution prior to acquisition[a]	**(8.3)**	(15.3)	(5.7)
Net income prior to recast	**97.8**	107.7	89.0
Add:			
Cash distributions from Great Lakes[b]	**72.5**	73.9	61.3
Cash distributions from Northern Border[b]	**75.7**	90.7	86.3
Cash flows provided by North Baja's operating activities	**15.7**		
Cash flows provided by Tuscarora's operating activities	**23.7**	21.5	17.6
	187.6	186.1	165.2
Less:			
Equity income from investment in Great Lakes	**(59.1)**	(57.3)	(49.0)
Equity income from investment in Northern Border	**(40.3)**	(65.3)	(61.2)
North Baja's net income	**(11.6)**		
Tuscarora's net income	**(16.4)**	(15.0)	(11.6)
	(127.4)	(137.6)	(121.8)
Partnership cash flows before general partner distributions	**158.0**	156.2	132.4
General partner distributions[c]	**(7.8)**	(12.7)	(9.2)
Partnership cash flows	**150.2**	143.5	123.2
Cash distributions declared	**(123.6)**	(110.8)	(101.0)
Cash distributions declared per common unit[d]	**$2.895**	$2.815	$2.630
Cash distributions paid	**(117.0)**	(108.6)	(86.7)
Cash distributions paid per common unit[d]	**$2.870**	$2.775	$2.565

(a) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, 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.

(b) In accordance with the cash distribution policies of the respective pipeline systems, cash distributions from Great Lakes and Northern Border are based on their respective prior quarter financial results, except that the distribution paid by Northern Border in the third quarter of 2008 included a special distribution of $16.4 million (Partnership share $8.2 million) related to the sale of Bison.

(c) General partner distributions represent the cash distributions declared to the general partner with respect to its two per cent interest plus an amount equal to incentive distributions. Prior to 2009, General partner distributions were based on the cash distributions paid during the quarter to the general partner. As a result of the retrospective application of ASC 260-10-55, General partner distributions for the years ended December 31, 2008 and 2007 increased from $11.8 million to $12.7 million and from $7.7 million to $9.2 million, respectively.

(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 per cent interest plus an amount equal to incentive distributions.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008

Partnership cash flows increased $6.7 million to $150.2 million in 2009 compared to $143.5 million in 2008. This increase was primarily due to $15.7 million of cash flows provided by North Baja's operating activities since the Partnership's July 1, 2009 acquisition, a decrease of $4.9 million in general partner distributions resulting from the restructuring of IDRs on July 1, 2009 and an increase of cash flows provided by Tuscarora's operating activities of $2.2 million. These positive factors were partially offset by decreased cash distributions from Northern Border of $15.0 million. Northern Border's decreased cash distributions were due to a special one-time $8.2 million distribution for the proceeds received in connection with the sale of Bison in 2008 and lower net income in 2009 as compared to 2008, partially offset by a reduction in maintenance capital expenditures.

The Partnership paid distributions of $117.0 million in 2009, an increase of $8.4 million compared to 2008 due to an increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts.

Other Cash Flows

On July 1, 2009, the Partnership acquired North Baja with proceeds from equity issuances of $80.0 million, including the general partner's contribution to maintain its two per cent interest, a $170.0 million draw on its revolving credit facility and cash on hand. In 2009, the Partnership made equity contributions to Northern Border totaling $42.3 million to partially fund the repayment of Northern Border's $200.0 million of debt which matured on September 1, 2009 and to complete the Des Plaines Project. In the fourth quarter of 2009, net proceeds from equity issuances of $185.5 million, including the general partner's contribution to maintain its two per cent interest, were used to repay long-term debt outstanding on the Partnership's revolving portion of its senior credit facility.

Year Ended December 31, 2008 Compared with the Year Ended December 31, 2007

Partnership cash flows increased $20.3 million to $143.5 million in 2008 compared to $123.2 million in 2007. This increase was a result of increased cash distributions from Great Lakes and Northern Border, increased cash flows provided by Tuscarora's operating activities and decreased costs at the Partnership level.

Cash distributions from Great Lakes were $73.9 million in 2008, an increase of $12.6 million compared to 2007. The increase in cash distributions from Great Lakes is due primarily to a full year of ownership in 2008. Cash distributions from Northern Border increased $4.4 million to $90.7 million in 2008 compared to 2007 due primarily to the special distribution of $8.2 million received in relation to the gain on the sale of Bison. Cash flows provided by Tuscarora's operating activities were $21.5 million in 2008, an increase of $3.9 million compared to 2007 primarily due to additional transmission revenues resulting from the Likely compressor station expansion. Costs at the Partnership level decreased by $2.9 million to $29.9 million in 2008 compared to 2007 primarily due to lower financial charges as a result of lower interest rates and average debt outstanding, partially offset by losses on interest rate derivatives.

The Partnership paid distributions of $108.6 million in 2008, an increase of $21.9 million compared to 2007 due to an increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts.

Other Cash Flows

In 2008, Tuscarora made capital expenditures of $6.8 million that related primarily to the Likely compressor station expansion, compared to $13.2 million in 2007. In February 2007, the Partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation for $733.0 million in cash. In April 2007, the Partnership made a contribution of $7.5 million to Northern Border, representing the Partnership's 50 per cent share of a $15.0 million cash call issued by Northern Border.

In 2007, the proceeds from net equity issuances of $607.0 million, including the general partner's contribution to maintain its two per cent interest, were used to acquire Great Lakes. The Partnership funded the balance of the acquisition cost with a draw on its revolving credit and term loan agreement. The Partnership repaid a net $36.6 million of the outstanding balance on its debt in 2008.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES, LP

Overview

Our principal sources of liquidity include distributions received from our investments in Great Lakes and Northern Border, operating cash flows from North Baja and Tuscarora, 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.

Summary of the Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2009 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 2011	484.0		484.0		
7.13% Series A Senior Notes due 2010	48.2	48.2			
7.99% Series B Senior Notes due 2010	4.4	4.4			
6.89% Series C Senior Notes due 2012	4.7	0.8	3.9		
Interest payments on Senior Credit Facility[(a)]	35.2	18.6	16.6		
Interest payments on Senior Notes	4.4	4.0	0.4		
Fair value of derivative contracts[(b)]	23.8	12.9	10.9		
Operating leases	2.2	0.1	0.4	0.2	1.5
	606.9	89.0	516.2	0.2	1.5

(a) Interest payments on Senior Credit Facility include the hedging effect of the derivative financial instruments placed on all of the outstanding debt. Refer to the Interest Rate Swaps and Options section below for details of the hedges. The weighted average interest rate incurred for the quarter ended December 31, 2009 of 0.8983% was used to calculate interest payments for all unhedged debt. The interest payment calculation assumes no principal repayments until maturity.

(b) The anticipated timing of settlement of the fair value of derivative contracts assumes no changes in interest rates from December 31, 2009.

North Baja At the time of our acquisition of North Baja, TransCanada had begun an expansion project of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona. We agreed to acquire the expansion facilities and contracts for an additional sum up to $10.0 million, if TransCanada completed the project by June 30, 2010. The Yuma Lateral project is currently under construction and is expected to be completed in March 2010. The purchase price has yet to be determined.

The Partnership's Debt and Credit Facilities

The Partnership has a $475.0 million senior term loan and a $250.0 million senior revolving credit facility (Senior Credit Facility) with a banking syndicate. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. In 2009, none of the senior term loan was repaid (2008 $13.0 million); therefore, $475.0 million remained outstanding under the senior term loan at December 31, 2009. $9.0 million was outstanding under the revolving portion of the Senior Credit Facility at December 31, 2009 (2008 $nil), leaving $241.0 million available for future borrowings.

The Senior Credit Facility matures on December 12, 2011, subject to two one-year extensions at the option of the Partnership and with the approval of a majority of the lenders thereunder. Amounts borrowed may be repaid in part, or in full, prior to that time without penalty. Borrowings under the Senior Credit Facility bear interest based, at the

Partnership's election, on the London Interbank Offered Rate (LIBOR) or the prime rate plus, in either case, an applicable margin. There was $484.0 million outstanding under the Senior Credit Facility at December 31, 2009 (2008 $475.0 million). The interest rate on the Senior Credit Facility averaged 1.42 per cent for the year ended December 31, 2009 (2008 3.75 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.10 per cent for the year ended December 31, 2009 (2008 5.15 per cent). Prior to hedging activities, the interest rate was 0.97 per cent at December 31, 2009 (2008 2.67 per cent).

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, depreciation and amortization less equity earnings and extraordinary gains)) of no more than 4.75 to 1.00 at the end of any fiscal quarter. The permitted leverage ratio will increase to 5.50 to 1.00 for the first three fiscal reporting periods during any 12-month period immediately following the consummation of specified material acquisitions. At December 31, 2009, the Partnership was in compliance with all of its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

Series A, B and C 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. On December 21, 2010, the Series A and B Senior Notes will mature. As market conditions dictate, the Partnership intends to refinance this debt with either fixed-rate or variable-rate debt.

As of February 26, 2010, the Partnership had $6.0 million of outstanding borrowings under the $250.0 million revolving portion of the Senior Credit Facility, which expires on December 12, 2011.

Interest Rate Swaps and Options

The Partnership's long-term debt results in exposures to changing interest rates. The Partnership uses derivatives to assist in managing its exposure to interest rate risk.

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at December 31, 2009 (2008 $475.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid is 3.86 per cent. $100.0 million of variable-rate debt was hedged by an interest rate option through May 22, 2009 at an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

Under *ASC 820 Fair Value Measurements and Disclosures,* 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 where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At December 31, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $23.8 million (2008 negative $31.7 million), of which $12.9 million is classified as a current liability (2008 $11.8 million). The fair value of the interest rate swaps was calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. In 2009, the Partnership recorded interest expense of $15.1 million on the interest rate swaps and options (2008 $6.9 million).

Capital Requirements

Northern Border's distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by its management committee to establish the timing and amount of required equity contributions. In accordance with this policy, Northern Border required an equity contribution of $76.0 million in the third quarter of 2009, of which the Partnership's share was $38.0 million, to partially fund $200.0 million of debt which matured on September 1, 2009. The Partnership financed this equity contribution with a combination of debt and operating cash flows. In the first quarter of 2009, the Partnership made an equity contribution of $4.3 million to Northern Border, representing the Partnership's 50 per cent share of an $8.6 million cash call issued by Northern Border to complete the Des Plaines Project. In 2008, Northern Border did not require any equity contributions from its partners. In 2007, the Partnership made an equity contribution of $7.5 million to Northern Border, representing the Partnership's 50 per cent share of a $15.0 million cash call issued by Northern Border to repay indebtedness.

In 2009, North Baja incurred $1.1 million of capital expenditures primarily related to minor growth projects.

In 2009, Tuscarora incurred $0.8 million of capital expenditures primarily related to the replacement of electric system components at the various compressor stations. In 2008, Tuscarora incurred $6.8 million of capital expenditures (2007 $13.2 million), of which $6.7 million related to its Likely compressor station expansion (2007 $12.2 million). These capital expenditures were funded with operating cash flows.

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

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 per cent general partner interest and incentive distribution rights (IDRs), and assume our general partner has contributed any additional capital necessary to maintain its two per cent 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 per cent 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%

On July 1, 2009, in conjunction with the North Baja acquisition, the Partnership amended the IDRs held by the general partner to eliminate the 50 per cent distribution threshold and replaced it with a new maximum distribution threshold of 25 per cent (for combined general partner interest and incentive distribution interest).

2009 Fourth Quarter Cash Distribution

On January 19, 2010, the Board of Directors of the general partner declared the Partnership's fourth quarter 2009 cash distribution in the amount of $0.73 per common unit. The fourth quarter cash distribution which was paid on February 12, 2010 to unitholders of record as of January 31, 2010, totaled $34.4 million and was paid in the following manner: $33.7 million to common unitholders (including $4.2 million to the general partner as holder of 5,797,106 common units and $8.2 million to TransCanada as holder of 11,287,725 common units) and $0.7 million to the general partner in respect of its two per cent general partner interest. The cash distribution represents an annual cash distribution of $2.92 per common unit.

LIQUIDITY AND CAPITAL RESOURCES OF OUR PIPELINE SYSTEMS

Overview

Our pipeline systems' principal sources of liquidity are cash generated from operating activities, bank credit facilities and equity contributions from their partners. Our pipeline systems fund operating expenses, debt service and cash distributions to partners primarily with operating cash flow.

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' partners. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends on their financial position and general market conditions.

Our pipeline systems believe that their ability to obtain financing at reasonable rates, together with their history of consistent cash flow from operating activities, provide a solid foundation to meet their future liquidity and capital resource requirements. The Partnership's pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs, which allow them to request credit support as circumstances dictate.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations related to debt as of December 31, 2009 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
8.74% series Senior Notes due 2010 to 2011	20.0	10.0	10.0		
6.73% series Senior Notes due 2010 to 2018	81.0	9.0	18.0	18.0	36.0
9.09% series Senior Notes due 2012 to 2021	100.0			20.0	80.0
6.95% series Senior Notes due 2019 to 2028	110.0				110.0
8.08% series Senior Notes due 2021 to 2030	100.0				100.0
Interest payments on debt	322.9	31.4	58.3	52.3	180.9
	733.9	50.4	86.3	90.3	506.9

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 $221.0 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2009 (2008 $232.0 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2009.

The aggregate estimated fair value of Great Lakes' long-term debt was $491.7 million for 2009. The aggregate annual required repayment of senior notes is $19.0 million for each year 2010 through 2014. In 2009, interest expense related to Great Lakes' senior notes was $32.9 million (2008 $34.2 million; 2007 $35.1 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 related to debt, operating leases and other long-term obligations as of December 31, 2009, 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
6.24% senior notes due 2016	100.0				100.0
7.50% senior notes due 2021	250.0				250.0
$250 million credit agreement due 2012	215.0		215.0		
Interest payments on debt	264.2	26.3	51.7	50.0	136.2
Operating leases	67.1	2.2	3.8	3.8	57.3
Other long-term obligations	1.8	1.1	0.7		
	898.1	29.6	271.2	53.8	543.5

Interest Payments on Debt

The interest rate at December 31, 2009 of 0.52 per cent was used to calculate the interest payments on debt. The interest payment calculation assumes no principal repayments until maturity.

Operating Leases

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

Other

Northern Border is required to pay $3.6 million over a five year period ending in 2011 under a transition services agreement between ONEOK Partners GP, LLC (ONEOK Partners GP) and TransCanada, related to the reimbursement for shared assets acquired by ONEOK Partners to support the operations of Northern Border. In 2007, a charge of $2.3 million was recorded in operations and maintenance expense and $1.3 million was recorded as plant, property and equipment.

Amended and Restated Credit Agreement

In April 2007, Northern Border entered into a $250.0 million amended and restated revolving credit agreement (2007 Credit Agreement) with certain financial institutions. The 2007 Credit Agreement was used to refinance the outstanding indebtedness under Northern Border's $175.0 million revolving credit agreement dated as of May 2005 and was used to repay all of the $150.0 million of its 6.25 per cent Senior Notes due May 2007. The 2007 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, 2009, based on the principal commitment amount of $250.0 million, available capacity under the 2007 Credit Agreement was $35.0 million. Northern Border may, at its option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under its 2007 Credit Agreement by an aggregate amount not to exceed $100.0 million, provided that lenders are willing to commit additional amounts. At Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or the LIBOR plus an applicable margin that is based on its long-term unsecured credit ratings. The 2007 Credit Agreement permits Northern Border to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. The term of the agreement is five years, with options for two one-year extensions.

Northern Border's long-term debt arrangements contain covenants that restrict the incurrence of secured indebtedness or liens upon property by Northern Border. Under the 2007 Credit Agreement, Northern Border is required to comply with certain financial, operational and legal covenants. Among other things, Northern Border is required to maintain a leverage ratio (total debt to EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges)) of no more than 4.75 to 1. Pursuant to the 2007 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 three full calendar quarters following the acquisition. At December 31, 2009, Northern Border was in compliance with all of its financial covenants.

