TC PIPELINES LP
Form 10-K
March 02, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2006

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 Number)
110 Turnpike Road, Suite 203 **Westborough, Massachusetts** (Address of principal executive offices)	**01581** (Zip code)

508-871-7046

(Registrant s telephone number, including area code)

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

None

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

Common units representing limited partner interests

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes o No x

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 x

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

Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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.

x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerate filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer x Non-accelerated filer o

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

Yes o No x

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as at June 30, 2006 was approximately $510.2 million.

As of March 2, 2007, there were 34,856,086 of the registrant s common units outstanding.

TC PIPELINES, LP

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

PART I

Item 1. Business

BUSINESS OF TC PIPELINES, LP

TC PipeLines, LP is a Delaware limited partnership formed in 1998. TC PipeLines, LP and its subsidiary limited partnerships, TC PipeLines Intermediate Limited Partnership (TC PipeLines ILP), TC Tuscarora Intermediate Limited Partnership (TC Tuscarora ILP) and TC GL Intermediate Limited Partnership (TC GL ILP) are collectively referred to herein as TC PipeLines or the Partnership. In this report, references to we , us or our collectively refer to TC PipeLines or the Partnership. The general partner of the Partnership is TC PipeLines GP, Inc. (TC PipeLines GP), an indirect wholly-owned subsidiary of TransCanada Corporation (TransCanada).

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

We own a 46.45 per cent interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes), which we acquired on February 22, 2007 from El Paso Corporation. The remaining 53.55 interest in Great Lakes is held by TransCanada.

We own a 50 per cent interest in Northern Border Pipeline Company (Northern Border Pipeline) including 20 per cent acquired on April 6, 2006. The remaining 50 per cent interest in Northern Border Pipeline is held by ONEOK Partners, L.P. (ONEOK Partners), formerly known as Northern Border Partners, LP, a publicly traded limited partnership that is controlled by ONEOK, Inc. At December 31, 2006, each partner held a 50 percent voting interest on the Management Committee of Northern Border Pipeline.

We also own or control a 99 per cent interest in Tuscarora Gas Transmission Company (Tuscarora). We originally acquired a 49 per cent interest from TCPL Tuscarora Ltd., an indirect wholly-owned subsidiary of TransCanada, in September 2000, which continues to hold a one per cent general partner interest in Tuscarora. The Partnership purchased its remaining interest in Tuscarora from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, on December 19, 2006.

At March 2, 2007, we had 34,856,086 common units outstanding, of which 24,142,935 were held by the public, 8,678,045 were held by TransCan Northern Ltd. and 2,035,106 were held by the general partner, both wholly-owned subsidiaries of TransCanada. TransCanada, through its ownership of the Partnership s general partner, holds a two per cent general partner interest in the Partnership. In addition to the distributions received as a common unitholder, the general partner also receives incentive distributions if quarterly cash distributions on the common units exceed levels specified in the partnership agreement (see Item 5. Market for Registrant s Common Units, Related Security Holder Matters and Issuer Purchases of Equity Securities.)

Recent Developments

On February 22, 2007, the Partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation. The total purchase price was $962 million, subject to certain closing adjustments, and included the indirect assumption of approximately $212 million of debt. The acquisition was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600 million which closed concurrently with the acquisition. TransCan Northern Ltd. purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300 million. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with this transaction. The amount available under the senior credit facility increased from $410 million to $950 million, consisting of a $700 million senior term loan and a $250 million senior revolving credit facility, with $194 million of the senior term loan available being terminated upon closing of the acquisition. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private equity placement.

TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the remaining 3.55 per cent interest simultaneously with the Partnership s acquisition of its interest. A wholly-owned subsidiary of TransCanada also became the operator of Great Lakes.

On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. Upon the acquisition, TC PipeLines began to consolidate its interest in Tuscarora, as the Partnership owns or controls 99 per cent. In connection with this transaction, TransCan Northwest Border Ltd. (TransCan), an affiliate of TransCanada, became the operator of Tuscarora, which was previously operated by an affiliate of Sierra Pacific Resources.

BUSINESS OF GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Great Lakes Transmission Company (Company) was formed by TransCanada and American Natural Resources Company (ANRC). The Federal Energy Regulatory Commission (FERC) certificated the Company to construct its initial facilities in 1967. In 1990, the Company transferred its pipeline assets to Great Lakes Gas Transmission, L.P. (Great Lakes), which is a Delaware limited partnership. Great Lakes is owned 46.45 per cent by TC GL ILP, with the remainder owned by TransCanada.

The major policies of Great Lakes are established by the Management Committee, which consists of six members, three of whom are designated by us and three of whom are designated by TransCanada. All decisions by the Management Committee require unanimous consent. An Executive Committee which consists of three members: one Partnership Committee Member, one TransCanada Committee Member and the Great Lakes President, a non-voting member. The Executive Committee has all of the powers of the Management Committee in the management of Great Lakes business.

Great Lakes Pipeline System

Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba and extends across Minnesota, northern Wisconsin and Michigan, and redelivers gas to TransCanada at the international border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

Operating revenue is derived from the transportation of natural gas. The maximum transportation rates that Great Lakes may charge are 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 that include the recovery of Great Lakes cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set in a rate case, Great Lakes is not permitted to adjust its rates to reflect changes in costs or contract demand until a new rate case is filed and approved by the FERC. As a result, Great Lakes earnings and cash flow depend on costs incurred, contracted capacity and transportation path, the volume of gas transported and its ability to sell capacity at acceptable rates.

Great Lakes tariff is approved by the FERC and specifies the maximum rates, as well as, the general terms and conditions for natural gas transportation service on its pipeline. The tariff also allows for services to be provided under negotiated and discounted rates.

The Great Lakes mainline transmission pipes have diameters ranging from 10 inches to 36 inches. The Great Lakes system consists of approximately 2,115 miles of pipeline with a design capacity of 2,600 MMcf/d. Average throughput was 2,244 MDth/d in 2006, 2,376 MDth/d in 2005 and 2,200 MDth/d in 2004. Great Lakes has 14 compressor stations with a total of 438,000 horsepower and measurement facilities to support the 13 receipt points and 51 delivery points for gas.