The fair value of Northern Border's variable rate debt was approximately the carrying value since the interest rates are periodically adjusted to reflect current market conditions. As of December 31, 2009, Northern Border's outstanding borrowings under its credit agreement were $215.0 million (2008 $181.0 million). The average interest rate on Northern Border's credit agreement at December 31, 2009 was 0.52 per cent (2008 3.36 per cent).

Interest Rate Collar Agreement

In August 2007, Northern Border entered into a zero cost interest rate collar agreement (Collar Agreement) to limit the variability of the interest rate on $140.0 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent. Northern Border designated the Collar Agreement as a cash flow hedge. At December 31, 2009, Northern Border's balance sheet reflected an unrealized loss of approximately $nil (2008 $3.6 million) with a corresponding decrease to accumulated other comprehensive loss related to the changes in fair value of the Collar Agreement since inception. In 2009, Northern Border recorded interest expense of $3.8 million under the Collar Agreement (2008 $1.7 million). The hedge was effective for the years ended December 31, 2009, 2008 and 2007; therefore, it had no impact on income due to hedge ineffectiveness.

Long-Term Financing Debt Securities

Northern Border periodically issues long-term debt securities to meet its capital resource requirements. 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.

On August 26, 2009, Northern Border issued $100.0 million of 6.24 per cent Senior Notes due August 26, 2016. The proceeds, along with equity contributions, borrowings under the 2007 Credit Agreement and cash generated from operating activities, were used to repay $200.0 million of 7.75 per cent Senior Notes due September 1, 2009. Under the new Senior Notes, Northern Border may not at any time permit debt secured by liens to exceed 20 per cent of partners' capital and may not permit total debt, at any time, to exceed 70 per cent of total capitalization. At December 31, 2009, Northern Border was in compliance with all of its financial covenants.

Northern Border's senior notes issuances of $100.0 million due in 2016 and $250.0 million due in 2021 are borrowed at fixed interest rates of 6.24 per cent and 7.50 per cent, respectively. Northern Border intends to maintain the current schedule of maturities, which will result in no gains or losses on their respective repayments. At December 31, 2009, the aggregate fair value of the outstanding senior notes was approximately $397.0 million (2008 $447.0 million). In 2009, interest expense related to the senior notes was $31.3 million (2008 $34.3 million).

CASH FROM OUR PIPELINE SYSTEMS

Cash Distribution Policies of Great Lakes and Northern Border

Distributions to partners are made on a pro rata basis according to each general partner's ownership percentage, approximately one month following the end of a quarter. Great Lakes' and Northern Border'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' or Northern Border's cash distribution policy requires the unanimous approval of their respective management committee.

Great Lakes' distribution policy is to distribute 100 per cent of distributable cash flow based generally on earnings before current income taxes and depreciation less debt repayments and capacity capital expenditures. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

Northern Border's distribution policy is to distribute 100 per cent of the distributable cash flow based on earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures and adopted certain changes related to equity contributions. The changes 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.

On February 1, 2010, a cash distribution of $33.7 million was declared and paid by Great Lakes for the fourth quarter of 2009, of which the Partnership's 46.45 per cent share was $15.7 million. On February 1, 2010, a cash distribution of $32.8 million was declared and paid by Northern Border for the fourth quarter of 2009, of which the Partnership's 50 per cent share was $16.4 million.

Investing Activities for our Pipeline Systems

Capital spending for maintenance of existing facilities and growth projects were as follows for each of our investments:

Year Ended December 31 *(millions of dollars)*	**2009**	2008	2007
Great Lakes[a]:			
Maintenance	**5.5**	12.3	16.7
Growth	**2.8**		
Great Lakes' capital spending	**8.3**	12.3	16.7
Northern Border:			
Maintenance	**6.7**	8.4	10.6
Growth	**4.4**	12.1	
Northern Border's capital spending	**11.1**	20.5	10.6
Tuscarora:			
Maintenance	**0.2**	0.1	0.1
Growth	**0.6**	6.7	13.1
Tuscarora's capital spending	**0.8**	6.8	13.2
North Baja:			
Maintenance	**0.3**	12.8	2.3
Growth	**0.8**	15.0	10.6
North Baja's capital spending	**1.1**	27.8	12.9

(a) Great Lakes' 2007 capital spending information includes only capital expenditures from February 23 to December 31, 2007.

Our pipeline systems fund their investing activities primarily with operating cash, issuances of new debt or additional borrowings under existing facilities, and equity contributions from general partners.

Great Lakes' growth capital expenditures of $2.8 million in 2009 related to a backhaul expansion project involving upgrades to facilities to increase system capabilities to provide firm backhaul transportation services. The remaining $5.5 million of Great Lakes' capital expenditures in 2009, as well as its 2008 and 2007 capital expenditures, is comprised of maintenance capital projects including compressor engine overhauls and pipeline remediation. In 2010, Great Lakes expects to invest approximately $11.2 million for maintenance capital expenditures. Approximately $7.2 million in growth capital expenditures are planned for 2010 related to the backhaul expansion project.

Northern Border's maintenance capital expenditures decreased $1.7 million in 2009 compared to 2008 due to a decrease in expenditures related to information technology assets. Growth capital expenditures in 2009 and 2008 were primarily related to spending for the Des Plaines Project. In 2010, Northern Border expects to spend approximately $18.6 million for capital expenditures. Maintenance capital expenditures are estimated at $6.2 million and include renewals and replacements of existing facilities. Northern Border plans to spend approximately $12.4 million for growth capital expenditures in 2010.

In 2009, North Baja incurred $1.1 million of capital expenditures primarily related to minor growth projects. In 2010, North Baja expects to spend approximately $0.5 million for capital expenditures, primarily related to pipe integrity program costs and system pipeline improvements. No significant growth capital expenditures are planned for 2010.

In 2009, Tuscarora incurred $0.8 million of capital expenditures primarily related to the replacement of electric system components at various compressor stations. In 2008, Tuscarora made capital expenditures of $6.8 million that related primarily to the Likely compressor station expansion compared to $13.2 million in 2007. In 2010, Tuscarora expects to invest approximately $0.4 million for maintenance capital expenditures. No significant growth capital expenditures are planned for 2010.

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" for additional information.

RELATED PARTY TRANSACTIONS

Please read Item 13. "Certain Relationships and Related Transactions, and Director Independence" for information regarding related party transactions.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

We are exposed to market risk primarily from interest rate fluctuations. Additionally, the Partnership and our pipeline systems are also exposed to other risks such as credit risk, liquidity risk, foreign exchange fluctuations and changes to natural gas prices related to the calculation of a Minnesota fuel tax, which we have determined to be less material to us and our pipeline systems. 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.

Market risk is the risk of loss arising from adverse changes in market rates. Our primary risk management objective is to protect earnings and cash flow, and ultimately unitholder value. We do not use financial instruments for trading purposes.

In accordance with *ASC 815 Derivatives and Hedging,* we record financial instruments on the balance sheet as assets and liabilities based on fair value. We estimate the fair value of financial instruments using available market information and appropriate valuation techniques. Changes in the fair value of financial instruments are recognized in earnings unless the instrument qualifies as a hedge under ASC 815 and meets specific hedge accounting criteria. Qualifying 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 AND INTEREST RATE 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 manage 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. The Partnership and our pipeline systems enter into interest rate swaps to mitigate the impact of changes in interest rates.

- 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 option agreements to mitigate the impact of changes in interest rates.

Interest rate risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in the market interest rates. 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 are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at December 31, 2009 (2008 $475.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid is 3.86 per cent. $100.0 million of variable-rate debt was hedged by an interest rate option through

May 22, 2009 at an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

At December 31, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $23.8 million (2008 negative $31.7 million), of which $12.9 million is classified as a current liability (2008 $11.8 million). The fair value of the interest rate swaps was calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. In 2009, the Partnership recorded interest expense of $15.1 million on the interest rate swaps and options (2008 $6.9 million).

At December 31, 2009, we had $484.0 million (2008 $475.0 million) outstanding on our Senior Credit Facility. Utilizing the conditions of the interest rate swaps, if LIBOR interest rates hypothetically increased by one per cent (100 basis points) compared to the rates in effect at December 31, 2009, our annual interest expense would have increased and our net income would have decreased by $1.1 million; and if LIBOR interest rates hypothetically decreased to zero per cent compared to the rates in effect at December 31, 2009, our annual interest expense would have decreased and our net income would have increased by $0.3 million. These amounts have been determined by considering the impact of the hypothetical interest rates on unhedged debt outstanding as of December 31, 2009.

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, 2009, 62 per cent of Northern Border's outstanding debt was at fixed rates (2008 71 per cent). Northern Border utilized its Collar Agreement to limit the variability of the interest rate on $140.0 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent.

If interest rates hypothetically increased by one per cent (100 basis points) compared with rates in effect at December 31, 2009, Northern Border's annual interest expense would increase and its net income would decrease by approximately $2.2 million; and if interest rates hypothetically decreased to zero per cent compared with rates in effect at December 31, 2009, Northern Border's annual interest expense would decrease and its net income would increase by approximately $0.6 million.

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

OTHER RISKS

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 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 its contracts with the Partnership or its pipeline systems. Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consist 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, 2009, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $5.4 million (2008 $2.9 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. During the deterioration of global financial markets in 2008 and 2009, we continued to closely monitor 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 fall 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, 2009, the Partnership has a committed revolving bank line of $250.0 million maturing in December 2011. As of December 31, 2009, the outstanding balance on this facility was $9.0 million. In addition, at December 31, 2009, Northern Border has a committed revolving bank line of $250.0 million maturing in April 2012. As of December 31, 2009, $215.0 million was drawn on this facility.

The state of Minnesota currently requires Great Lakes to pay use tax on the value of the shipper-provided compressor fuel burned in its Minnesota compressor engines. Great Lakes is subject to commodity price volatility and some volume volatility in determining the amount of use tax owed. If natural gas prices changed by $1 per million British thermal units, Great Lakes' annual use tax expense would change by approximately $0.6 million.

The Partnership does not have any material foreign exchange risks.

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

Based on their evaluation of the Partnership's disclosure controls and procedures as of the end of the year covered by this annual report, the principal executive officer and principal financial officer of the general partner of the Partnership have concluded that the Partnership's disclosure controls and procedures were effective in ensuring 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 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (SEC's) rules and forms and that information required to be disclosed by the Partnership in the reports that the Partnership files or submits under the Exchange Act is accumulated and communicated to the management of the general partner of the Partnership, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2009, there has been 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 chief 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, 2009 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. There were no material weaknesses.

Our independent registered public accounting firm, KPMG LLP, 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
Russell K. Girling	47	Chairman, Chief Executive Officer and Director
Mark A.P. Zimmerman	45	President
Jack F. Jenkins-Stark	59	Independent Director
David L. Marshall	70	Independent Director
Walentin (Val) Mirosh	64	Independent Director
Gregory A. Lohnes	53	Director
Kristine L. Delkus	52	Director
Steven D. Becker	59	Director
Terry C. Ofremchuk	59	Vice-President, Taxation
Sean M. Brett	44	Vice-President, Commercial Operations
Rhonda L. Amundson	48	Treasurer
Donald J. DeGrandis	61	Secretary
Robert C. Jacobucci	41	Controller, Principal Financial Officer

Mr. Girling was appointed a director of the general partner in April 1999 and Chief Executive Officer of the general partner in June 2006. He will remain in these positions until March 1, 2010. Mr. Girling's principal occupation is Chief Operating Officer of TransCanada, a position he has held since July 2009. In addition, Mr. Girling continues his role as President, Pipelines Division of TransCanada, a position he has held since June 2006. From March 2003 to June 2006, he was Executive Vice-President, Corporate Development and Chief Financial Officer of TransCanada. Mr. Girling is also a director of Agrium Inc.

Mr. Zimmerman was appointed President of the general partner in January 2007. Mr. Zimmerman's principal occupation is Vice-President, Financial Planning of TransCanada, a position he has held since July 2009. From June 2006 to July 2009, Mr. Zimmerman was Vice-President, Commercial Transactions of TransCanada. From September 2003 to June 2006, he was Director, Project Finance for TransCanada, and prior to September 2003, he was Director, Corporate Evaluations and Planning for TransCanada.

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 April 2007. Mr. Jenkins-Stark was Chief Financial Officer of Silicon Valley Bancshares (offering financial products and services, including commercial, investment, merchant and private banking and private equity services) from April 2004 to May 2007.

Mr. Marshall was appointed a director of the general partner in July 1999. Mr. Marshall is a corporate director.

Mr. Mirosh was appointed a director of the general partner in September 2004. Mr. Mirosh's principal occupation is President of Mircan Resources Ltd., a private company. From April 2008 to December 2009, he was Vice-President of NOVA Chemicals Corporation and Special Advisor to the President and Chief Operating Officer. Prior to April 2008, Mr. Mirosh was Vice-President and President of Olefins and Feedstocks, a division of NOVA Chemicals Corporation (commodity chemical company), positions he has held since July 2003. Mr. Mirosh is also a director of Superior Plus Income Fund.

Mr. Lohnes was appointed a director of the general partner in January 2007. Mr. Lohnes' principal occupation is Executive Vice-President and Chief Financial Officer of TransCanada, a position he has held since June 2006. Prior to June 2006, he was President and Chief Executive Officer of Great Lakes Gas Transmission Company.

Ms. Delkus was appointed a director of the general partner in November 2003. Ms. Delkus' principal occupation is Deputy General Counsel, Pipelines and Regulatory Affairs of TransCanada, a position she has held since September 2006. From June 2006 to September 2006, she was Vice-President, Pipeline Law and Regulatory Affairs of TransCanada. From December 2005 to June 2006, she was Vice-President, Law, Gas Transmission of TransCanada. Prior to December 2005, she was Vice-President, Law, Power and Regulatory.

Mr. Becker was appointed a director of the general partner in January 2007. Mr. Becker's principal occupation is Vice-President, Pipeline Development of TransCanada, a position he has held since June 2006. From September 2003 to January 2007, Mr. Becker was Vice-President, Business Development of the general partner. From April 2003 to June 2006, he was Vice-President, Gas Development of TransCanada.

Mr. Ofremchuk was appointed Vice-President, Taxation of the general partner in July 2007. Mr. Ofremchuk's principal occupation is Manager, Corporate Taxation of TransCanada.

Ms. Amundson was appointed Treasurer of the general partner in December 2008. Ms. Amundson's principal occupation is Manager, Capital Markets of TransCanada.

Mr. Brett was appointed Vice-President, Commercial Operations of the general partner in December 2009. Mr. Brett also currently holds the position of Director, LP Operations for TransCanada. From December 2008 to December 2009, Mr. Brett was Director, Joint Venture Management, Keystone Pipeline for TransCanada. Mr. Brett was Vice-President and Treasurer of the general partner from January 2007 to December 2008. Mr. Brett also held the position of Assistant Treasurer and Director of Capital Markets for TransCanada. Prior to January 2007, Mr. Brett held a number of positions of increasing responsibility with TransCanada's Finance and Treasury Group.

Mr. DeGrandis was appointed Secretary of the general partner in April 2005. Mr. DeGrandis' principal occupation is Corporate Secretary of TransCanada, a position he has held since June 2006. From June 2004 to June 2006, he was Associate General Counsel, Corporate Secretarial of TransCanada.

Mr. Jacobucci was appointed principal financial officer of the general partner and Controller of the general partner in November 2009. His principal occupation is Director of Pipeline Accounting for TransCanada. From November 2008 to November 2009, Mr. Jacobucci was Director, Energy Accounting of TransCanada. From February 2006 to November 2008, Mr. Jacobucci was Manager, Power Accounting and Manager, U.S. Pipeline Accounting. Prior to February 2006, Mr. Jacobucci held various senior accounting and leadership positions in TransCanada's financial reporting group.

Director and Officer Appointments

Effective March 1, 2010, Mr. Girling, Chairman and Chief Executive Officer of the general partner will resign his positions to focus on his role as Chief Operating Officer of TransCanada. Mr. Lohnes will be appointed Chairman of the general partners' board and Mr. James Baggs will be appointed as a director. Mr. Zimmerman will continue in his role as President, which he has held since January 2007, and as the principal executive officer of the Partnership, he will be responsible for all management activities previously handled by the Chief Executive Officer.

Mr. Baggs' principal occupation is Vice-President, Field Operations and Engineering for TransCanada. He has been with TransCanada for 21 years.

On November 9, 2009, Mr. Jacobucci replaced Amy W. Leong as Controller and Principal Financial Officer.

AUDIT COMMITTEE FINANCIAL EXPERT

The Board of Directors has determined that David Marshall and Jack Jenkins-Stark are "audit committee financial experts", are "independent" and are "financially sophisticated" as defined under applicable SEC and NASDAQ Stock Market Corporate Governance rules. The Board's affirmative determination for both David Marshall 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.

IDENTIFICATION OF THE 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 David Marshall, 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 NASDAQ Stock Market. 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.

CODE OF ETHICS

The Partnership believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. The employees of the general partner, as employees of TransCanada, are subject to TransCanada's Code of Business Ethics. In addition, the general partner has adopted a code of business ethics for its Chief Executive Officer, President and Principal Financial Officer and one which applies to its independent directors, being the Code of Business Ethics for Directors. All codes are published on its 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.

CORPORATE GOVERNANCE

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 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.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, as amended, requires the Partnership's directors and executive officers, and persons who beneficially own more than ten per cent 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 2009.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership, and we 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 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 Proxy Circular" on the TransCanada website at www.transcanada.com. The TransCanada "Management Proxy Circular" is produced by TransCanada pursuant to 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 CEO 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 an affiliate of our general partner who perform services on our behalf. The base salaries that are allocable to us vary for each officer or employee of an affiliate of our general partner 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 2009, 2008 and 2007 for our principal executive officer, president and principal financial officer. None of the other executive officers of our general partner allocated to us more than $100,000 related to their salary.

Summary Compensation Table

Name and Principal Position	Year	Base Salary Allocated to the Partnership: Canadian Dollars	US Dollar Equivalent	Total[(a)]
Russell K. Girling	**2009**	**75,001**	**71,663**	**71,663**
Chief Executive Officer	2008	68,251	55,733	55,733
	2007	60,250	60,973	60,973
Mark A.P. Zimmerman	**2009**	**110,004**	**105,109**	**105,109**
President	2008	108,753	88,808	88,808
	2007	102,500	103,729	103,729
Amy W. Leong	**2009**	**24,513**	**23,422**	**23,422**
Former Controller and Principal Financial Officer	2008	27,390	22,366	22,366
	2007	16,475	16,673	16,673
Robert C. Jacobucci	**2009**	**3,610**	**3,450**	**3,450**
Controller and Principal Financial Officer	2008			
	2007			

(a) The compensation of executive officers of the general partner is paid by TransCanada in Canadian dollars. The United States dollar equivalents have been calculated using the applicable December 31, 2009 noon buying rate of 0.9555 as reported by the Bank of Canada (2008 0.8166; 2007 1.0120).

We reimburse our general partner for benefit and incentive compensation expenses based on a set formula, which expenses are attributable to additional compensation paid to each of them and other compensation and 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 a TransCanada's employee savings plan, and premiums for health and life insurance. This reimbursement is determined monthly and calculated based on total monthly base salary allocated to us multiplied by a factor of 0.32 for benefits in 2009 (2008 factor of 0.35; 2007 factor of 0.38) and a factor of 0.48 for incentive compensation in 2009 (2008 factor of 0.40; 2007 factor of 0.30). The total amount reimbursed for benefits and incentive compensation was $667,059 in 2009 for all employees providing services to the Partnership, including the named officers in the above table (2008 $610,801; 2007 $548,665).

Compensation Committee Report

Neither we, nor our general partner, has 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:
Russell K. Girling
Jack F. Jenkins-Stark
David L. Marshall
Walentin Mirosh
Gregory A. Lohnes
Kristine L. Delkus
Steven D. Becker

Independent Director Compensation

Independent Director Compensation[a] **For the year ended December 31, 2009** ***(in dollars)***	***Earned or Paid in Cash***[b]	***Unit Awards***[c]	***All Other Compensation***[d]	***Total***
David L. Marshall[e]	67,000	30,000	5,814	102,814
Jack F. Jenkins-Stark[f]	69,000	30,000	10,608	109,608
Walentin (Val) Mirosh	63,000	30,000	5,814	98,814

(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 Russell K. Girling, Gregory A. Lohnes, Kristine L. Delkus and Steven D. Becker. 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, Jack F. Jenkins-Stark elected to receive half of his fees ($34,500) in Deferred Share Units. Due to this election, 999 Deferred Share Units were credited to Mr. Jenkins-Stark's account in 2009, all of which were outstanding at December 31, 2009.

(c) Amounts presented reflect the compensation expense recognized related to the Deferred Share Units granted during 2009 under the Deferred Share Unit Plan for Non-Employee Directors. On January 20, 2009, each independent director was granted 1,232 Deferred Share Units, all of which were outstanding at December 31, 2009. At December 31, 2009, David L. Marshall, Jack F. Jenkins-Stark and Walentin (Val) Mirosh held 1,993, 4,265 and 1,993 Deferred Share Units, respectively. The fair value of Deferred Share Units held by Mr. Marshall, Mr. Jenkins-Stark and Mr. Mirosh at December 31, 2009 was $67,762, $145,010 and $67,762, respectively.

(d) Amounts presented reflect Deferred Share Units credited to each independent director's account equal to the distributions payable on the Deferred Share Units previously granted or credited. In this regard, David L. Marshall and Walentin (Val) Mirosh were credited 171 Deferred Share Units in 2009, while Jack F. Jenkins-Stark was credited 312 Deferred Share Units. All Deferred Share Units credited during 2009 were outstanding at December 31, 2009.

(e) Chairman of the Audit Committee

(f) Lead Director and Chairman of the Conflicts Committee

Cash Compensation

Each director who is not an employee of TransCanada, the general partner or its affiliates (independent director) is entitled to a directors' retainer fee of $60,000 per annum, of which $30,000 is automatically granted in Deferred Share Units (see Deferred Share Units section below). The independent director appointed as Lead Director and chair of the Conflicts Committee is entitled to an additional fee of $6,000 per annum, while the independent director appointed as chair of the Audit Committee is entitled to an additional fee of $4,000 per annum. Each independent director is 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 Deferred Share Units pursuant to The TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2007).

Deferred Share Units

The TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2007) was established in 2007 with the first grant occurring in January 2008. In 2009, as part of the retainer fee, each independent director received an annual grant of Deferred Share Units with a value of $30,000.

At the time of grant, the value of a Deferred Share Unit 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 Deferred Share Unit when redeemed is equivalent to the market value of a common unit at the time the redemption takes place. Deferred Share Units cannot be redeemed until the director ceases to be a member of the Board. Directors may redeem Deferred Share Units for cash or common units at their option.

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

The following table sets forth the beneficial ownership of the voting securities of the Partnership as of February 24, 2010 by the general partner's directors, officers and certain beneficial owners. Executive officers of the general partner own shares of TransCanada, which in the aggregate amount to less than one per cent of TransCanada's issued and outstanding shares. Other than as set forth below, no person is known by the general partner to own beneficially more than five per cent of the voting securities of the Partnership.

Amount and Nature of Beneficial Ownership

Name and Business Address	Number of Common Units[(a)]	Number of DSUs[(b)]	Per cent of Class[(c)]
TransCan Northern Ltd.[(d)] 450 1st Street SW Calgary, Alberta T2P 5H1	11,287,725		24.4
TC Pipelines GP, Inc.[(e)] 450 1st Street SW Calgary, Alberta T2P 5H1	5,797,106		12.5
David L. Marshall 450 1st Street SW Calgary, Alberta T2P 5H1		2,841	*
Walentin (Val) Mirosh 10th Floor, 1000 7th Avenue SW Calgary, Alberta T2P 5L5		2,841	*
Jack F. Jenkins-Stark[(f)] 1999 Harrison Street, Suite 500 Oakland, CA 94612	4,933	5,158	*
Gregory A. Lohnes 450 1st Street SW Calgary, Alberta T2P 5H1			
Steven D. Becker 450 1st Street SW Calgary, Alberta T2P 5H1			
Russell K. Girling 450 1st Street SW Calgary, Alberta T2P 5H1	6,000		*
Kristine L. Delkus 450 1st Street SW Calgary, Alberta T2P 5H1			
James M. Baggs 450 1st Street SW Calgary, Alberta T2P 5H1			
Mark A.P. Zimmerman 450 1st Street SW Calgary, Alberta T2P 5H1			

Amount and Nature of Beneficial Ownership

Amy W. Leong 450 1st Street SW Calgary, Alberta T2P 5H1	
Robert C. Jacobucci 450 1st Street SW Calgary, Alberta T2P 5H1	
Directors and Executive officers as a Group[g][h] (15 people)	*

(a) A total of 46,227,766 common units are issued and outstanding.

(b) A deferred share unit is a bookkeeping entry, equivalent to the value of a Partnership common unit, and does not entitle the holder to voting or other shareholder rights, other than the accrual of additional deferred share units for the value of dividends. A director cannot redeem deferred share units until the director ceases to be a member of the Board. Directors can then redeem their units for cash or shares.

(c) Any deferred share units 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.

(d) TransCan Northern Ltd. is a wholly-owned indirect subsidiary of TransCanada.

(e) TC PipeLines GP, Inc. is a wholly-owned indirect subsidiary of TransCanada and owns an aggregate two per cent general partner interest of the Partnership.

(f) 4,933 common units are held by the Jenkins-Stark Family Trust dated June 16, 1995.

(g) With the exception of the one named director above and Russell K. Girling, none of the other directors and executive officers hold any common units of the Partnership.

(h) Walentin (Val) Mirosh holds 720 shares of TransCanada, Russell K. Girling holds 571,564 options and 34,220 shares of TransCanada; Kristine L. Delkus holds 110,062 options and 4,983 shares of TransCanada; Steven D. Becker holds 74,744 options and 9,953 shares of TransCanada; Terry C. Ofremchuk holds 3,750 options and 6,225 shares of TransCanada; Gregory A. Lohnes holds 145,895 options and 18,662 shares of TransCanada; Robert C. Jacobucci holds 556 shares of TransCanada; Donald J. DeGrandis holds 14,167 options and 128 shares of TransCanada; Mark A.P. Zimmerman holds 43,156 options and 379 shares of TransCanada; Rhonda L. Amundson holds 5,100 options of TransCanada and 3,223 shares of TransCanada; Sean M. Brett holds 7,000 options of TransCanada, 14,580 shares of TransCanada and 500 Series U preferred shares of TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada, and James M. Baggs holds 68,562 options and 4,055 shares of TransCanada. The directors and executive officers as a group hold 1,044,000 options of TransCanada, 97,684 shares of TransCanada and 500 Series U preferred shares of TransCanada PipeLines Limited. All options listed above are exercisable within 60 days from February 26, 2010.

* Less than one per cent.

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

At February 26, 2010, TransCanada owns 11,287,725 common units and the Partnership's general partner owns 5,797,106 common units, representing an aggregate 36.2 per cent limited partner interest in the Partnership. In addition, the general partner owns an aggregate two per cent 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 38.2 per cent by virtue of its indirect ownership of the general partner and 36.2 per cent 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 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 available cash to our general partner and its affiliates	We will generally make cash distributions 98% 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% 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 23.2347% 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 "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

The general partner maintained its two per cent general partner interest in the Partnership by contributing $3.8 million to the Partnership in connection with the public offering completed by the Partnership on November 18, 2009.

Incentive Distribution Rights Restructuring

Exchange Agreement

On July 1, 2009, the Partnership entered into an Exchange Agreement (Exchange Agreement) with the general partner pursuant to which the Partnership issued to the general partner revised incentive distribution rights (Revised IDRs) and 3,762,000 newly issued, unregistered common units representing limited partner interests in the Partnership in exchange for the cancellation of the incentive distribution rights available to the general partner (Old IDRs) under the Amended and Restated Agreement of Limited Partnership of the Partnership.

Under the terms of the Revised IDRs, the distributions to the general partner were reset to two per cent, down from the general partner distribution levels of the Old IDRs at 50 per cent (for combined general partner interest and incentive distribution interest). The incentive distribution levels of the Revised IDRs will result in increased combined distributions to the general partner (for general partner interest and incentive distribution interest) of 15 per cent and a maximum of 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit or $3.24 and $3.52 per common unit on an annualized basis, respectively. The quarterly distribution level of the Old IDRs was $0.705 per common unit or $2.82 on an annualized basis.

Second Amended and Restated Agreement of Limited Partnership

As part of the Exchange Agreement, the Partnership's Amended and Restated Agreement of Limited Partnership was amended and restated effective as of July 1, 2009 to: (i) eliminate the Old IDRs and replace them with the Revised IDRs as described above, (ii) eliminate outdated provisions, (iii) incorporate all prior amendments and changes in one document and (iv) correct typographical errors. The Second Amended and Restated Agreement of Limited Partnership dated July 1, 2009 (Partnership Agreement) replaces the Amended and Restated Agreement of Limited Partnership in its entirety.

Acquisition of North Baja

Agreement for Purchase and Sale of Membership Interest

On July 1, 2009, we completed the acquisition of the 100% interest in North Baja Pipeline, LLC. The acquisition was made pursuant to the Agreement for Purchase and Sale of Membership Interest, dated May 19, 2009 (Acquisition Agreement), between TC PipeLines Intermediate Limited Partnership (TCILP), a subsidiary of the Partnership, and Gas Transmission Northwest Corporation (GTN), for a total purchase price of $271.4 million.

GTN is an indirect, wholly-owned subsidiary of TransCanada, which is the ultimate parent company of the General Partner of the Partnership. The purchase price of the acquisition was determined through negotiations between the GTN and the general partner on behalf of TCILP.

If GTN completes an expansion of the pipeline from the Mexico/Arizona border to Yuma City, Arizona (Yuma Lateral) by June 30, 2010, TCILP will pay GTN up to an additional $10 million for the expansion, which amount shall be determined using a formula that is based on transportation service agreements to be entered into in connection with the expansion. The Yuma Lateral project is currently under construction and is expected to be completed in March 2010. The purchase price has yet to be determined.

The acquisition was financed through a combination of debt and equity, including receipt from the general partner of approximately $1.6 million to maintain its two per cent general partner interest and the sale of limited partnership units to an affiliate as described below.

Common Unit Purchase Agreement

On July 1, 2009, we entered into a Common Unit Purchase with TransCan Northern Ltd. (TransCan Northern) to sell 2,609,680 newly issued, unregistered common units representing limited partner interests in the Partnership to TransCan Northern at a price per common unit of $30.042 for an aggregate amount of approximately $78.4 million (Offering). The Offering closed on July 1, 2009. TransCan Northern is an indirect, wholly-owned subsidiary of TransCanada.

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 $2.1 million for the year ended December 31, 2009 (2008 $2.1 million; 2007 $1.9 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.

During the second quarter of 2009, TransCanada internally announced a reorganization of its U.S. operations, which will include the relocation of some employees and equipment, and some severance costs, with certain operational cost savings to be expected in the future. According to our operating agreements, some of these costs could be borne by our pipeline systems. It is expected that the reorganization will be complete in 2010. Northern Border has entered into an amendment to their operating agreement to fix certain costs related to the reorganization.

Cash Management Programs

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.

Transportation Agreements

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to eight years. Great Lakes earned $142.4 million of transportation revenues under these contracts in 2009 (2008 $144.1 million). This amount represents 49 per cent of total revenues earned by Great Lakes in 2009 (2008 50 per cent). $66.1 million of affiliated revenue is included in the Partnership's equity income from Great Lakes in 2009 (2008 $67.0 million). At December 31, 2009, $12.9 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2008 $12.7 million).

Great Lakes has 831 MDth/d of longhaul capacity under contract expiring on October 31, 2010 with its largest shipper, TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts through October 31, 2011 for 470 MDth/d of capacity and agreed that Great Lakes would provide other transportation services. The contract for the remaining 361 MDth/d of longhaul capacity will expire October 31, 2010.