Title to Properties

Great Lakes holds all rights, titles and interests in its pipeline system. With respect to real property, Great Lakes owns sites for compressor stations, meter stations, a corporate office and derives interest from leases, easements, rights-of-way, permits and licenses from landowners or governmental authorities permitting land use for construction and operation of its pipeline.

Supply

Great Lakes customers primary source of natural gas is the Western Canada Sedimentary Basin. In 2006, approximately 90 per cent of the natural gas Great Lakes transported was produced in Canada. For this reason, the continuous supply of Canadian natural gas is crucial to Great Lakes long-term financial condition.

The amount of Canadian natural gas available for export is the most significant factor affecting the volume of Canadian natural gas transported by Great Lakes system. The amount of Canadian natural gas available for export is determined by:

- Canadian natural gas production levels;
- demand for Canadian natural gas in Canada; and
- storage capacity for Canadian natural gas and demand for storage injection.

The extent to which Canadian natural gas available for export will be transported on Great Lakes system is affected by:

- demand for Canadian natural gas in other U.S. consumer markets;
- available transportation capacity and related market pricing options on other pipelines;
- natural gas from other supply sources that can be transported to the Midwestern U.S.;
- the natural gas market price spread between Alberta, Canada and the Midwestern U.S., which reflects the relative supply and demand for Canadian natural gas in Canada and in the U.S.; and
- storage capacity in the U.S. and Eastern Canada and the related demand for storage injection.

Demand

Demand for natural gas transportation service on Great Lakes system is directly related to demand for natural gas in the markets that its customers serve. Factors that may impact demand for natural gas include:

- weather conditions;
- economic conditions;
- government regulation;
- the availability and price of alternative energy sources;
- fuel conservation measures; and
- technological advances in fuel economy and energy generation devices.

Furthermore, factors that may impact demand for natural gas transportation service on Great Lakes system include:

- the ability and willingness of natural gas shippers to utilize Great Lakes system over alternative pipelines;
- transportation rates; and

- the volume of natural gas delivered to Midwestern U.S. and Eastern Canadian markets from other supply sources and storage facilities.

Great Lakes primary exposure to market risk occurs when existing transportation contracts expire and are subject to renegotiation. 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. In addition to general demand for natural gas, regional economic conditions, climate, trends in production, available pipeline capacity and natural gas storage inventories in each market area can also impact the basis differential and affect demand for transportation service on Great Lakes system.

Seasonality

As a turbine based system, Great Lakes design day capability at the Emerson inlet is approximately 2.45 Bcf/day during the winter and 2.3 Bcf/day during the summer. Though the winter flow capability is higher than the summer capability, the market demand for Great Lakes full-haul service can be just the opposite.

The demand for Great Lakes long haul service is at its highest during peak storage fill time periods. This is due to the approximate 880 Bcf of working gas storage located at the end of the Great Lakes system in Michigan and Ontario. The high demand usually begins in the spring and extends through most of the summer. The transportation value across the Great Lakes system is at its highest in conjunction with storage fill requirements.

The portion of Great Lakes capacity that is contracted under short-term (less than one year) transportation agreements is subject to seasonal variations. During the winter, there is also strong demand for Great Lakes services to meet the peak winter demand requirements of northern Minnesota, northern Wisconsin, and Michigan. These deliveries are predominantly met through Great Lakes transportation services other than long haul. For example, significant backhauls on Great Lakes from Michigan storage fields supply the Wisconsin market via ANRC. In fact, the aggregated peak day of all short haul and long haul flows occurs during the winter. Approximately six per cent of Great Lakes capacity was contracted on a short-term basis in 2006.

Finally, Great Lakes experiences significant winter volatility in the utilization of its long haul contracts due to downstream constraints on the Union Gas and TransCanada systems. As the demand for storage withdrawals from Dawn increase to serve points east, so does the level of downstream constraint which in turn strands Great Lakes long haul capacity.

Customers and Contracting

The majority of Great Lakes capacity has been contracted to TransCanada and is used by TransCanada customers to transport Western Canadian gas to Eastern Canadian and U.S. markets. ANR Pipeline, which is wholly-owned by TransCanada, also holds capacity on Great Lakes, to integrate its Michigan storage complex with its Wisconsin pipeline system. Various local distribution companies in Minnesota, Wisconsin and Michigan contract for transportation on Great Lakes to add Canadian gas to their supply mix. In addition, marketers and producers hold transportation capacity on Great Lakes, either directly or through the capacity release program, and use Great Lakes flexibility to deliver gas to markets, interconnecting pipelines and storage facilities along its system to maximize their optionality value of their transportation contracts.

Although Great Lakes has traditionally operated under long-term contracts, in response to changing market conditions, it has begun to market its capacity to a wide variety of producers, marketers and local distribution companies in the U.S. and Canada. Existing transportation contracts mature at varying times and in varying amounts of throughput capacity. Approximately 16 per cent of Great Lakes contracted capacity expired in 2006 and 44 per cent will expire by December 31, 2008. Great Lakes ability to extend and/or renew expiring contracts will depend on competitive alternatives, the regulatory environment, and market and supply factors at the relevant dates these contracts are extended or expire. ANR Pipeline holds over 1,100 Mdth/d of the 2006 expiring contracts on Great Lakes, and expects to roll over its contracts. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions, and judgments concerning future market trends and volatility. Subject to regulatory requirements, Great Lakes attempts to re-contract or remarket its capacity at the maximum rates allowed under its tariffs. Currently Great Lakes has discounted a portion of its capacity.

In 2006, TransCanada and ANR Pipeline contracts represented approximately 55 per cent and three per cent, respectively, of Great Lakes revenue.