Great Lakes Rate Proceeding (RP10-149-000). In November 2009, the FERC issued an order instituting an investigation, pursuant to Section 5 of the Natural Gas Act, to determine whether the rates currently charged by Great Lakes are just and reasonable. TransCanada owns a 53.55 per cent partner interest in Great Lakes. TransCanada, Great Lakes' largest shipper, and ANR, an affiliate of Great Lakes and a shipper on Great Lakes, have filed interventions in the GL Rate Proceeding.

Other Agreements

Great Lakes, Northern Border and Tuscarora currently have interconnection, operational balancing agreement and other inter-affiliate agreements with affiliates of TransCanada. In addition, each of our pipeline systems currently have and will have in the future other routine agreements with TransCanada or one of its subsidiaries that arise in the ordinary course of business, including agreements for services and other transportation and exchange agreement and interconnection and balancing agreements with other TransCanada pipelines.

Costs charged to our pipeline systems for the years ended December 31, 2009 and 2008 by TransCanada and its affiliates and amounts payable to TransCanada and its affiliates at December 31, 2009 and 2008 are summarized in the following tables:

Year ended December 31 *(millions of dollars)*	**2009**	2008
Costs charged by TransCanada and its affiliates:		
Great Lakes	**33.8**	34.3
Northern Border[(a)]	**25.5**	30.5
North Baja[(b)]	**2.9**	4.7
Tuscarora	**3.0**	3.7
Impact on the Partnership's net income:		
Great Lakes	**14.3**	14.2
Northern Border	**12.3**	12.9
North Baja[(b)]	**2.4**	2.7
Tuscarora	**2.8**	2.7

December 31 *(millions of dollars)*	**2009**	2008
Amount payable to/(receivable from) TransCanada and its affiliates:		
Great Lakes	**6.6**	4.5
Northern Border	**2.6**	2.8
North Baja[(b)]	**(1.6)**	(2.5)
Tuscarora	**0.6**	0.8

(a) In 2008, Northern Border's costs charged by TransCanada and its affiliates include $2.0 million of charges related to Bison Pipeline LLC through the effective date of the sale.

(b) Recast as discussed in Note 2 and Note 6 to the Partnership's financial statements included elsewhere in this report.

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 Accounting Fees and Services

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

Year Ended December 31 *(dollars)*	**2009**	2008
Audit Fees[a]	**426,326**	337,393
Audit Related Fees[b]	**86,792**	12,947
Tax Fees[c]		
All Other Fees[c]		
Total	**513,118**	350,340

(a) Audit Fees include services performed related to Sarbanes-Oxley Act reporting requirements, and includes services for the statutory audit of Tuscarora.

(b) Audit related fees in 2009 related primarily to prospectus work in connection with the Partnership's November equity issuance.

(c) The Partnership has not engaged its external auditors for any tax or other services in 2009 or 2008.

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 comforts letters for documents filed with the SEC. Before our independent principal accountant is engaged each year for annual audit and other 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) and (2) Financial Statements and Financial Statement Schedules

The financial statements filed as part of this report are listed in the "Index to Financial Statements" on page F-1.

(3)

Exhibits

No.	Description
*2.1	Agreement for Purchase and Sale of Membership Interest dated May 19, 2009 by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on May 20, 2009 (File No. 000-26091)).
*3.1	Second Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated July 1, 2009 (Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009 (File No. 000-26091)).
*3.2	Certificate of Limited Partnership of TC PipeLines, LP (Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, File No. 333-69947 filed on December 30, 1998).
*10.1	Contribution, Conveyance and Assumption Agreement among TC PipeLines, LP and certain other parties dated May 28, 1999 (Exhibit 10.2 to TC PipeLines, LP's Form 10-K filed on March 28, 2000 (File No. 333-69947)).
*10.2	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company dated April 6, 2006, by and between Northern Border Intermediate Limited Partnership and TC Pipelines Intermediate Limited Partnership (Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006 (File No. 333-87753)).
*10.3	Revolving Credit Agreement, dated as of April 27, 2007, among Northern Border Pipeline Company, the lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, Wachovia Bank National Association, as Syndication Agent, BMO Capital Markets, Citibank, N.A. and Mizuho Corporate Bank, LTD., as Co-Documentation Agents, JP Morgan Chase Bank, N.A. and Export Development Canada, as Managing Agents and Wachovia Capital Markets, LLC and SunTrust Capital Markets, Inc., as Co-Lead Arrangers and Book Managers. (Exhibit 10.1 to Northern Border Pipeline Company's Form 10-Q filed on April 30, 2007 (File No. 333-88577)).
*10.3.1	First Amendment to Amended and Restated Revolving Credit Agreement dated as of July 31, 2008 between Northern Border Pipeline Company and the lenders named therein. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on November 3, 2008 (File No. 000-26091)).
*10.4	Amended and Restated Revolving Credit and Term Loan Agreement 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, dated February 13, 2007 (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.5	Subordinated Loan Agreement between TC PipeLines, LP and TransCanada PipeLines Limited, dated February 13, 2007 (Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on February 15, 2007 (File No. 000-26091)).

*10.6	Subordination and Intercreditor Agreement among TransCanada PipeLines Limited, TC PipeLines, LP, and SunTrust Bank, as Administrative Agent, dated February 13, 2007 (Exhibit 10.3 to TC PipeLines, LP's Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.7	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. (Exhibit 10.16 to Northern Border Pipeline Company's Form S-1 Registration Statement filed on July 16, 1993 (Registration No. 33-66158)).
*10.8	Form of Contribution, Conveyance and Assumption Agreement among TC PipeLines, L.P., and Northern Border Intermediate Limited Partnership. (Exhibit 10.2 to TC PipeLines, LP's Form S-1/A filed on May 3, 1999 (File No. 333-69947)).
*10.9	Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. (Exhibit 10.2 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006 (File No. 333-88577)).
*10.9.1	Amendment No.1 to Northern Border Pipeline Company Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated as of April 22, 2008. (Exhibit 10.9.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).
10.9.2	Second Amendment of Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated as of February 10, 2010.
*10.10	Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated as of December 19, 2006 (Exhibit 10.11 to TC PipeLines, LP's Form 10-K filed on March 2, 2007 (File No. 000-26091)).
*10.10.1	First Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated as of June 21, 2007. (Exhibit 10.10.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).
*10.10.2	Second Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated as of December 31, 2007. (Exhibit 10.10.2 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).
*10.10.3	Third Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated as of December 31, 2008. (Exhibit 10.10.3 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).
10.10.4	Fourth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated as of December 31, 2009.
*10.11	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. (Exhibit 10.9 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.12	Operating Agreement between Great Lakes Gas Transmission Limited Partnership and Great Lakes Gas Transmission Company, dated April 5, 1990. (Exhibit 10.10 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*#10.13	The TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), dated October 18, 2007, as amended on December 10, 2008. (Exhibit 10.25 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).

*10.14	Membership Interest Purchase Agreement as of August 28, 2008, by and between Northern Border Pipeline Company and TransCanada Pipeline USA Ltd. (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on November 3, 2008 (File No. 000-26091)).
*10.15	Interconnect Agreement between ANR Pipeline Company and Northern Border Pipeline Company, dated June 9, 2008. (Exhibit 10.3 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008 (File No. 000-26091)).
*10.16	Common Unit Purchase Agreement dated July 1, 2009 by and between TC PipeLines, LP and TransCan Northern Ltd. (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009 (File No. 000-26091)).
*10.17	Management Services Agreement dated January 1, 2002 by and between Gas Transmission Service Company, LLC (formally PG&E Gas Transmission Service Company, LLC) and North Baja Pipeline, LLC. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 4, 2009 (File No. 000-26091)).
*10.18	Exchange Agreement, dated July 1, 2009, by and between TC PipeLines, LP and TC PipeLines GP, Inc. (Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on July 1, 2009 (File No. 000-26091)).
21.1	Subsidiaries of the Registrant.
23.1	Consent of KPMG LLP with respect to the financial statements of TC PipeLines, LP
23.2	Consent of KPMG LLP with respect to the financial statements of 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 balance sheets of TC PipeLines GP, Inc.
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	Consolidated Balance Sheets of TC PipeLines GP, Inc. as of December 31, 2009 and 2008.
*99.2	Transportation Service Agreement FT4761 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*99.3	Transportation Service Agreement FT5840 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 1, 2005. (Exhibit 10.6 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*99.4	Transportation Service Agreement FT 8742 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 6, 2007. (Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 28, 2008 (File No. 000-26091)).
*99.5	Transportation Service Agreement FT9141 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 12, 2008. (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008 (File No. 000-26091)).
*99.6	Transportation Service Agreement FT9158 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 14, 2008. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008 (File No. 000-26091)).

*99.7	Transportation Service Agreement FT11701 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 26, 2008. (Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).
*99.8	Transportation Service Agreement FT4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 26, 2008. (Exhibit 10.22 to TC PipeLines, LP's Form 10-K filed on February 27, 2009 (File No. 000-26091)).
*99.9	Market Center Service Agreement MC11987 between Great Lakes Gas Transmission Limited Partnership and TransCanada Gas Storage USA Inc., dated February 27, 2009. (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 30, 2009 (File No. 000-26091)).
*99.10	Transportation Service Agreement IT11986 between Great Lakes Gas Transmission Limited Partnership and TransCanada Gas Storage USA Inc., dated February 27, 2009. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2009 (File No. 000-26091)).
99.11	Transportation Service Agreement FT4760 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009.
99.12	Transportation Service Agreement FT4761 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009.
99.13	Transportation Service Agreement FT14131 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009.
99.14	Transportation Service Agreement FT14132 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009.

*
Indicates exhibits incorporated by reference.

+
Pursuant to item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

#
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 26th day of February 2010.

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

By: /s/ RUSSELL K. GIRLING

Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ ROBERT C. JACOBUCCI

Robert C. Jacobucci
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/ RUSSELL K. GIRLING Russell K. Girling	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2010
/s/ ROBERT C. JACOBUCCI Robert C. Jacobucci	Controller and Principal Financial Officer	February 26, 2010
/s/ GREGORY A. LOHNES Gregory A. Lohnes	Director	February 26, 2010
/s/ KRISTINE L. DELKUS Kristine L. Delkus	Director	February 26, 2010
/s/ STEVEN D. BECKER Steven D. Becker	Director	February 26, 2010
/s/ WALENTIN (VAL) MIROSH Walentin (Val) Mirosh	Director	February 26, 2010
/s/ JACK F. JENKINS-STARK Jack F. Jenkins-Stark	Director	February 26, 2010
/s/ DAVID L. MARSHALL	Director	February 26, 2010

Signature	Title	Date
David L. Marshall		

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of 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, 2009 and 2008, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners' equity for each of the years in the three-year period ended December 31, 2009. We also have audited TC PipeLines, LP internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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 Controls 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.

An entity'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. An entity'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, 2009 and 2008, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009, 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, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Calgary, Canada
February 24, 2010

TC PIPELINES, LP

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2009**	**2008**[(a)]
Assets		
Current Assets		
Cash and cash equivalents	**3.1**	8.4
Accounts receivable and other (Note 17)	**8.6**	11.4
	11.7	19.8
Investment in Great Lakes (Note 3)	**691.2**	704.5
Investment in Northern Border (Note 4)	**523.0**	514.8
Plant, property and equipment (Note 5)	**318.0**	330.3
Goodwill	**130.2**	130.2
Other assets	**1.0**	1.5
	1,675.1	1,701.1
Liabilities and Partners' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**4.5**	5.3
Accrued interest	**1.3**	3.7
Current portion of long-term debt (Note 7)	**53.4**	4.4
Current portion of fair value of derivative contracts (Note 16)	**12.9**	11.8
	72.1	25.2
Long-term debt (Note 7)	**487.9**	532.4
Fair value of derivative contracts and other (Note 16)	**11.6**	20.4
	571.6	578.0
Due to North Baja's former parent		247.5
Partners' Equity (Note 8)		
Common units	**1,105.6**	891.4
General partner	**23.6**	19.1
Accumulated other comprehensive loss	**(25.7)**	(34.9)
	1,103.5	875.6
	1,675.1	1,701.1

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

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)	2009[(a)]	2008[(a)]	2007[(a)]
Equity income from investment in Great Lakes (Note 3)	**59.1**	57.3	49.0
Equity income from investment in Northern Border (Note 4)	**40.3**	65.3	61.2
Transmission revenues	**67.9**	64.5	49.8
Operating expenses	**(11.0)**	(11.5)	(10.8)
General and administrative	**(6.2)**	(4.1)	(3.4)
Depreciation (Note 5)	**(14.7)**	(13.9)	(12.4)
Financial charges, net and other (Note 9)	**(29.3)**	(34.6)	(38.7)
Net income	**106.1**	123.0	94.7
Net income allocation (Note 10)			
Common units	**90.6**	95.1	80.0
General partner	**7.2**	12.6	9.0
	97.8	107.7	89.0
Net income per common unit (Note 10)	**$2.34**	$2.73	$2.48
Weighted average common units outstanding *(millions)*	**38.7**	34.9	32.3
Common units outstanding, end of the period *(millions)*	**46.2**	34.9	34.9

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	2009	2008	2007
Net income[(a)]	**106.1**	123.0	94.7
Other comprehensive income/(loss)			
Change associated with current period hedging transactions (Note 16)	**7.9**	(22.0)	(11.4)
Change associated with current period hedging transactions of investees	**1.3**	(1.6)	(1.7)
	9.2	(23.6)	(13.1)
Total comprehensive income	**115.3**	99.4	81.6

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

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	2009[(a)]	2008[(a)]	2007[(a)]
Cash Generated From Operations			
Net income	106.1	123.0	94.7
Depreciation (Note 5)	14.7	13.9	12.4
Amortization of other assets (Note 9)	0.4	0.5	0.4
Non-controlling interests			0.2
Increase in other long-term liabilities	0.2	0.1	
Equity allowance for funds used during construction	(0.5)	(1.1)	(1.1)
Decrease/(increase) in operating working capital (Note 12)	2.5	(4.2)	1.7
	123.4	132.2	108.3
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Great Lakes	13.4	16.6	12.3
Northern Border	35.4	25.4	25.1
Investment in Great Lakes (Note 3)	(0.1)		(733.0)
Investment in Northern Border (Notes 4 and 15)	(42.3)		(7.5)
Investment in North Baja, net of cash acquired (Note 6)	(271.4)		
Investment in Tuscarora, net of cash acquired			(3.9)
Capital expenditures	(1.9)	(34.6)	(26.1)
Other assets	0.1		(1.1)
(Increase)/decrease in investing working capital (Note 12)	(2.9)	(3.7)	4.0
	(269.7)	3.7	(730.2)
Financing Activities			
Distributions paid (Note 11)	(117.0)	(108.6)	(86.7)
Equity issuances, net	265.6		607.0
Long-term debt issued (Note 7)	208.0	4.0	171.5
Long-term debt repaid (Note 7)	(203.5)	(40.6)	(66.2)
Due to North Baja's former parent (Note 6)	(12.1)	10.2	(0.4)
	141.0	(135.0)	625.2
(Decrease)/increase in cash and cash equivalents	(5.3)	0.9	3.3
Cash and cash equivalents, beginning of year	8.4	7.5	4.2
Cash and cash equivalents, end of year	3.1	8.4	7.5
Interest payments made	16.5	30.3	41.3

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

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

	Common Units		General Partner	Accumulated Other Comprehensive Loss[(a)]	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, 2006	17.5	295.6	6.5	1.8	17.5	303.9
Net income[(b)]		86.9	7.8			94.7
Net income attributed to former North Baja owner		(5.6)	(0.1)			(5.7)
Equity issuances, net	17.4	594.4	12.6		17.4	607.0
Distributions paid		(79.0)	(7.7)			(86.7)
Other comprehensive loss				(13.1)		(13.1)
Partners' equity at December 31, 2007	34.9	892.3	19.1	(11.3)	34.9	900.1
Net income[(b)]		110.9	12.1			123.0
Net income attributed to former North Baja owner		(15.0)	(0.3)			(15.3)
Distributions paid		(96.8)	(11.8)			(108.6)
Other comprehensive loss				(23.6)		(23.6)
Partners' equity at December 31, 2008	34.9	891.4	19.1	(34.9)	34.9	875.6
Net income[(b)]		98.8	7.3			106.1
Net income attributed to former North Baja owner		(8.2)	(0.1)			(8.3)
Equity issuances, net (Notes 6 and 8)	11.3	260.2	5.4		11.3	265.6
Distributions paid		(109.4)	(7.6)			(117.0)
Excess purchase price over net acquired assets[(c)]		(27.2)	(0.5)			(27.7)
Other comprehensive loss				9.2		9.2
Partners' equity at December 31, 2009	**46.2**	**1,105.6**	**23.6**	**(25.7)**	**46.2**	**1,103.5**

(a) The Partnership uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at December 31, 2009, the amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in the next 12 months is $13.0 million, which will be offset by a reduction to interest expense of a similar amount.