Competition

Great Lakes principal business comes from its position as a link in the chain of transportation to move natural gas from Western Canada to Eastern Canadian markets. Natural gas is transported by TransCanada from Western Canada to Emerson, from Emerson to St. Clair by Great Lakes, and from St. Clair to Dawn and points further east by TransCanada. The primary competition for Great Lakes is from Western Canada to Dawn on TransCanada. Alternative routes from Western Canada to Ontario are the Foothills PipeLine - Northern Border Pipeline Company - Vector Pipeline route and the Alliance Pipeline - Vector route. In addition, gas sourced from the Rockies, Mid-continent and Gulf Coast can be delivered to Chicago and re-delivered to Ontario via Vector Pipeline.

Environmental and Safety Matters

Great Lakes operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment. Failure to comply with these laws and regulations can result in substantial penalties, enforcement actions and remedial liabilities. Although Great Lakes believes its operations and facilities are in compliance in all material respects with applicable environmental laws and safety regulations, it cannot provide any assurances that compliance with current and future laws and regulations will not have a material adverse effect on its financial position or results of operations.

Pipeline Safety Great Lakes is subject to U.S. Department of Transportation pipeline integrity management regulations. The Pipeline Safety Improvement Act 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. Great Lakes is on schedule to meet the required assessment of 50 per cent of the highest priority high consequence areas by the end of 2007.

Air and Water Emissions The Clean Air Act, the Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the U.S. Under the Clean Air Act, a federal operating permit is required for sources of significant air emissions. Great Lakes may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants discharged in U.S. water. Although Great Lakes cannot provide any assurances, it believes that it is in compliance with state and federal requirements related to these regulations.

Employees

As of March 2, 2007, Great Lakes had approximately 170 employees, none of whom are subject to a collective bargaining agreement.

BUSINESS OF NORTHERN BORDER PIPELINE COMPANY

Northern Border Pipeline is a Texas general partnership that was formed in 1978. Northern Border Pipeline provides natural gas transportation services and is a leading transporter of natural gas imported from Canada into the U.S. ONEOK Partners, through its subsidiary ONEOK Partners Intermediate Limited Partnership, and TC PipeLines, through its subsidiary TC PipeLines ILP, each own a 50 percent interest in Northern Border Pipeline. ONEOK Partners and TC PipeLines are publicly-traded master limited partnerships. The general partner of ONEOK Partners is ONEOK Partners GP, LLC (ONEOK Partners GP), a subsidiary of ONEOK Inc. TC PipeLines GP, a subsidiary of TransCanada, is the general partner of TC PipeLines.

Northern Border Pipeline is 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. At December 31, 2006, each partner held a 50 percent voting interest on the Management Committee.

The day-to-day management of Northern Border Pipeline s affairs is currently the responsibility of ONEOK Partners GP until March 31, 2007, pursuant to an operating agreement between Northern Border Pipeline and ONEOK Partners GP. Northern Border Pipeline is charged by ONEOK Partners GP for the salaries, benefits and expenses of ONEOK Partners GP attributable to Northern Border Pipeline s operations. ONEOK Partners also utilizes ONEOK and its affiliates for management services related to Northern Border Pipeline. Effective April 1, 2007, TransCan will become Northern Border Pipeline s operator.

Recent Developments

The following is a summary of Northern Border Pipeline s significant developments during 2006. Additional information regarding most of these items may be found elsewhere in this annual report or in previous reports filed with the U.S. Securities and Exchange Commission (SEC).

Purchase and Sale of Partnership Interest In April 2006, ONEOK Partners sold a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines. ONEOK Partners and TC PipeLines each own a 50 percent interest in Northern Border Pipeline.

Amended and Restated Partnership Agreement In April 2006, Northern Border Pipeline s General Partnership Agreement was amended and restated as a result of the ownership interest change. Under the First Amended and Restated General Partnership Agreement:

- The Management Committee 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.

- ONEOK Partners GP will be Northern Border Pipeline s operator until March 31, 2007. Effective April 1, 2007, TransCan will become Northern Border Pipeline s operator under a new operating agreement.

Operating Agreement In April 2006, Northern Border Pipeline entered into an operating agreement with TransCan. Under the new operating agreement, TransCan will become Northern Border Pipeline s operator effective April 1, 2007.

Chicago III Expansion Project In April 2006, the Chicago III Expansion Project was placed into service as planned, adding approximately 130 MMcf/d of transportation capacity on the eastern portion of Northern Border Pipeline s system into the Chicago market area.

Settlement of Rate Case In September 2006, Northern Border Pipeline filed a stipulation and agreement which documented the settlement of its rate case. The settlement was reached between Northern Border Pipeline and its participant customers and was supported by the FERC trial staff. In November 2006, the FERC approved the uncontested settlement of Northern Border Pipeline s rate case. Northern Border Pipeline refunded $10.8 million to its customers in the fourth quarter of 2006. Settlement rates were in effect January 1, 2007. Additional information about the regulatory proceedings is included in this section of this report under Business of Northern Border Pipeline Company Government Regulation.

Northern Border Pipeline s System

Northern Border Pipeline s transportation system provides pipeline access to the Midwestern U.S. from natural gas reserves in the Western Canada Sedimentary Basin, which is located in the Canadian provinces of Alberta, British Columbia and Saskatchewan. Additionally, Northern Border Pipeline transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana and synthetic gas produced at the Dakota Gasification plant in North Dakota. Northern Border Pipeline transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. The 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. Along the pipeline are 17 compressor stations with a total of 515,000 horsepower, measurement facilities to support the receipt and delivery of gas at ten receipt and 48 delivery points, four field offices and a microwave communication system with 50 tower sites.

Northern Border Pipeline s operating revenue is derived from the transportation of natural gas. The maximum transportation rates that Northern Border Pipeline may charge are established in a FERC proceeding known as a rate case. Northern Border Pipeline s tariff specifies the maximum rates and the general terms and conditions for natural gas transportation service on its pipeline. 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 that include the recovery of Northern Border Pipeline s cost-based investment, operating expenses and a reasonable return for its investors. The tariff also allows for services to be provided under negotiated and discounted rates. Once maximum rates are set in a rate case, Northern Border Pipeline is not permitted to adjust its rates to reflect changes in costs or contract demand until a new rate case is filed and approved by the FERC. As a result, Northern Border Pipeline s earnings and cash flow depend on costs incurred, contracted capacity and transportation path, the volume of gas transported and its ability to sell available capacity based on current market conditions.