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

(c) Accounting adjustment for common control transaction. See Note 6 for details.

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 (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 per cent 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 per cent general partner interest in Northern Border Pipeline Company (Northern Border), a Texas general partnership. Northern Border owns a 1,249-mile U.S. interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to markets in the Midwestern U.S.;

- a 100 per cent interest in North Baja Pipeline, LLC (North Baja), a Delaware limited liability company. North Baja owns an 80-mile U.S. interstate pipeline system that transports natural gas between an interconnection with El Paso Natural Gas Company near Ehrenberg, Arizona and an interconnection near Ogilby, California on the California/Mexico border with the Gasoducto Bajanorte natural gas pipeline system; and

- a 100 per cent interest in Tuscarora Gas Transmission Company (Tuscarora), a Nevada general partnership. Tuscarora owns a 240-mile U.S. interstate pipeline system that transports natural gas from Oregon, where it interconnects with facilities of Gas Transmission Northwest Corporation, a wholly-owned subsidiary of TransCanada, to a terminus in Northern Nevada.

The Partnership is managed by its general partner, TC PipeLines GP, Inc. (TC PipeLines GP), a wholly-owned subsidiary of TransCanada. The general partner provides administrative services for the Partnership and is reimbursed for its costs and expenses. In addition to its aggregate two per cent general partner interest in the Partnership, the general partner owns 5,797,106 common units, representing an effective 14.3 per cent interest in the Partnership at December 31, 2009. TransCanada also indirectly holds 11,287,725 common units representing an effective 23.9 per cent limited partner interest in the Partnership at December 31, 2009.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The accompanying financial statements and related notes present the financial position of the Partnership as of December 31, 2009 and 2008 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2009, 2008 and 2007. The Partnership uses the equity method of accounting for its investments in Great Lakes and Northern Border, over which it is able to exercise significant influence. The Partnership consolidates its investments in North Baja and Tuscarora.

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja from TransCanada. The acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of 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. Refer to Note 6 for additional disclosure regarding the North Baja acquisition.

Amounts are stated in U.S. dollars. Certain comparative figures have been reclassified to conform to the current year's presentation.

(b) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at 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 is 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 25 to 30 years. Metering and other is depreciated on a straight-line basis over the estimated useful lives of the equipment, which range from 3 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.

The Partnership assesses its long-lived assets for impairment based on *Accounting Standards Codification (ASC) 360-10-35 Property, Plant, and Equipment Overall Subsequent Measurement.* A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed the undiscounted cash flows expected to be generated by the asset. If the carrying amount exceeds the undiscounted cash flows, impairment is recognized to the extent the carrying amount exceeds its fair value.

(e) Partners' Equity

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

(f) Revenue Recognition

Transmission revenues relate to North Baja and Tuscarora, 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, 2009, 2008 and 2007, the Partnership has not recognized any transmission revenue that is subject to refund.

(g) 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.

(h) Acquisitions and Goodwill

The Partnership accounts for business acquisitions from third parties using the purchase 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 for accounting purposes; however, it is tested on an annual basis for impairment, or more frequently if any indicators of impairment are evident.

The Partnership accounts for business acquisitions between entities under common control using a method similar to a pooling of interests, 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.

(i) Derivative Financial Instruments and Hedging Activities

The Partnership utilizes derivative and other financial instruments to manage its exposure to changes in interest rates. Derivatives and other hedging instruments must be designated as hedges and be effective to qualify for hedge accounting. For cash flow hedges, unrealized gains or losses relating to derivatives are recognized as other comprehensive income. In the event that a derivative does not meet the designation or effectiveness criteria, any unrealized gain or loss on the instrument is recognized immediately in earnings.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related gains or losses are immediately recognized in earnings and amounts previously recognized in other comprehensive income are reclassified to earnings prospectively. Costs associated with the purchase of certain hedging instruments are deferred and amortized against interest expense.

(j) Asset Retirement Obligation

ASC 410 Asset Retirement and Environmental Obligations provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized 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 long-lived assets included within the scope of ASC 410 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.

No amount is recorded for asset retirement obligations relating to the assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements.

(k) Government Regulation

North Baja and Tuscarora, the Partnership's wholly-owned pipeline systems, are subject to regulation by the FERC. The Partnership's accounting policies conform to *ASC 980 Regulated Operations.* Accordingly, 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 ASC 980, considering such factors as regulatory changes, the impact of competition, and the ability to recover regulatory assets. As of December 31, 2009 and 2008, the Partnership has no regulatory assets or liabilities, other than the allowance for funds used during construction that is capitalized and included in plant, property and equipment.

(l) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective interest rate method over the term of the related debt.

NOTE 3 INVESTMENT IN GREAT LAKES

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent interest concurrent with the Partnership's acquisition of its interest. On the same day, a wholly-owned subsidiary of TransCanada acquired 100 per cent ownership of the operator of Great Lakes. Great Lakes is regulated by the FERC and its accounting policies conform to *ASC 980 Regulated Operations.*

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 per cent limited partnership interest in TC GL Intermediate Limited Partnership.

On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 (November 2009 Order) instituting an investigation, pursuant to Section 5 of the Natural Gas Act (GL Rate Proceeding). The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed Great Lakes actual cost of service and therefore may be unjust and unreasonable. On February 4, 2010, Great Lakes filed a cost and revenue study (GL Cost and Revenue Study) in response to the November 2009 Order. The GL Cost and Revenue Study supports Great Lakes' current rates and shows that if Great Lakes filed to reset its rates, these rates should be above Great Lakes' current rates. The GL Cost and Revenue Study reflects the increased risk of de-contracting on the Great Lakes system which may result in decreases to overall long-term, daily and short-term firm transportation revenues, and interruptible transportation revenues, as compared to prior periods.

In the absence of a settlement, a hearing in the GL Rate Proceeding is scheduled for early August 2010 and an initial decision by the Administrative Law Judge is expected in November 2010. Should the FERC determine as a result of these proceedings, that Great Lakes' rates are not just and reasonable; the FERC could order Great Lakes to reduce its rates prospectively. Great Lakes' has expressed interest in pursuing settlement discussions with the FERC and interveners with the aim of bringing certainty to Great Lakes rates.

The Partnership uses the equity method of accounting for its investment in Great Lakes. The Partnership's equity income from its investment in Great Lakes amounted to $59.1 million for the year ended December 31, 2009 (2008 $57.3 million; $49.0 million for the period February 23, 2007 to December 31, 2007). Great Lakes had no undistributed earnings for the years ended December 31, 2009 and 2008, and the period February 23, 2007 to December 31, 2007.

The following tables contain summarized financial information of Great Lakes as at December 31, 2009 and 2008 and for the years ended December 31, 2009 and 2008, and for the period February 23, 2007 to December 31, 2007:

Summarized Consolidated Great Lakes Balance Sheet

December 31 (millions of dollars)	**2009**	**2008**
Assets		
Cash and cash equivalents	**0.1**	1.6
Other current assets	**83.0**	80.2
Plant, property and equipment, net	**873.3**	923.4
	956.4	1,005.2
Liabilities and Partners' Equity		
Current liabilities	**40.3**	43.0
Deferred credits	**3.8**	2.3
Long-term debt, including current maturities	**411.0**	430.0
Partners' capital	**501.3**	529.9
	956.4	1,005.2

Summarized Consolidated Great Lakes Income Statement			**For the period February 23 to December 31,**
Year ended December 31 (millions of dollars)	**2009**	**2008**	**2007**
Transmission revenues	**289.7**	287.1	236.2
Operating expenses	**(66.5)**	(67.1)	(53.7)
Depreciation	**(58.5)**	(58.5)	(49.4)
Financial charges, net and other	**(31.9)**	(32.6)	(27.6)
Michigan business tax	**(5.4)**	(5.5)	
Net income	**127.4**	123.4	105.5

NOTE 4 INVESTMENT IN NORTHERN BORDER

The Partnership owns a 50 per cent general partner interest in Northern Border. The other 50 per cent partnership interest in Northern Border is held by ONEOK Partners, L.P., a publicly traded limited partnership. Northern Border is regulated by the FERC and its accounting policies conform to *ASC 980 Regulated Operations.* Northern Border is operated by TransCanada.

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 per cent limited partnership interest in TC PipeLines Intermediate Limited Partnership.

The Partnership uses the equity method of accounting for its investment in Northern Border. The Partnership's equity income from its investment in Northern Border amounted to $40.3 million for the year ended December 31, 2009 (2008 $65.3 million; 2007 $61.2 million). Equity income from Northern Border includes a twelve-year amortization of a $10.0 million transaction fee paid to the operator of Northern Border as an inducement to become operator at the time of the additional 20 per cent acquisition in April 2006. Northern Border had no undistributed earnings for the years ended December 31, 2009, 2008 and 2007.

On February 2, 2009, Northern Border received a Notice of Violation (NOV) from the United States Environmental Protection Agency alleging that Northern Border was in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on its system. Northern Border disputes the NOV. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty, but does not expect such amounts to be material to its financial condition.

The following tables contain summarized financial information of Northern Border as at December 31, 2009 and 2008 and for the years ended December 31, 2009, 2008 and 2007:

Summarized Northern Border Balance Sheet

December 31 (millions of dollars)	**2009**	**2008**
Assets		
Cash and cash equivalents	**16.9**	21.6
Other current assets	**30.2**	39.1
Plant, property and equipment, net	**1,343.1**	1,390.8
Other assets	**24.2**	24.5
	1,414.4	1,476.0
Liabilities and Partners' Equity		
Current liabilities	**38.0**	48.7
Deferred credits and other	**8.3**	11.2
Long-term debt, including current maturities	**564.6**	630.4
Partners' equity		
Partners' capital	**806.6**	791.4
Accumulated other comprehensive loss	**(3.1)**	(5.7)
	1,414.4	1,476.0

Summarized Northern Border Income Statement

Year ended December 31 (millions of dollars)	**2009**	**2008**	**2007**
Transmission revenues	**249.2**	293.1	309.4
Operating expenses	**(70.8)**	(78.0)	(83.5)
Depreciation	**(61.9)**	(61.1)	(60.7)
Financial charges, net and other (Note 13)	**(34.4)**	(21.8)	(41.1)
Net income	**82.1**	132.2	124.1

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2009			**2008**		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Pipeline	**279.6**	**90.7**	**188.9**	279.5	81.3	198.2
Compression	**113.4**	**20.5**	**92.9**	112.8	16.4	96.4
Metering and other	**37.5**	**7.1**	**30.4**	37.1	5.9	31.2
Under construction	**5.8**		**5.8**	4.5		4.5
	436.3	**118.3**	**318.0**	433.9	103.6	330.3

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

NOTE 6 ACQUISITIONS AND REVISED INCENTIVE DISTRIBUTION RIGHTS

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja, a Delaware limited liability company, from TransCanada. The North Baja pipeline system extends from an interconnection with El Paso Natural Gas Company near Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border where it connects with the Gasoducto Bajanorte natural gas pipeline system owned by Sempra Energy International. North Baja is regulated by the FERC and is operated by TransCanada.

The purchase price of $271.4 million was financed through a combination of (i) a draw of $170.0 million on the Partnership's $250.0 million revolving portion of its revolving credit and term loan agreement (Senior Credit Facility), (ii) issuance of 2,609,680 common units at $30.042 per common unit to TransCanada for gross proceeds of $78.4 million, (iii) issuance of additional general partner interest to the general partner of $1.6 million, which was required to maintain the general partner's two per cent general partner interest in the Partnership, and (iv) approximately $21.4 million of cash on hand.

The acquisition of North Baja was accounted for as a transaction between entities under common control, similar to a pooling of interests, 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. The purchase price was recorded as follows: Working capital of $2.0 million; Plant, property and equipment of $193.5 million; Goodwill of $48.5 million; Other assets of $0.1 million; and Other long-term liabilities of $0.4 million. As the fair value paid for North Baja was greater than the recorded net assets of North Baja, the excess purchase price paid of $27.7 million was recorded as a reduction to Partners' Equity. The effect of recasting the Partnership's consolidated financial statements to account for the common control transaction increased the Partnership's net income by $15.3 million and $5.7 million for the years ended December 31, 2008 and 2007, respectively, from amounts previously reported. In addition, the Partnership's 2009 net income increased by $8.3 million due to the recasting of its results for the six months ended June 30, 2009.

The Partnership agreed to acquire an expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona for an additional sum up to $10.0 million, if TransCanada completed the expansion by June 30, 2010. The expansion is currently under construction and is expected to be completed in March 2010. The purchase price has yet to be determined. This acquisition will be accounted for when the transaction occurs.

Concurrent with the acquisition of North Baja, the Partnership entered into an exchange agreement with its general partner whereby the Partnership issued 3,762,000 common units to the general partner and provided for revised incentive distribution rights (Revised IDRs) in exchange for the cancellation of the incentive distribution rights available to the general partner (Old IDRs) under the Amended and Restated Agreement of Limited Partnership of the Partnership.

Under the terms of the Revised IDRs, the distributions to the general partner were reset to two per cent, down from the general partner distribution levels of the Old IDRs at 50 per cent (for combined general partner interest and incentive distribution interest). The incentive distribution levels of the Revised IDRs will result in increased combined distributions to the general partner (for general partner interest and incentive distribution interest) of 15 per cent and a maximum of 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit or $3.24 and $3.52 per common unit on an annualized basis, respectively.

NOTE 7 CREDIT FACILITIES AND LONG-TERM DEBT

December 31 (millions of dollars)	**2009**	**2008**
Senior Credit Facility due 2011	**484.0**	475.0
7.13% Series A Senior Notes due 2010	**48.2**	51.3
7.99% Series B Senior Notes due 2010	**4.4**	5.0
6.89% Series C Senior Notes due 2012	**4.7**	5.5
	541.3	536.8

The Partnership's Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility with a banking syndicate. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. In 2009, none of the senior term loan was repaid (2008 $13.0 million); therefore, $475.0 million remained outstanding under the senior term loan at December 31, 2009. $9.0 million was outstanding under the revolving portion of the Senior Credit Facility at December 31, 2009 (2008 $nil), leaving $241.0 million available for future borrowings.

The Senior Credit Facility matures on December 12, 2011, subject to two one-year extensions at the option of the Partnership and with the approval of a majority of the lenders thereunder. Amounts borrowed may be repaid in part, or in full, prior to that time without penalty. Borrowings under the Senior Credit Facility bear interest based, at the Partnership's election, on the London Interbank Offered Rate (LIBOR) or the prime rate plus, in either case, an applicable margin. There was $484.0 million outstanding under the Senior Credit Facility at December 31, 2009 (2008 $475.0 million). The interest rate on the Senior Credit Facility averaged 1.42 per cent for the year ended

December 31, 2009 (2008 3.75 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.10 per cent for the year ended December 31, 2009 (2008 5.15 per cent). Prior to hedging activities, the interest rate was 0.97 per cent at December 31, 2009 (2008 2.67 per cent). At December 31, 2009, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

Series A, B and C 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. On December 21, 2010, the Series A and B Senior Notes will mature. As market conditions dictate, the Partnership intends to refinance this debt with either fixed-rate or variable-rate debt.

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

(millions of dollars)	
2010	53.4
2011	484.8
2012	3.1
	541.3

NOTE 8 PARTNERS' EQUITY

On November 18, 2009, the Partnership completed a public offering of 5,000,000 common units at $38.00 per common unit for gross proceeds of $190.0 million and net proceeds of $181.8 million after unit issuance costs. TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $3.8 million to the Partnership in connection with the offering.