Northern Border Pipeline s transportation contracts include specifications regarding the receipt and delivery of natural gas at points along the pipeline system. The type of transportation contract, either firm or interruptible service, determines the basis by 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. Firm service transportation customers also pay a fee known as a commodity charge that is based on mileage and the volume of natural gas they transport. Northern Border Pipeline s firm contracts have terms ranging from one day to nine years. Customers with interruptible service transportation agreements may utilize available capacity on Northern Border Pipeline s system 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. For the year ended December 31, 2006, approximately 96 per cent of Northern Border Pipeline s transportation revenue was derived from reservation charges and the remaining 4 per cent was attributable to commodity charges.

Construction of Northern Border Pipeline s system was initially completed in 1982, followed by expansions or extensions in 1991, 1992, 1998, 2001 and 2006. In April 2006, the Chicago III Expansion Project went into service, adding approximately 130 MMcf/d of transportation capacity from Harper, Iowa to the Chicago market area with the construction of a new 16,000-horsepower compressor station in Iowa and minor modifications to two other compressor stations in Iowa and Illinois. This expansion is fully subscribed by four shippers under long-term firm service transportation agreements with terms ranging from five and one-half to ten years.

Title to Properties

Northern Border Pipeline holds all rights, titles and interests in its pipeline system. With respect to real property, Northern Border Pipeline owns sites for compressor stations, meter stations, pipeline field offices and microwave towers, and derives interests from leases, easements, rights-of-way, permits and licenses from landowners or governmental authorities permitting land use for construction and operation of its pipeline.

Approximately 90 miles of Northern Border Pipeline s system are located within the boundaries of the Fort Peck Indian Reservation in Montana. In 1980, Northern Border Pipeline 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 Pipeline the right to construct and operate its pipeline on certain tribal lands. The pipeline right-of-way lease expires in 2011, although Northern Border Pipeline has 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 Pipeline 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 Bureau of Indian Affairs 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.

Supply

Northern Border Pipeline s customers primary source of natural gas is the Western Canada Sedimentary Basin. In 2006, approximately 85 per cent of the natural gas Northern Border Pipeline transported was produced in Canada. For this reason, the continuous supply of Canadian natural gas is crucial to Northern Border Pipeline s long-term financial condition.

The amount of Canadian natural gas available for export is a major factor affecting the volume of Canadian natural gas transported by Northern Border Pipeline s system. The amount of Canadian natural gas available for export is determined by:

- Canadian natural gas production levels;
- Consumption of natural gas in Canada; and
- storage capacity and inventory levels for Canadian natural gas.

The extent to which Canadian natural gas available for export will be transported on Northern Border Pipeline s system is affected by:

- demand for Canadian natural gas in other U.S. consumer markets;
- available transportation capacity and related market pricing options on other pipelines;

- natural gas from other supply sources that can be transported to the Midwestern U.S.; and

- the natural gas market price spread between Alberta, Canada and the Midwestern U.S., which reflects the relative supply and demand for Canadian natural gas in Canada and in the Midwestern U.S.

Natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana accounted for approximately nine per cent of the natural gas Northern Border Pipeline transported in 2006. The remaining natural gas Northern Border Pipeline transported was synthetic gas produced at the Dakota Gasification plant in North Dakota.

Demand

Demand for natural gas transportation service on Northern Border Pipeline s system is directly related to demand for natural gas in the markets that its customers serve. Factors that may impact demand for natural gas include:

- weather conditions;
- economic conditions;
- government regulation;
- the availability and price of alternative energy sources;
- fuel conservation measures;
- technological advances in fuel economy and energy generation devices;
- new demands for natural gas, such as consumption in ethanol production; and
- the price of natural gas.

Furthermore, factors that may impact demand for natural gas transportation service on Northern Border Pipeline s system include:

- the ability and willingness of natural gas shippers to utilize Northern Border Pipeline s system over alternative pipelines;
- transportation rates; and
- the volume of natural gas delivered to Midwestern U.S. markets from other supply sources and storage facilities.

Northern Border Pipeline s primary exposure to market risk occurs when existing transportation contracts expire and are subject to renegotiation. 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. In addition to general demand for natural gas, regional economic conditions, climate, trends in production, available pipeline capacity and natural gas storage inventories in each market area can also impact the basis differential and affect demand for transportation service on Northern Border Pipeline s system.

Seasonality

Demand for natural gas is seasonal. In the natural gas industry, winter season is considered to be during the months of November through March. Summer season is considered to be April through October. The peak summer season for electric power generation is generally during July, August and September.

Weather conditions throughout the U.S. can significantly impact regional natural gas supply and demand. The Western U.S. market is sensitive to precipitation levels which impact hydroelectric power generation. During the summer, high temperatures combined with low hydroelectric power generation levels can increase demand for Canadian natural gas in the Western U.S. markets and shift supply away from Northern Border Pipeline s system. In the Midwestern U.S., the current pipeline infrastructure is designed to meet the region s peak winter heating demand loads. Moderate winter and summer temperatures can lead to the decline in the demand for Northern Border Pipeline s service due to reduced demand for natural gas.

Northern Border Pipeline s system capacity that is contracted under long-term firm service transportation agreements is not impacted by seasonal throughput variations. The portion of Northern Border Pipeline s capacity that is contracted under short-term (less than one year) transportation agreements is subject to seasonal variations. Northern Border Pipeline s rate case settlement established seasonal rates for short-term service of less than one year, and provides for higher maximum rates during anticipated peak usage periods and lower maximum rates during anticipated periods of reduced demand. Approximately 40 per cent of Northern Border Pipeline s design capacity was contracted on a short-term basis in 2006.

Natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric power generation users. Northern Border Pipeline does not own any natural gas storage facilities. According to the Energy Information Administration (EIA), in 2006, residential, commercial and electric power generation users consumed 67 per cent of the total natural gas volume delivered. Industrial users, who consumed the remaining 33 per cent, demand a steady load of natural gas to operate their facilities but will turn to alternative energy sources when it is not economical to use natural gas.

Customers

Northern Border Pipeline serves Midwestern U.S. markets for customers located throughout North America. Northern Border Pipeline s customers include natural gas producers, marketers, industrial facilities, local distribution companies and electric power generating plants.

For the year ended December 31, 2006, two customers accounted for more than 10 per cent of Northern Border Pipeline s revenue as follows:

Customer	Per cent of Total Revenue
BP Canada Energy Marketing Corp.	21
Cargill Inc.	14

Additional information about these customers is included in Note 5 of Northern Border Pipeline s Financial Statements.

Competition

Competition among natural gas pipelines is based primarily on transportation charges and proximity to natural gas supply areas and markets. Northern Border Pipeline s system competes with other pipelines that transport Western Canadian natural gas to markets in the West, Midwest and East in North America, including TransCanada Pipeline and Alliance Pipeline. Northern Border Pipeline also competes with other pipelines that provide the markets it serves with access to natural gas storage facilities, alternate sources of supply, such as the Rockies, the Mid-Continent, the Permian Basin and the Gulf Coast, and LNG.

Contracting

Northern Border Pipeline contracted 97 per cent of its design capacity on a firm basis in 2006, some of which was sold at a discount to maximize overall revenue on the Port of Morgan, Montana to Harper, Iowa portion of the pipeline. As of January 31, 2007, 72 per cent of Northern Border Pipeline s design capacity was contracted on a firm basis through December 31, 2007. The weighted average life of Northern Border Pipeline s contracts was 1.8 years as of January 31, 2007.

Environmental and Safety Matters

Northern Border Pipeline s operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment. Failure to comply with these laws and regulations can result in substantial penalties, enforcement actions and remedial liabilities. Although Northern Border Pipeline believes its operations and facilities are in compliance in all material respects with applicable environmental laws and safety regulations, it cannot provide any assurances that compliance with current and future laws and regulations will not have a material adverse effect on its financial position or results of operations.

Pipeline Safety Northern Border Pipeline is subject to U.S. Department of Transportation pipeline integrity management regulations. The Pipeline Safety Improvement Act 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. Northern Border Pipeline is on schedule to meet the required assessment of 50 per cent of the highest priority high consequence areas by the end of 2007.

Air and Water Emissions The federal Clean Air Act, the federal Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the U.S. Under the Clean Air Act, a federal operating permit is required for sources of significant air emissions. Northern Border Pipeline may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants discharged in U.S. water. Although Northern Border Pipeline cannot provide any assurances, it believes that it is in compliance with state and federal requirements related to these regulations.

Employees

Northern Border Pipeline does not directly employ any of the persons responsible for managing or operating the partnership or for providing it with services related to its day-to-day business affairs. ONEOK Partners GP will continue to provide administrative, operating and management services to Northern Border Pipeline under an operating agreement through March 31, 2007. ONEOK Partners GP also operates other interstate natural gas pipelines, including Midwestern Gas Transmission Company, Viking Gas Transmission Company and Guardian Pipeline, L.L.C. As of December 31, 2006, ONEOK Partners GP had 324 employees. ONEOK Partners GP s employees are not represented by a labor union nor covered by a collective bargaining agreement. Effective April 1, 2007, TransCan will become Northern Border Pipeline s operator under a new operating agreement. TransCanada has advised Northern Border Pipeline that it will retain approximately 135 individuals who currently operate Northern Border Pipeline s system or provide administrative and management services and will continue to operate Northern Border Pipeline as employees of TransCanada beginning April 1, 2007. These employees are currently employed by ONEOK Partners GP, Northern Border Pipeline s current operator.

BUSINESS OF TUSCARORA GAS TRANSMISSION COMPANY

Tuscarora is a Nevada general partnership formed in 1993. TC Tuscarora ILP owns or controls a 99 per cent general partner interest in Tuscarora, while TCPL Tuscarora Ltd. owns the remaining one per cent general partner interest.

The general partners of Tuscarora are TC Tuscarora ILP, a direct subsidiary of TC PipeLines, Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources and TCPL Tuscarora Ltd., an indirect wholly-owned subsidiary of TransCanada.

Tuscarora is managed by a Management Committee that determines the policies of, has authority over the affairs of, and approves the actions of Tuscarora. The Management Committee participates in the management of the construction, maintenance and operation of the Tuscarora pipeline system. Under the Tuscarora partnership agreement, voting power on the Management Committee is allocated 99 per cent to TC PipeLines and one per cent to TCPL Tuscarora Ltd.

Recent Developments

Change in Ownership On December 19, 2006, the Partnership acquired an additional 49 per cent general partnership interest in Tuscarora for approximately $99.9 million, subject to closing adjustments. In connection with this transaction, a subsidiary of TransCanada became the operator of Tuscarora, which was previously operated by an affiliate of Sierra Pacific Resources. Since December 1, 2002, TransCanada has been under contract to provide gas control services for the Tuscarora pipeline system, including monitoring and control of the compressor units, as well as emergency call out functions and other operational co-ordination.

Cost and Revenue Study In accordance with a letter agreement executed on September 25, 2001 with the Public Utilities Commission of Nevada (PUCN), Tuscarora had an obligation to file a cost and revenue study with the FERC, within a reasonable timeframe following the third anniversary of the in-service date of its 2002 expansion project. The project was placed into service on December 1, 2002. As a result of that requirement, Tuscarora and the PUCN entered into settlement discussions with respect to a potential rate adjustment. On April 26, 2006 the PUCN approved a settlement with Tuscarora. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006. This is a 17 per cent reduction to the previous rate of $0.4811/dth-day, or an approximate $5 million reduction in Tuscarora s annual revenues. In addition, the settlement results in a moratorium on all rate actions before the FERC by any party to the settlement for a period of 48 months to May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate. There is no requirement to file a cost and revenue study or rate case at the end of the moratorium period. The settlement also terminates the September 2001 requirement for Tuscarora to file a cost and revenue study. All firm shippers signed on with the agreement settlement. The settlement was approved by the FERC on July 3, 2006. A compliance filing was made July 7, 2006 for the new tariffs, which were effective as of June 1, 2006. Approval for this filing was received on August 7, 2006.