Refer to Note 6 for disclosure regarding the equity issuance in connection with the acquisition of North Baja.

At December 31, 2009, Partners' equity includes 46,227,766 common units (2008 34,856,086 common units) representing an aggregate 98 per cent 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 per cent general partner interest. In aggregate, the general partner's interests represent an effective 14.3 per cent ownership in the Partnership at December 31, 2009 (December 31, 2008 7.7 per cent).

NOTE 9 FINANCIAL CHARGES, NET AND OTHER

Year ended December 31 (millions of dollars)	**2009**	**2008**	**2007**
Interest expense on long-term debt	**11.9**	23.1	35.1
Interest expense on short-term debt[a]	**2.7**	6.3	7.7
Capitalized interest[a]	**(0.4)**	(1.4)	(1.6)
Loss/(gain) on interest rate swaps and options	**15.1**	6.9	(1.4)
Interest income[a]	**(0.4)**	(0.8)	(2.0)
Amortization of other assets	**0.4**	0.5	0.4
Other			0.5
	29.3	34.6	38.7

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

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 two per cent interest, plus an amount equal to incentive distributions. Incentive distributions are received by 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)	2009	2008	2007
Net income[(a)]	106.1	123.0	94.7
North Baja's contribution prior to acquisition	(8.3)	(15.3)	(5.7)
Net income allocated to partners[(b)]	97.8	107.7	89.0
Net income allocated to general partner:			
General partner interest	(1.9)	(2.2)	(1.8)
Incentive distribution income allocation	(5.3)	(10.4)	(7.2)
	(7.2)	(12.6)	(9.0)
Net income allocable to common units	90.6	95.1	80.0
Weighted average common units outstanding *(millions)*	38.7	34.9	32.3
Net income per common unit	$2.34	$2.73	$2.48

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

(b) Net income allocated to partners excludes North Baja's earnings prior to the Partnership's acquisition of North Baja on July 1, 2009, as the earnings of North Baja prior to that date were allocated to TransCanada and were not allocable to either the general partner or common units.

Effective January 1, 2009, the Partnership adopted the provisions of *ASC 260-10-55 Earnings Per Share Overall Implementation Guidance and Illustrations Master Limited Partnerships*. According to the new standard, for purposes of calculating net income per common unit, net income must be reduced by the amount of available cash that will be distributed with respect to that period. Any undistributed income must be allocated to the various interest holders based on the contractual provisions of the partnership agreement. Under the partnership agreement, for any quarterly period, the participation of the Incentive Distributions Rights (IDRs) is limited to available cash distributions declared. Accordingly, the undistributed net income has been allocated to the general partner's two per cent interest and the common unitholders.

The retrospective application of ASC 260-10-55 impacted the amount of net income allocated to the IDR holder for the years ended December 31, 2008 and 2007, as the amount previously allocated to the IDR holder was based on the cash distribution paid in that year and is now based on the amount declared for the year. The retrospective application of this standard resulted in a reduction from $2.75 to $2.73 in net income per common unit for the year ended December 31, 2008 (2007 reduction from $2.51 to $2.48 in net income per common unit).

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 $0.73 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. Prior to July 1, 2009, the combined general partner interest and incentive distribution interest payable to the General Partner were 15 per cent, 25 per cent, and 50 per cent of all quarterly distributions of Available Cash that exceed target levels of $0.45, $0.5275 and $0.69 per common unit, respectively. On July 1, 2009, the incentive distributions were revised under the Second Amended and Restated Agreement of Limited Partnership of the Partnership. Currently, the combined general partner interest and incentive distribution interest payable to the General Partner are 15 per cent and a maximum of 25 per cent 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, 2009, the Partnership distributed $2.87 per common unit (2008 $2.775 per common unit; 2007 $2.565 per common unit). The distributions paid for the year ended December 31, 2009 included incentive distributions to the general partner in the amount of $5.3 million (2008 $9.7 million; 2007 $5.9 million). 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 per cent to the general partner.

NOTE 12 CHANGE IN WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2009[(a)]**	**2008[(a)]**	**2007[(a)]**
Decrease/(increase) in accounts receivable and other	**2.8**	(0.6)	(2.1)
(Decrease)/increase in bank indebtedness		(1.4)	1.4
(Decrease)/increase in accounts payable and accrued liabilities	**(0.8)**	(5.0)	4.8
(Decrease)/increase in accrued interest	**(2.4)**	(0.9)	1.6
	(0.4)	(7.9)	5.7
(Increase)/decrease in investing working capital	**(2.9)**	(3.7)	4.0
Decrease/(increase) in operating working capital	**2.5**	(4.2)	1.7

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

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 $2.1 million for the year ended December 31, 2009 (2008 $2.1 million; 2007 $1.9 million).

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

Costs charged to our pipeline systems for the years ended December 31, 2009 and 2008 by TransCanada and its affiliates and amounts payable to TransCanada and its affiliates at December 31, 2009 and 2008 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2009**	**2008**
Costs charged by TransCanada and its affiliates:		
Great Lakes	**33.8**	34.3
Northern Border[(a)]	**25.5**	30.5
North Baja[(b)]	**2.9**	4.7
Tuscarora	**3.0**	3.7
Impact on the Partnership's net income:		
Great Lakes	**14.3**	14.2
Northern Border	**12.3**	12.9
North Baja[(b)]	**2.4**	2.7
Tuscarora	**2.8**	2.7

December 31 (millions of dollars)	**2009**	**2008**
Amount payable to/(receivable from) TransCanada and its affiliates:		
Great Lakes	**6.6**	4.5
Northern Border	**2.6**	2.8
North Baja[(b)]	**(1.6)**	(2.5)
Tuscarora	**0.6**	0.8

(a) In 2008, Northern Border's costs charged by TransCanada and its affiliates include $2.0 million of charges related to Bison Pipeline LLC through the effective date of the sale.

(b)

Recast as discussed in Note 2 and Note 6.

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to eight years. Great Lakes earned $142.4 million of transportation revenues under these contracts in 2009 (2008 $144.1 million). This amount represents 49 per cent of total revenues earned by Great Lakes in 2009 (2008 50 per cent). $66.1 million of affiliated revenue is included in the Partnership's equity income from Great Lakes in 2009 (2008 $67.0 million). At December 31, 2009, $12.9 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2008 $12.7 million).

Great Lakes has 831 thousand dekatherms per day (MDth/d) of longhaul capacity under contract expiring on October 31, 2010 with its largest shipper, TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts through October 31, 2011 for 470 MDth/d of capacity and agreed that Great Lakes would provide other transportation services. The contract for the remaining 361 MDth/d of longhaul capacity will expire October 31, 2010.

In August 2008, Northern Border sold its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada for $20.0 million. In connection with this transaction, Northern Border recorded a gain on sale of $16.2 million, of which the Partnership's share is $8.1 million. In the Summarized Northern Border Income Statement provided in Note 4, the gain on sale is included in Financial charges, net and other.

Northern Border's Des Plaines Project consists of the construction, ownership and operation of interconnect facilities near Joliet, Illinois. In June 2008, in connection with the Des Plaines Project, Northern Border and ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada, entered into an Interconnect Agreement, which provided that Northern Border would reimburse ANR for the cost of the interconnect facilities to be owned by ANR. In June 2008, Northern Border paid ANR $0.5 million.

NOTE 14 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected financial data for the four quarters in 2009 and 2008:

Quarter ended (millions of dollars except per unit amounts)	Mar 31	Jun 30	Sep 30	Dec 31
2009				
Equity income	**35.1**	**18.3**	**23.7**	**22.3**
Transmission revenues[a]	**16.8**	**16.8**	**17.5**	**16.8**
Net income[a]	**35.9**	**17.9**	**27.4**	**24.9**
Net income per common unit	**$0.82**	**$0.31**	**$0.65**	**$0.56**
Cash distributions paid	**27.7**	**27.8**	**30.8**	**30.7**
2008				
Equity income	38.1	22.5	31.9	30.1
Transmission revenues[a]	14.1	16.1	17.4	16.9
Net income[a]	37.3	23.6	33.0	29.1
Net income per common unit	$0.87	$0.47	$0.72	$0.67
Cash distributions paid	25.6	27.4	27.8	27.8

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

NOTE 15 CAPITAL REQUIREMENTS

In the first quarter of 2009, the Partnership made an equity contribution of $4.3 million to Northern Border, representing the Partnership's 50 per cent share of an $8.6 million cash call issued by Northern Border to complete the Des Plaines Project. In the third quarter of 2009, the Partnership made an equity contribution of $38.0 million, representing the Partnership's 50 per cent share of a $76.0 million cash call issued by Northern Border to partially fund the repayment of $200.0 million of debt which matured on September 1, 2009.

NOTE 16 DERIVATIVE 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 carry 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, 2009 and 2008 are as follows:

	2009		2008	
December 31 (millions of dollars)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Senior Credit Facility	**484.0**	**484.0**	475.0	475.0
Series A Senior Notes	**48.2**	**50.8**	51.3	52.3
Series B Senior Notes	**4.4**	**4.7**	5.0	5.2
Series C Senior Notes	**4.7**	**5.2**	5.5	5.4
	541.3	**544.7**	536.8	537.9

The Partnership's long-term debt results in exposures to changing interest rates. The Partnership uses derivatives to assist in managing its exposure to interest rate risk.

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at December 31, 2009 (2008 $475.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid is 3.86 per cent. $100.0 million of variable-rate debt was hedged by an interest rate option through May 22, 2009 at an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

Under *ASC 820 Fair Value Measurements and Disclosures,* 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 where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At December 31, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $23.8 million (2008 negative $31.7 million), of which $12.9 million is classified as a current liability (2008 $11.8 million). The fair value of the interest rate swaps was calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. In 2009, the Partnership recorded interest expense of $15.1 million on the interest rate swaps and options (2008 $6.9 million).

NOTE 17 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2009**	**2008**[(a)]
Accounts receivable	**7.4**	9.0
Inventory	**0.6**	0.6
Prepayments	**0.5**	0.5
Other assets	**0.1**	1.3
	8.6	11.4

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

NOTE 18 SUBSEQUENT EVENTS

On January 19, 2010, the Board of Directors of the general partner declared the Partnership's fourth quarter 2009 cash distribution in the amount of $0.73 per common unit. The fourth quarter cash distribution which was paid on February 12, 2010 to unitholders of record as of January 31, 2010, totaled $34.4 million and was paid in the following manner: $33.7 million to common unitholders (including $4.2 million to the general partner as holder of 5,797,106 common units and $8.2 million to TransCanada as holder of 11,287,725 common units) and $0.7 million to the general partner in respect of its two per cent general partner interest. The cash distribution represents an annual cash distribution of $2.92 per common unit.

Great Lakes declared and paid its fourth quarter 2009 distribution of $33.7 million on February 1, 2010, of which the Partnership received its 46.45 per cent share or $15.7 million.

Northern Border declared and paid its fourth quarter 2009 distribution of $32.8 million on February 1, 2010, of which the Partnership received its 50 per cent share or $16.4 million.

The Partnership has evaluated subsequent events from January 1, 2010 through February 24, 2010, which represents the date the financial statements were issued.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary (the Partnership) as of December 31, 2009 and 2008, and the related consolidated statements of income and partners' capital, and cash flows for the each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2009 and 2008, and the results of their operations and their cash flows for the each of the years in the three-year period ended December 31, 2009 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 11, 2010

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF INCOME AND PARTNERS' CAPITAL

Years Ended December 31 (Thousands of Dollars)	**2009**	2008	2007
Transportation Revenues			
Affiliated Revenues	**$ 142,364**	144,137	137,166
Nonaffiliated Revenues	**147,329**	142,993	145,660
	289,693	287,130	282,826
Operating Expenses			
Operation and Maintenance	**48,760**	46,276	42,125
Depreciation	**58,503**	58,522	58,046
Property and Other Non Income Taxes	**17,729**	20,788	22,195
	124,992	125,586	122,366
Operating Income	**164,701**	161,544	160,460
Other Income (Expense)			
Interest on Long Term Debt	**(32,884)**	(34,222)	(35,096)
Interest Income	**495**	1,299	2,872
Other, Net	**517**	318	65
	(31,872)	(32,605)	(32,159)
Income Before Partnership Income Taxes	**$ 132,829**	128,939	128,301
Income Tax Expense	**(5,417)**	(5,503)	
Net Income	**$ 127,412**	123,436	128,301
Partners' Capital			
Balance at Beginning of Year	**$ 529,886**	565,650	630,849
Net Income	**127,412**	123,436	128,301
Distributions to Partners	**(156,000)**	(159,200)	(193,500)
Balance at End of Year	**$ 501,298**	529,886	565,650

See accompanying notes to consolidated financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED BALANCE SHEETS

As of December 31 (Thousands of Dollars)	**2009**	2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 125**	1,637
Demand Loan Receivable from Affiliate	**33,974**	25,467
Accounts Receivable (Net of allowance of $250 in 2009 and 2008)	**22,980**	26,938
Receivable from Affiliates	**12,922**	12,739
Materials and Supplies	**10,235**	10,307
Prepayments	**2,856**	4,775
	83,092	81,863
Gas Utility Plant		
Property, Plant, and Equipment	**2,054,308**	2,049,160
Less Accumulated Depreciation	**(1,181,042)**	(1,125,779)
	873,266	923,381
	$ 956,358	1,005,244
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Current Maturities of Long Term Debt	**$ 19,000**	19,000
Accounts Payable	**14,355**	17,646
Payable to Affiliates	**6,561**	4,467
Property Taxes	**8,262**	8,800
Other Non Income Taxes	**2,279**	2,963
Accrued Interest	**8,690**	8,998
Other	**140**	140
	59,287	62,014
Long Term Debt	**392,000**	411,000
Deferred Partnership Income Taxes	**3,337**	1,927
Other Liabilities	**436**	417
Partners' Capital	**501,298**	529,886
	$ 956,358	1,005,244

See accompanying notes to consolidated financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of Dollars)	2009	2008	2007
Cash Flow Increase (Decrease) from:			
Operating Activities			
Net Income	$ 127,412	123,436	128,301
Adjustments to Reconcile Net Income to Operating Cash Flows:			
Depreciation	58,503	58,522	58,046
Deferred Income Taxes	1,410	1,927	
Allowance for Funds Used During Construction	(129)	(310)	(438)
Changes in Current Assets and Liabilities:			
Accounts Receivable	3,958	2,291	(12,902)
Receivable from Affiliates	(183)	(1,132)	7,347
Accounts Payable	(3,291)	(8,822)	9,889
Payable to Affiliates	2,094	2,596	(491)
Property and Other Non Income Taxes	(1,222)	(1,182)	(8,787)
Other	1,702	(649)	(5,342)
	190,254	176,677	175,623
Investing Activities			
Investment in Utility Plant	(8,259)	(12,333)	(18,804)
Increase in Demand Loan Receivable from Affiliate	(8,507)	(25,467)	
	(16,766)	(37,800)	(18,804)
Financing Activities			
Repayment of Long Term Debt	(19,000)	(10,000)	(10,000)
Distribution to Partners	(156,000)	(159,200)	(193,500)
	(175,000)	(169,200)	(203,500)
Change in Cash and Cash Equivalents	(1,512)	(30,323)	(46,681)
Cash and Cash Equivalents:			
Beginning of Year	1,637	31,960	78,641
End of Year	$ 125	1,637	31,960
Supplemental Disclosure of Cash Flow Information:			
Cash Paid During the Year for:			
Interest (Net of Amounts Capitalized of $51, $115 and $184, Respectively)	$ 33,159	34,440	35,294
Partnership Income Taxes	$	2,574	

See accompanying notes to consolidated financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

Great Lakes Gas Transmission Limited Partnership (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 and eastern Canada. The partners, their parent companies, and partnership ownership percentages at December 31 are as follows:

Partner (Parent Company)	Ownership % 2009	Ownership % 2008
General Partners:		
TransCanada GL, Inc. (TransCanada PipeLines Limited)	**46.45**	46.45
TC GL Intermediate Limited Partnership (TC PipeLines, LP)	**46.45**	46.45
Limited Partner:		
Great Lakes Gas Transmission Company (TransCanada PipeLines Limited)	**7.10**	7.10

On February 22, 2007 (acquisition date), TC PipeLines, LP and TransCanada PipeLines Limited (TransCanada) acquired El Paso Corporation's (El Paso) 46.45% ownership interest in the Partnership and 50% interest in Great Lakes Gas Transmission Company (Company), respectively.