Tuscarora s Pipeline System

Tuscarora owns a 240-mile, 20-inch diameter, U.S. interstate pipeline system with a subscribed capacity of approximately 180 MMcf/d that originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation, a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs southeast through northeastern California and northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, northern California and northwestern Nevada. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power, a subsidiary of Sierra Pacific Resources.

Operating revenue is derived from the transportation of natural gas. The maximum rates that Tuscarora may charge are established in a FERC proceeding known as a rate case. Tuscarora s tariff specifies the maximum rates and the general terms and conditions for natural gas transportation service on its pipeline. 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 that include the recovery of Tuscarora s cost-based investment, operating expenses and a reasonable return for its investors. The tariff also allows for services to be provided under negotiated and discounted rates. Once maximum rates are set in a rate case, Tuscarora is not permitted to adjust its rates to reflect changes in costs or contract demand until a new rate case is filed and approved by the FERC. As a result, Tuscarora s earnings and cash flow depend on costs incurred, contracted capacity and transportation path, the volume of gas transported and its ability to sell capacity at acceptable rates.

Tuscarora generates revenues from individual transportation contracts with shippers that provide for the receipt and delivery of natural gas at points along the Tuscarora pipeline system. Tuscarora s transportation rates are based on its cost of service as approved by the FERC. Tuscarora s cost of service includes administrative and operating costs, depreciation and amortization, taxes other than income taxes, an allowance for income taxes and a regulated return on capital employed.

Title to Properties

Tuscarora holds all rights, titles and interests in its pipeline system. Tuscarora owns all of its material equipment and personal property and leases office space in Reno, Nevada. With respect to real property, Tuscarora s ownership falls into two basic categories: (a) parcels which it owns in fee; and (b) parcels where its interest derives from leases, easements, grants, permits or licenses from landowners or governmental authorities permitting the use of the land for the construction and operation of its pipeline system.

The Tuscarora pipeline system was constructed in 1995 and was placed into service in December 1995. In January 2001, Tuscarora completed construction of the Hungry Valley lateral, a 14-mile, 16-inch pipeline extension that serves as Tuscarora s second connection into Reno, Nevada. On December 1, 2002, Tuscarora completed and placed into service an expansion of its pipeline system. This expansion consisted of two compressor stations and an 11-mile pipeline extension from a point near the previous terminus of the Tuscarora pipeline system near Reno, Nevada to Wadsworth, Nevada. The expansion increased Tuscarora s contracted capacity from 127 MMcf/d to approximately 180 MMcf/d. The new capacity was contracted under long-term firm transportation contracts ranging from ten to fifteen years from the in-service date. Tuscarora completed construction of the Barrick Lateral, a 0.5 mile lateral that provides transportation service to a new electric generation customer located near Tracy, Nevada. The construction of the lateral was completed and commissioned for service to Barrick Goldstrike on August 1, 2005.

Competition

Tuscarora s competitive position is dependent on the continued availability of commercially attractive Western Canadian natural gas for import into the U.S. and on the level of demand for Western Canadian natural gas in the markets the Tuscarora pipeline system serves. Shippers of natural gas from the Western Canada Sedimentary Basin have other options for transporting Canadian natural gas to the U.S., including transportation on pipelines eastward in Canada or to markets on the west coast of the U.S. and Canada. Similarly, natural gas produced in the U.S. serves the same markets as Tuscarora in northern Nevada.

Contracting

Tuscarora has firm transportation contracts for over 95 per cent of its available contracted capacity, including contracts held by Sierra Pacific Power Company (Sierra Pacific Power), a subsidiary of Sierra Pacific Resources, for 69 per cent of the total available capacity, the majority of which expires on October 31, 2017. As of December 31, 2006, the weighted average contract life on the Tuscarora pipeline system was approximately 11.4 years. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power. Along its route, deliveries are made in Oregon, northern California and northwestern Nevada.

Environmental and Safety Matters

Tuscarora s operations are subject to extensive federal, state and local laws and regulations governing safety and the discharge of materials into the environment or otherwise relating to the protection of the environment. Tuscarora s operations and facilities comply in all material respects with applicable U.S. environmental and safety regulations. Failure to comply with these laws and regulations can result in substantial penalties, enforcement actions and remedial liabilities. Although Tuscarora advises that it believes its operations and facilities are in compliance in all material respects with applicable environmental laws and safety regulations, it cannot provide any assurances that compliance with current and future laws and regulations will not have a material adverse affect on its financial position or results of operations.

Pipeline Safety Tuscarora is subject to U.S. Department of Transportation integrity management regulations. The Pipeline Safety Improvement Act 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. Tuscarora has met its obligations for review of high consequence areas in 2006 and is not aware of any areas requiring further action at this time.

A U.S. Department of Transportation audit was completed in 2005, and there were no findings of non-compliance.

Air and Water Emissions The Clean Air Act and the Clean Water Act impose restrictions and controls regarding the discharge of pollutants into the air and water in the U S. Under the Clean Air Act, a federal operating permit is required for sources of significant air emissions. Tuscarora may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants discharged in U.S water. Although Tuscarora advises it cannot provide any assurances related to future impacts, it believes that it is in compliance with state and federal requirements related to these regulations.

Employees

Tuscarora does not directly employ any of the persons responsible for managing or operating the partnership or for providing it with services related to its day-to-day business affairs. A subsidiary of Sierra Pacific Resources was the operator until December 19, 2006. On acquisition of the additional 49 per cent general partnership interest, a subsidiary of TransCanada became the operator of Tuscarora.

GOVERNMENT REGULATION

Great Lakes, Northern Border Pipeline, and Tuscarora (together our pipeline systems) are regulated under the Natural Gas Act and Natural Gas Policy Act, which give FERC jurisdiction to regulate virtually all aspects of its business, including:

- transportation of natural gas;
- rates and charges;
- terms of service including creditworthiness requirements;
- construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- the acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- standards of conduct business relations with certain affiliates.

Rate Case, Great Lakes Great Lakes last rate settlement expired on October 31, 2005 with no requirement to file a new rate proceeding or settlement.

Rate Case, Northern Border Pipeline As required by the provisions of the settlement of Northern Border Pipeline s 1999 rate case, on November 1, 2005, it filed a rate case with the FERC. In December 2005, the FERC issued an order that identified issues that were raised in the proceeding and accepted the proposed rates, but suspended their effectiveness until May 1, 2006. The new rates were collected subject to refund from May 1, 2006 through September 30, 2006. Based on the settlement discussed below, Northern Border Pipeline refunded $10.8 million to its customers in the fourth quarter of 2006.

On September 18, 2006, Northern Border Pipeline filed a stipulation and agreement which documented the settlement reached between Northern Border Pipeline and its participant customers and was supported by the FERC trial staff. The uncontested settlement was approved by the FERC on November 21, 2006.

The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border Pipeline s system. Beginning in 2007, overall rates were reduced, compared with rates prior to the filing, by approximately five per cent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dth is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The factors used in calculating depreciation expense for transmission plant increased from 2.25 per cent to 2.40 per cent. 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 Northern Border Pipeline files a rate case within six years.

Cost and Revenue Study, Tuscarora In accordance with a letter agreement executed on September 25, 2001 with the Public Utilities Commission of Nevada (PUCN), Tuscarora had an obligation to file a cost and revenue study with the FERC, within a reasonable timeframe following the third anniversary of the in-service date of its 2002 expansion project. The project was placed into service on December 1, 2002. As a result of that requirement, Tuscarora and the PUCN entered into settlement discussions with respect to a potential rate adjustment. On April 26, 2006 the PUCN approved a settlement with Tuscarora. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006. This is a 17 per cent reduction to the previous rate of $0.4811/dth-day, or an approximate $5 million reduction in Tuscarora s annual revenues. In addition, the settlement results in a moratorium on all rate actions before the FERC by any party to the settlement for a period of 48 months to May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate. There is no requirement to file a cost and revenue study or rate case at the end of the moratorium period. The settlement also terminates the September 2001 requirement for Tuscarora to file a cost and revenue study. All firm shippers signed on with the agreement settlement. The settlement was approved by the FERC on July 3, 2006. A compliance filing was made July 7, 2006 for the new tariffs, which were effective as of June 1, 2006. Approval for this filing was received on August 7, 2006.

Income Tax Allowance In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the rates for partnership interests held by partners with an actual or potential income tax liability. On December 16, 2005, the FERC issued an order (the December 16 Order) in its first case-specific review of the income tax allowance issue, reaffirming its tax allowance policy and directing the pipeline to provide certain evidence necessary to determine the income tax allowance. The FERC s new policy and the December 16 Order have been appealed to the D.C. Circuit Court and rehearing requests have been filed with respect to the December 16 Order. The ultimate outcome of these proceedings could impact how the policy statement is applied to our pipeline systems in future proceedings.

Creditworthiness Standards In June 2005, the FERC adopted a new policy detailing creditworthiness standards for interstate pipelines. The FERC s policy states that pipelines must use objective criteria to determine a shipper s creditworthiness, utilizing a standard set of documents that shippers are required to provide. For current shippers on existing facilities, the FERC reiterated its traditional policy of permitting no more than the equivalent of three months of reservation charges as security. For new mainline constructions, the FERC will continue its policy of permitting larger security requirements that reasonably reflect the risk of the project. The issue of whether a pipeline may justify security in an amount greater than three months of reservation charges was voluntarily remanded to the FERC for further consideration. In an Order on Voluntary Remand issued in November 2006, the FERC reaffirmed its finding that interstate pipelines should not be allowed to require more than three months security from shippers.

Negotiated Rate Policy In January 2006, the FERC issued an order revising its negotiated rate policy to allow the use of basis differentials, without a tariff rate revenue cap, in determining negotiated rates. The use of basis differentials for negotiated rates was previously prohibited because the FERC believed that such a pricing mechanism could give pipelines an incentive to withhold capacity and manipulate the natural gas markets by widening the basis between indexes. The FERC found this policy to be overly restrictive, given the benefits that such a pricing mechanism yields. Since negotiated rate transactions must be filed and approved by the FERC and such filings give all parties an opportunity to comment, any allegations of attempted manipulation would be investigated. Comments were filed seeking clarification or conditions to the implementation of this policy. In March 2006, the FERC dismissed the requests for rehearing and denied the requests for clarification.

Natural Gas Quality and Interchangeability In June 2006, the FERC issued a policy statement detailing its policy on natural gas quality and interchangeability. The FERC adopted a relatively flexible policy that promotes case-by-case negotiation. The FERC s policy embodies five principles: 1) only natural gas quality and interchangeability specifications contained in a FERC-approved gas tariff can be enforced; 2) pipeline tariff provisions on gas quality and interchangeability need to be flexible to allow pipelines to balance safety and reliability concerns with the importance of maximizing supply, as well as recognizing the evolving nature of the science underlying gas quality and interchangeability specifications; 3) pipelines and their customers should develop gas quality and interchangeability specifications based on technical requirements; 4) in negotiating technically based solutions, pipelines and their customers are strongly encouraged to use the Natural Gas Council Plus interim guidelines as a common reference point for resolving gas quality and interchangeability issues; and 5) to the extent pipelines and their customers cannot resolve disputes over gas quality and interchangeability, those disputes can be brought before the FERC to be resolved on a case-by-case basis.