The day-to-day operation of the Partnership activities is the responsibility of the Company pursuant to the Partnership's Operating Agreement with the Company. The Partnership is charged for the salaries, benefits, and expenses of the Company and affiliates for services attributable to its operations.

TransCanada has announced a reorganization of its U.S. Operations, which will include the closing of certain offices, relocation of employees and equipment, and some severance costs. It is expected that the reorganization will be complete in 2010, with some activities completed in 2009. Costs borne by the Partnership in 2009 were approximately $1 million

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary until December 2009. GLGT Aviation Company owned a fractional interest in a transport aircraft used principally for pipeline operations. In October 2009, GLGT Aviation Company sold its interest in the aircraft. In December 2009, GLGT Aviation Company was liquidated. Intercompany amounts have been eliminated.

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.

Demand Loan Receivable

Effective August 1, 2008, the Partnership entered into a Cash Management Agreement with its affiliate, TransCanada PipeLine USA Ltd. Monies advanced under the agreement are considered to be a loan, accruing interest and repayable on demand.

Under the Partnership's cash management system, the bank notifies the Partnership daily of checks presented for payment against its disbursement account. The Partnership transfers funds from short-term investments or offsets its Demand Loan Receivable from Affiliates to cover the checks presented for payment. This system results in a book cash overdraft in the disbursement account as a result of checks outstanding. The book overdraft, which was reclassified to accounts payable, was $3.6 million and $1.6 million at December 31, 2009 and 2008, respectively. The book overdraft is classified as operating cash flows on the Consolidated Statement of Cash Flows.

Fair Value

The fair value of long term debt is discussed in footnote 4. All other financial instruments approximate fair value and are classified as Level I in the fair value hierarchy due to the short maturity of these instruments.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles (GAAP) 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 those estimates.

Regulation

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership's accounting policies conform to Financial Accounting Standards Board Codification (ASC) 980, *Regulated Operations*. Accordingly, certain asset or liabilities that result from 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 ASC 980, considering such factors as regulatory changes, the impact of competition, and the ability to recover regulatory assets. As of December 31, 2009 and 2008, there are no significant regulatory assets or liabilities reflected in these consolidated financial statements.

On November 19, 2009, the FERC instituted proceedings under Section 5 of the Natural Gas Act to review the tariff rates of the Partnership. As directed under the FERC order, the Partnership filed a cost and revenue study on February 4, 2010. The proceeding is set on a Track II schedule, which among other things, calls for the presiding Administrative Law Judge to issue an Initial Decision by mid-November 2010.

Revenue and Accounts Receivable

The Partnership generates transportation revenues based on transportation service contracts under a tariff regulated by the FERC. The tariff specifies maximum transportation rates and the contracts' general terms and conditions of service. The majority of the service contracts are for firm service in which the customers pay a reservation fee for capacity on the pipeline system regardless of whether they actually utilize their reserved capacity. The Partnership recognizes reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. In addition to the reservation fee, a utilization fee is charged and the related revenue is recognized based on the volume of natural gas transported.

Accounts receivable are reported at the invoiced amount. The Partnership establishes an allowance for losses on accounts receivable if it is determined that collection of all or a portion of the outstanding balance is not reasonably assured. The Partnership also considers historical industry data and customer credit trends. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received differs from the contractual amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from customers and interconnecting pipelines at an index price. Imbalances are made up in kind, in accordance with the terms of the tariff.

Imbalances due from others are reported on the consolidated balance sheet as either accounts receivable or receivable from affiliates. Imbalances owed to others are reported on the consolidated balance sheet as either accounts payable or payable to affiliates. Imbalances are expected to settle within a year.

Materials and Supplies

Materials and supplies are valued at the lower of cost or market value with cost determined using the average cost method. The Partnership has an allowance for inventory obsolescence based on the aging of the inventory and potential realizability.

Gas Utility Plant and Depreciation

Gas utility plant is stated at cost and includes certain administrative and general expenses, plus an allowance for funds used during construction. The Partnership capitalizes major units of property replacements or improvements and expenses minor items. Planned major maintenance is accrued when an obligating event occurs, and is recorded using the direct expensing method or the deferral method. The cost of plant retired is charged to accumulated depreciation net of salvage and cost of removal. Depreciation of gas utility plant is computed using the composite (group) method. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The Partnership's principal operating assets, which comprise approximately 98% of total property, plant and equipment, are depreciated at an annual rate of 2.75%. The remaining assets are depreciated at annual rates ranging from 4% to 20%.

The allowance for funds used during construction represents the debt and equity costs of capital funds applicable to utility plant under construction, calculated in accordance with a uniform formula prescribed by the FERC. The rates used were 10.36%, 10.49%, and 10.25% for years 2009, 2008, and 2007, respectively.

A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Asset Retirement Obligations

The fair value of a liability for an asset retirement obligation is recorded during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. The Partnership has determined that asset retirement obligations exist for certain of 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 establish a liability for the obligations.

Income Taxes

The Michigan Business Tax (MBT), effective January 1, 2008, is an income tax levied at the partnership level. Income taxes, other than the MBT, are the responsibility of our partners and are not reflected in these consolidated financial statements. The Partnership is required, for FERC regulatory purposes, to account for income taxes as if it were a corporation.

3. AFFILIATED COMPANY TRANSACTIONS

Affiliated company amounts included in the Partnership's consolidated financial statements, not otherwise disclosed, are as follows:

(In Thousands)	**2009**	**2008**	**2007**
Transportation Revenues:			
TransCanada and affiliates	**$142,364**	144,137	135,629
El Paso and affiliates			1,537
Interest Income	**449**	453	

Affiliated transportation revenues are primarily provided under fixed priced contracts with remaining terms ranging from 1 to 8 years.

The Partnership has 831 MDth/d of long haul capacity under contract expiring on October 31, 2010, with its largest shipper, TransCanada. On November 3, 2009, the Partnership and TransCanada renewed contracts for one year for 470 MDth/d of capacity, some at a slightly discounted rate, and agreed to provide other transportation services. The remaining 361 MDth/d of capacity will expire October 31, 2010.

The Partnership reimbursed the Company and affiliates for salaries, benefits, and other administrative and operating incurred expenses. Benefits include pension, defined contribution plans, and other post-retirement benefits. The Partnership is charged for benefit plan expenses and other benefits by a TransCanada affiliate through a benefit rate on labor costs. Operating expenses charged by the Company and affiliates in 2009, 2008, and 2007 were $33,765,000, $34,261,000, and $26,836,000, respectively.

4. DEBT

(In Thousands)	2009	2008
Senior Notes, unsecured, interest due semiannually, principal due as follows:		
8.74% series, due 2010 to 2011	$20,000	30,000
9.09% series, due 2012 to 2021	100,000	100,000
6.73% series, due 2010 to 2018	81,000	90,000
6.95% series, due 2019 to 2028	110,000	110,000
8.08% series, due 2021 to 2030	100,000	100,000
	411,000	430,000
Less current maturities	19,000	19,000
Total long term debt less current maturities	$392,000	411,000

The aggregate estimated fair value of long term debt was $491,692,000 and $413,148,000 for 2009 and 2008, respectively. The fair value is determined using discounted cash flows based on the Partnership's estimated current interest rates for similar debt which is classified as Level II in the fair value hierarchy where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices.

The aggregate annual required repayments of Senior Notes is $19,000,000 for each year 2010 through 2014.

Under the most restrictive covenants in the Senior Note Agreements, approximately $221,000,000 of partners' capital is restricted as to distributions as of December 31, 2009.

5. CASH DISTRIBUTION POLICY

The Partnership's Management Committee determines the amount and timing of the distributions to partners. The Partnership's cash distribution policy generally results in distribution equal to 100 percent of distributable cash flow based upon earnings before interest, taxes, and depreciation less debt repayments and capital expenditures. The resulting distributions are subject to Management Committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

6. MICHIGAN BUSINESS TAX

The Partnership files the MBT return on a unitary basis with certain TransCanada affiliates. A tax payment agreement between the Partnership and TransCanada affiliates provides that the Partnership's MBT liability is determined as if a separate return was filed. Under the agreement, the Partnership remits its current MBT liability to an affiliate, accordingly any liability is included in payable to affiliates.

MBT for the years ended December 31, 2009 and 2008 consists of:

(In Thousands)	2009	2008
Current	$4,007	3,576
Deferred	1,410	1,927
	$5,417	5,503

The deferred tax liabilities as of December 31, 2009 and 2008 are as follows:

(In Thousands)		2009	2008
Deferred tax liabilities	non-regulated utility plant	$(2,753)	(1,466)
Deferred tax liabilities	regulated utility plant	(527)	(411)
Deferred tax liabilities	other	(57)	(50)
Net deferred tax liability		$(3,337)	(1,927)

As of December 31, 2009 and 2008, no valuation allowance is required.

7. ENVIRONMENTAL

By letter dated December 28, 2009, the Environmental Protection Agency (EPA) required the Partnership 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 the Partnership's compliance with the Clean Air Act. The Partnership is in the process of preparing its response and providing the information which is due by May 29, 2010. The results of this information request are not determinable at this time.

8. ACCOUNTING PRONOUNCEMENTS

The Partnership adopted the provisions of ASC 855 *Subsequent Events* in the third quarter of 2009. ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The adoption of this standard has not had a material impact on the Partnership's disclosures.

The Partnership adopted the provisions of ASC 105 *Generally Accepted Accounting Principles* during 2009. ASC 105 has become the source of authoritative GAAP recognized by the Financial Accounting Standards Board to be applied by nongovernmental entities. The adoption of this standard has had no impact on disclosures or amounts recorded in the Partnership's financial statements.

9. SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through February 11, 2010, 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.

NORTHERN BORDER PIPELINE COMPANY
INDEPENDENT AUDITORS' REPORT

Management Committee
Northern Border Pipeline Company:

We have audited the accompanying balance sheets of Northern Border Pipeline Company (the Company) as of December 31, 2009 and 2008, and the related statements of income, comprehensive income, cash flows, and changes in partners' equity for each of the years in the three-year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our 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, 2009 and 2008, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 16, 2010

NORTHERN BORDER PIPELINE COMPANY

BALANCE SHEETS

December 31, (In thousands)	2009	2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16,864	$ 21,655
Accounts receivable	23,843	32,781
Related party receivables	391	386
Materials and supplies, at cost	4,471	4,562
Prepaid expenses and other	1,508	1,421
Total current assets	47,077	60,805
Property, plant and equipment:		
In service natural gas transmission plant	2,513,825	2,491,977
Construction work in progress	813	12,366
Total property, plant and equipment	2,514,638	2,504,343
Less: Accumulated provision for depreciation and amortization	1,171,544	1,113,582
Property, plant and equipment, net	1,343,094	1,390,761
Other assets:		
Regulatory assets (Note 2)	20,091	21,678
Unamortized debt expense	2,791	2,311
Other	1,339	484
Total other assets	24,221	24,473
Total assets	$1,414,392	$1,476,039
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt (Note 5)	$	$200,000
Accounts payable	3,409	6,096
Related party payables	3,390	3,852
Accrued taxes other than income	22,713	26,280
Accrued interest	7,058	11,060
Other	1,389	1,455
Total current liabilities	37,959	248,743
Long-term debt, net of current maturities (Note 5)	564,549	430,435
Deferred credits and other liabilities		
Related party payables	753	1,507
Regulatory liabilities (Note 2)	7,189	4,741
Derivative financial instruments (Note 6)		3,633
Other	396	1,312
Total deferred credits and other liabilities	8,338	11,193

Commitments and contingencies (Note 8)

December 31, (In thousands)	**2009**	**2008**
Partners' equity:		
Partners' capital	**806,600**	791,376
Accumulated other comprehensive loss	**(3,054)**	(5,708)
Total partners' equity	**803,546**	785,668
Total liabilities and partners' equity	**$1,414,392**	$1,476,039

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

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF INCOME

Years Ended December 31, (In thousands)	2009	2008	2007
Operating revenue	$249,217	$293,105	$309,376
Operating expenses			
Operations and maintenance	48,695	51,260	54,057
Depreciation and amortization	61,870	61,081	60,733
Taxes other than income	22,103	26,765	29,379
Operating expenses	132,668	139,106	144,169
Operating income	116,549	153,999	165,207
Interest expense			
Interest expense	36,750	40,974	43,082
Interest expense capitalized	(137)	(182)	(11)
Interest expense, net	36,613	40,792	43,071
Other income (expense)			
Allowance for equity funds used during construction	235	323	30
Gain on sale of assets (Note 10)		16,166	
Other income	2,309	2,932	2,427
Other expense	(348)	(426)	(488)
Other income, net	2,196	18,995	1,969
Net income to partners	$ 82,132	$132,202	$124,105

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (In thousands)	2009	2008	2007
Net income to partners	$82,132	$132,202	$124,105
Other comprehensive income:			
Changes associated with hedging transactions	2,654	(3,267)	(3,419)
Total comprehensive income	$84,786	$128,935	$120,686

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)	2009	2008	2007
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	$ 82,132	$ 132,202	$ 124,105
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	62,218	61,464	61,115
Allowance for equity funds used during construction	(235)	(323)	(30)
Changes in components of working capital	(1,847)	(4,062)	1,457
Gain on sale of assets		(16,166)	
Other	(2,262)	(3,705)	(2,146)
Total adjustments	57,874	37,208	60,396
Net cash provided by operating activities	140,006	169,410	184,501
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	(11,090)	(20,538)	(10,636)
Investments in other assets		(3,834)	
Proceeds from sale of assets		20,000	
Net cash used in investing activities	(11,090)	(4,372)	(10,636)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	84,550		15,000
Distributions to partners	(151,458)	(181,320)	(172,668)
Issuance of debt	214,000	145,000	269,000
Retirement of debt	(280,000)	(130,000)	(273,000)
Debt financing costs	(799)		(257)
Net cash used in financing activities	(133,707)	(166,320)	(161,925)
Net change in cash and cash equivalents	(4,791)	(1,282)	11,940
Cash and cash equivalents at beginning of year	21,655	22,937	10,997
Cash and cash equivalents at end of year	$ 16,864	$ 21,655	$ 22,937
Supplemental disclosures for cash flow information:			
Cash paid for interest, net of amount capitalized	$ 40,987	$ 41,868	$ 44,481
Changes in components of working capital:			
Accounts receivable	$ 8,938	$ (1,474)	$ (1,234)
Related party receivables	(5)	2,368	(2,399)
Materials and supplies	91	(357)	(235)
Prepaid expenses and other	(87)	85	(388)
Accounts payable	(2,687)	(1,084)	2,602
Related party payables	(462)	(2,000)	3,313
Accrued taxes other than income	(3,567)	(1,345)	54
Accrued interest	(4,002)	(223)	(232)
Other current liabilities	(66)	(32)	(24)
Total	$ (1,847)	$ (4,062)	$ 1,457

Years Ended December 31, (In thousands)	2009	2008	2007

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, 2006	$437,029	$437,028	$ 978	$ 875,035
Net income to partners	62,052	62,053		124,105
Changes associated with hedging transactions			(3,419)	(3,419)
Equity contributions received	7,500	7,500		15,000
Distributions paid	(86,334)	(86,334)		(172,668)
Partners' equity at December 31, 2007	420,247	420,247	(2,441)	838,053
Net income to partners	66,101	66,101		132,202
Changes associated with hedging transactions			(3,267)	(3,267)
Distributions paid	(90,660)	(90,660)		(181,320)
Partners' equity at December 31, 2008	395,688	395,688	(5,708)	785,668
Net income to partners	41,066	41,066		82,132
Changes associated with hedging transactions			2,654	2,654
Equity contributions received	42,275	42,275		84,550
Distributions paid	(75,729)	(75,729)		(151,458)
Partners' equity at December 31, 2009	**$403,300**	**$403,300**	**$(3,054)**	**$ 803,546**

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 1,249-mile natural gas transmission pipeline 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, 2009 and 2008 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. The Management Committee designates the members of the Audit Committee, which consists of three members. One member is selected by the members of the Management Committee designated by the partner whose affiliate is the operator and two members are selected by the members of the Management Committee designated by the other partner.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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.

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, 2009 and 2008.

	December 31,		Remaining recovery/ settlement
	2009	2008	period
	(In thousands)		*(Years)*
Fort Peck lease option	$ 13,273	$ 12,052	41
Pipeline extension project	5,536	5,998	12
Unamortized loss on reacquired debt	44	176	Less than 1
Deferred rate case expenditures	1,174	1,566	3
Compressor usage surcharge tracker	64	1,886	1 to 2
Total regulatory assets	$ 20,091	$ 21,678	

At December 31, 2009 and 2008, respectively, we have reflected a regulatory liability of $7.2 million and $4.7 million on the balance sheets, related to negative salvage accrued for estimated net costs of removal of transmission plant. 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, a write-off of related regulatory assets and liabilities could be required.

Revenue Recognition

We transport gas for shippers under a tariff regulated by the FERC. The tariff specifies the maximum rates we may charge shippers and the general terms and conditions of transportation service on our pipeline system. We recognize revenue according to each transportation contract for transportation service that is provided to our customers. Customers with firm service transportation agreements pay a reservation fee for capacity on the pipeline system known as a reservation charge regardless of whether they actually utilize their reserved capacity. Firm service transportation customers also pay a fee known as a commodity charge that is based on the mileage and the volume of natural gas they transport. Under the capacity release provisions of our FERC tariff, shippers under firm contracts are allowed to release all or part of their capacity either permanently for the full term of the contract or temporarily. A temporary capacity release does not relieve the original contract shipper from its payment obligations if the replacement shipper fails to pay for the capacity temporarily released to it. Customers with interruptible service transportation agreements may utilize available capacity on our pipeline after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges based on mileage and the volume of natural gas they transport. An allowance for doubtful accounts is recorded in situations where collectibility is not reasonably assured. At December 31, 2008, we have reflected an allowance for doubtful accounts of approximately $0.6 million on the balance sheets. We do not own the gas that we transport, and therefore we do not assume the related natural gas commodity price risk.

Income Taxes

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

Cash and Cash Equivalents

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

Materials and Supplies

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

Property, Plant and Equipment and Related Depreciation and Amortization

Property, plant and equipment is stated at original cost. During periods of construction, we are permitted to capitalize an allowance for funds used during construction, which represents the estimated costs of funds used for construction purposes. The original cost of property retired is charged to accumulated depreciation and amortization. No retirement gain or loss is included in income except in the case of retirements or sales of entire regulated operating units or systems.

Maintenance and repairs are charged to operations in the period incurred. The provision for depreciation and amortization of the transmission line is an integral part of our FERC tariff. As a result of the settlement of our 2005 rate case, the effective depreciation rate applied to our transmission plant in 2009, 2008 and 2007 is 2.40 percent. The transmission plant depreciation rate of 2.40 percent is comprised of two components: one based on economic service life or capital recovery and one based on cost of removal, net of salvage value received, or negative salvage. We accrue the estimated net costs of removal of transmission plant as a regulatory liability, which does not represent an existing legal obligation. The net cost of removal incurred on retirements of transmission plant is recorded as a reduction to the regulatory liability. Composite rates are applied to all other functional groups of property having similar economic characteristics.

Asset Retirement 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.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received by a pipeline system or storage facility differs from the contractual amount of natural gas scheduled to be delivered or received. We value these imbalances due to or from shippers and interconnecting parties at an appropriate index price. 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. All imbalances are classified as current.

Risk Management

We utilize financial instruments to reduce our market risk exposure to interest rate fluctuations and achieve a more predictable cash flow. We follow established policies and procedures to assess risk and approve, monitor and report our financial instrument activities. We do not use these instruments for trading purposes. All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded on the balance sheets as either an asset or liability measured at their fair value (see Note 7). We record changes in the derivative's fair value currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting (see Note 6).

Unamortized Debt Premium, Discount and Expense

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

Operating Leases

We have non-cancelable operating leases for office space and rights-of-way. We record rent expense over the lease term as it becomes payable.

Impairment of Long-Lived Assets

We assess our long-lived assets for impairment whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. In step one of the impairment test, an impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets. An impairment loss would be recorded equal to the difference between the carrying value and the fair value of the long-lived asset. This type of analysis requires us to make assumptions and estimates regarding industry economic factors and the profitability of future business strategies. We determined that there were no asset impairments in 2009 or 2008.

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.

Recent Accounting Pronouncements

We adopted the provision of ASC 820-10-65, *Fair Value Measurements and Disclosures* for all non-financial assets and liabilities measured on a non-recurring basis subsequent to initial recognition, effective January 1, 2009. The adoption of ASC 820-10-65 had no material impact on our results of operations or financial position.

ASC 105, *Generally Accepted Accounting Principles* ("GAAP") has become the source of authoritative GAAP recognized by the Financial Accounting Standards Board to be applied by nongovernmental entities. This standard is effective for our interim reporting period ending after September 15, 2009. The adoption of this standard has had no impact on disclosures or amounts recorded in our financial statements.

ASC 855, *Subsequent Events* establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This standard has been effective for our interim reporting since June 30, 2009 and has not had a material impact on disclosures or amounts recorded in our financial statements.

3. RATES AND REGULATORY ISSUES

The FERC regulates the rates and charges for transportation of natural gas in interstate commerce. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's actual prudent historical cost investment. The rates and terms and conditions for service are found in each pipeline's FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

Effective January 1, 2007, we implemented new rates as a result of the settlement of our 2005 rate case. For the full transportation route from Port of Morgan, Montana to the Chicago area, our transportation rate is approximately $0.44 per Dekatherm (Dth), which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The settlement also provided for seasonal rates for short-term transportation services. Seasonal maximum rates vary on a monthly basis from approximately $0.54 per Dth to approximately $0.29 per Dth for the full transportation route from Port of Morgan, Montana to the Chicago area. The settlement included a three-year moratorium on filing rate cases and participants challenging these rates, and requires that we file a rate case within six years from the date the new rates went into effect.

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 a regulatory liability or a regulatory asset, respectively, on the balance sheets. The compressor usage surcharge rate is adjusted annually. The regulatory liability or regulatory asset will reflect the net over or under recovery of actual compressor usage related costs at the date of the balance sheets. As of December 31, 2009 and 2008, we had recorded $0.1 million and $1.9 million, respectively, as a regulatory asset on the accompanying balance sheets for the net under recovery of compressor usage related costs.

In February 2008, we filed an application for the Des Plaines Project with the FERC to construct own and operate interconnect facilities including a 1,600 horsepower compressor facility near Joliet, Illinois. The Des Plaines Project cost approximately $17 million and was financed with a combination of debt and equity. A certificate order issued by the FERC authorizing the construction of the Des Plaines Project was received in July 2008 and construction commenced in September. The facilities were placed in service in March 2009.

4. MAJOR CUSTOMERS

For the year ended December 31, 2009, shippers providing significant operating revenues were BP Canada Energy Marketing Corp. (BP Canada) and Tenaska Marketing Ventures with revenues of $41.9 million and $26.7 million, respectively. For the year ended December 31, 2008, shippers providing significant operating revenues were BP Canada and Cargill Inc. (Cargill) with revenues of $38.8 million and $32.4 million, respectively. For the year ended December 31, 2007, shippers providing significant operating revenues were BP Canada, Nexen Marketing U.S.A. Inc. and Cargill with revenues of $49.7 million, $44.1 million, and $42.0 million, respectively.

5. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

December 31, (In thousands)	**2009**	**2008**
2007 Credit Agreement average interest rate of 0.52% and 3.36% at December 31, 2009 and 2008, respectively, due 2012	**$215,000**	$181,000
1999 Senior Notes 7.75%, due 2009		200,000
2001 Senior Notes 7.50%, due 2021	**250,000**	250,000
2009 Senior Notes 6.24%, due 2016	**100,000**	
Unamortized debt discount	**(451)**	(565)
Subtotal	**564,549**	630,435
Current maturities		(200,000)
Long-term debt	**$564,549**	$430,435

On August 26, 2009, we issued $100 million of 6.24 percent Senior Notes due August 26, 2016. The proceeds of the 6.24 percent Senior Notes along with equity contributions, borrowings under the revolving credit agreement and cash generated by operating activity was used to repay $200 million of 7.75 percent Senior Notes due September 1, 2009.

On April 27, 2007, we entered into a $250 million amended and restated revolving credit agreement (2007 Credit Agreement) with certain financial institutions. The 2007 Credit Agreement was used to refinance the outstanding indebtedness under our $175 million revolving credit agreement dated as of May 16, 2005 and was used to repay all of the $150 million of our 6.25 percent Senior Notes due May 1, 2007. The 2007 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, 2009, based on the principal commitment amount of $250 million, available capacity under the 2007 Credit Agreement was $35 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 2007 Credit Agreement by an aggregate amount not to exceed $100 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 2007 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 facility fee of 0.05 percent based on the principal amount of the commitment of $250 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 2007 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 debt to EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges)) of no more than 4.75 to 1. Pursuant to the 2007 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 three full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2007 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, 2009, we were in compliance with all of our financial covenants.

Aggregate required repayments of long-term debt for the next five years is $215 million in 2012. Aggregate required repayments of long-term debt thereafter total $350 million. There are no required repayment obligations for 2010, 2011, 2013 or 2014.

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. During the year ended December 31, 2007, we amortized approximately $0.7 million as a reduction to interest expense. Amounts received or paid related to terminated interest rate swap agreements for fair value hedges were fully amortized at June 30, 2007.

In August 2007, we entered into a zero cost interest rate collar agreement (the "Collar Agreement") to limit the variability of the interest rate on $140 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 percent and a cap of 5.36 percent. We have designated the Collar Agreement as a cash flow hedge. No amounts were recognized in income due to hedge ineffectiveness of the Collar Agreement.

The following table represents the unrealized (gains) losses recorded in accumulated other comprehensive income (loss) on the statements of changes in partners' equity.

	Years Ended December 31,		
Derivatives under Cash Flow Hedging Relationships	**2009**	**2008**	**2007**
		(In thousands)	
Cash flow hedges	**$ (3,633)**	**$ 1,781**	**$ 1,852**

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 tables 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 to interest expense on the statements of income.

Net Gain Reclassified from AOCI into Income (Effective Portion)	Statements of Income Caption	Years Ended December 31, 2009	2008	2007
		(In thousands)		
Cash flow hedges	Interest expense	**$ 979**	**$ 1,486**	**1,567**

At December 31, 2009, we have realized losses recorded in accumulated other comprehensive loss of approximately $3.1 million. We expect to reclassify approximately $0.2 million from accumulated other comprehensive loss as an increase to interest expense in 2010.

The following table represents the location and fair value of our derivative instruments in the balance sheets.

Derivatives Designated as Hedging Instruments	Balance Sheets Caption	December 31, 2009	2008
		(In thousands)	
Cash flow hedges	Derivative financial instruments	**$**	**$ 3,633**

7. FAIR VALUE MEASUREMENTS

Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2009 and 2008. 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.

	2009		2008	
(In thousands)	Carrying amount	Fair Value	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	**$16,864**	**$16,864**	$21,655	$21,655
Financial liabilities:				
Long-term debt	**$564,549**	**$612,009**	$630,435	$627,855
Derivative financial instruments	**$**	**$**	$3,633	$3,633

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

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 is determined using level 2 inputs as discussed in "Fair Value Hierarchy." 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 2007 Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

Derivative financial instruments The fair value of derivative financial instruments is determined using level 2 inputs as discussed in "Fair Value Hierarchy."

Fair Value Hierarchy

We adopted the provision ASC 820, Fair Value Measurements and Disclosures (ASC 820) on January 1, 2008. Under ASC 820, 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 Company 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.

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, 2009, 2008 and 2007 were $1.4 million, $2.5 million, and $1.5 million, respectively. Our future minimum lease payments, which assume we exercise the option to renew a pipeline right-of-way lease in April 2011 for a term of 25 years (discussed below), are as follows:

Year ending December 31, (In thousands)

2010	$2,214
2011	1,917
2012	1,918
2013	1,896
2014	1,889
Thereafter	57,295
	$67,129

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 grants 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 will make additional annual option payments of approximately $1.5 million through March 31, 2011.

Transition Related Costs

We are required to pay $3.6 million over a five year period under a transition services agreement between ONEOK Partners GP and TransCanada Northern Border, related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used or currently in use for our operations. During 2007, a charge of $2.3 million was recorded in operations and maintenance expense and $1.3 million was recorded as natural gas transmission plant for the shared equipment and furnishings previously used or currently in use by us, respectively. Amounts related to this obligation are included in related party payables on the balance sheets. Future remaining payments for this obligation are as follows:

Year ending December 31, (In thousands)

2010	$753
2011	753
	$1,506

Environmental Matters

We received a Notice of Violation (NOV) from the United States Environmental Protection Agency (EPA) dated February 2, 2009 alleging that we were in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on our system. We dispute the NOV. At this time, we are unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty, but do not expect such amounts to be material to our financial condition.

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 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, 2009, 2008 and 2007, we paid distributions to our general partners of $151.5 million, $181.3 million and $172.7 million, respectively. In 2009, we received contributions from our general partners in the amount of $84.6 million. During the first quarter of 2009, we received $8.6 million, which was used to fund 50 percent of the costs of construction of the Des Plaines Project. During the third quarter of 2009, we received $76 million, which was used for the retirement of the 7.75 percent Senior Notes due September 1, 2009. In 2007, we issued an equity cash call to our general partners in the amount of $15.0 million for the previously approved 2007 equity cash call. The proceeds were used to repay indebtedness.

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, 2009, 2008 and 2007, our charges from TransCanada and its affiliates totaled approximately $25.5 million, $28.6 million and $22.5 million, respectively.

Prior to April 1, 2007, the day-to-day management of our affairs was the responsibility of ONEOK Partners GP, L.L.C. (ONEOK Partner GP) pursuant to an operating agreement between ONEOK Partners GP and us. ONEOK Partners GP also utilized ONEOK Inc. (ONEOK) and its affiliates for management services related to us. We were charged for the salaries, benefits and expenses of ONEOK Partners GP, ONEOK and its affiliates attributable to our operations. For the year ended December 31, 2007, our charges from ONEOK Partners GP and its current and former affiliates totaled approximately $9.3 million. Our 2007 charges include $3.6 million for transition related costs. See Note 8 for discussion of transition related costs.

For the years ended December 31, 2009, 2008 and 2007, 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), a subsidiary of ONEOK, for 2009, 2008 and 2007 was $4.2 million, $5.0 million and $5.1 million, respectively. At December 31, 2009 and 2008, we had outstanding receivables from ONEOK Energy of $0.4 million and $0.4 million, respectively.

In March 2008, we formed a wholly-owned subsidiary, Bison Pipeline LLC (Bison) to develop the Bison Project. The Bison Project is a proposed pipeline system that would extend from natural gas gathering facilities located in the Powder River Basin in Wyoming to a point of interconnection with our pipeline system in Morton County, North Dakota.

In August 2008, we sold Bison to TransCanada Pipeline USA Ltd., a wholly-owned subsidiary of TransCanada, for $20.0 million. In connection with this transaction, we recorded a gain on sale of $16.2 million. Through the effective date of the sale, Bison received services from TransCanada and its affiliates totaling approximately $2.0 million in 2008.

In June 2008, in connection with the Des Plaines Project, we entered into an interconnect agreement with ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada. The interconnect agreement provides that we will reimburse ANR for the cost of certain of the interconnect facilities to be owned by ANR. In 2008, we paid ANR $0.5 million.

11. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $32.8 million was declared and paid on February 1, 2010 for the fourth quarter of 2009.

We have evaluated subsequent events through February 16, 2010, 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.

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