Energy Policy Act of 2005 In August 2005, the Energy Policy Act of 2005 was signed into law addressing a wide range of issues, including many that impact the oil and gas industry. The Energy Policy Act of 2005: 1) provides that the FERC will be the lead agency and creates a common record for review of federal permitting decisions associated with interstate gas pipeline projects authorized under the Natural Gas Act; 2) makes it unlawful to engage in market manipulation under the Natural Gas Act; 3) authorizes the FERC to issue market transparency rules that provide greater information about natural gas prices; and 4) increases criminal penalties that may be assessed under the Natural Gas Act and the Natural Gas Policy Act to up to $1 million per violation, and increases civil penalties under the Natural Gas Act to up to $1 million per day for violations as long as they continue. In October 2006, the FERC issued Order No. 687 that implements the provisions of the Energy Policy Act of 2005 requiring the FERC to coordinate environmental reviews and the issuance of all federal authorizations for natural gas infrastructure proposals with other federal and state agencies, and to maintain a consolidated federal record for judicial appeal and review. Under the final rule, which was effective December 28, 2006, the FERC will act as lead agency for environmental reviews and will establish a schedule pursuant to which federal agencies, as well as state agencies acting under federally delegated authority, will reach final regulatory decisions necessary for the approval of natural gas infrastructure projects under Section 7 of the Natural Gas Act. The deadline for agencies final decisions will be 90 days after the FERC staff issues either an environmental assessment or an environmental impact statement. The 90 day deadline will not apply if an agency s deadline is otherwise determined by federal law.

Energy Affiliates In November 2003, the FERC adopted revised standards of conduct which govern the relationships between regulated interstate natural gas pipelines and their energy affiliates. The new standards of conduct were designed to prevent interstate natural gas pipelines from giving any undue preference to their energy affiliates and ensure that transmission service is provided on a nondiscriminatory basis. Subsidiaries of ONEOK Partners and ONEOK Inc., including ONEOK Energy Services Company, LP (ONEOK Energy), and subsidiaries of TransCanada were deemed to be Northern Border Pipeline s energy affiliates under the standards of conduct in effect for the majority of 2006. In November 2006, the United States Court of Appeals for the District of Columbia vacated the FERC s order regarding standards of conduct for energy affiliates of natural gas pipelines and remanded the matter back to the FERC. On January 9, 2007, the FERC issued Order No. 690, Standards of Conduct for Transmission Providers (the Interim Rule) as the Commission s interim response to the Appeals Court decision. The Interim Rule reduced the application of the standards of conduct for interstate natural gas pipelines to the relationship between the pipelines and their marketing affiliates as defined in the FERC s rules that were in effect prior to the current regulations and made certain other revisions that were subject to the appeal. Requests for clarifications and in the alternative rehearing of the Interim Rule have been filed. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking, which if accepted as the final rule, will make permanent the Interim Rule s applicability of the standards of conduct to govern the relationship between interstate natural gas pipelines and their marketing affiliates.

Market Manipulation In January 2006, the FERC issued a final rule making it unlawful for any entity subject to its jurisdiction that directly or indirectly purchases or sells natural gas, transportation services or electric energy to defraud, using any device, scheme or artifice; make untrue statements of a material fact or omit a material fact; or engage in any act, practice or course of business that operates as a fraud. The maximum civil penalty under these statutes is $1 million per day, per violation.

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 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 in this Form 10-K filing are forward-looking and relate to, among other things, anticipated financial performance, 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, forec 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 under Item 1A. Risk Factors , which could cause TC PipeLines 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.

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Risks Inherent in Our Business

We are dependent on our pipeline systems and may not be able to generate sufficient cash from the distributions from Great Lakes, Northern Border Pipeline and the operations of Tuscarora to enable us to pay the expected quarterly distribution on TC PipeLines common units.

The actual amount of cash we will have available to distribute to our common unitholders will depend upon numerous factors relating to each of our pipeline systems businesses, most of which are beyond our control and the control of our general partner, including:

- the amount of cash distributed to us from our pipeline systems;
- the tariff and transportation charges collected by our pipeline systems for transportation services on their pipeline systems;
- the ability to recontract capacity for maximum transportation rates as existing contracts terminate;
- the amount of cash required to be contributed by us to our pipeline systems in the future;
- the success of our pipelines competing with other pipeline systems;
- increases in our pipeline systems maintenance and operating costs; and
- expansion costs related to these systems.

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

- the amount of cash set aside and the adjustment in reserves made by our general partner in its sole discretion;
- the amount of our operating costs, including payments to our general partner;
- the required principal and interest payments on our debt;
- the cost of acquisitions, including related debt service payments; and
- our issuance of debt and equity securities.

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

As of December 31, 2006, each of our pipeline systems has customers that account for more than ten per cent of its revenue. Sierra Pacific Power, a wholly-owned subsidiary of Sierra Pacific Resources, is Tuscarora s largest shipper, with firm contracts for approximately 69 per cent of its capacity. Sierra Pacific Resources and Sierra Pacific Power have below-investment grade credit ratings. If any of the significant shippers on our pipeline systems fail to meet their contractual obligations, our ability to make cash distributions to our unitholders at current levels may be adversely affected.

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

Demand for natural gas is seasonal. Capacity that is contracted under firm service transportation agreements is not impacted by seasonal throughput variations but when transportation agreements expire, seasonal demand can impact Great Lakes and Northern Border Pipeline s ability to recontract firm service transportation capacity. Accordingly, throughput on Great Lakes and Northern Border Pipeline have and may continue to experience seasonal fluctuations and discounting of rates may be required to maximize revenue.

The renewal or replacement of existing contracts with customers of Great Lakes and Northern Border Pipeline depends on a number of factors beyond Great Lakes and Northern Border Pipeline s control, including:

- the supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply in the U.S.;
- competition from other pipelines; and
- the price of, and demand for, natural gas in markets served by the Great Lakes and Northern Border Pipeline systems.

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Because of ongoing changes in these factors and customers ability to adjust to changing market conditions, Great Lakes and Northern Border Pipeline may sell a significant portion of available capacity on a short-term basis. The weighted average life of Great Lakes and Northern Border Pipeline s contracts has generally declined over time. Additionally, if the forward natural gas basis differentials do not support maximum rates, they may sell portions of its capacity at discounted rates. Any inability by Great Lakes and Northern Border Pipeline to renew existing contracts at maximum rates or at all may have an adverse impact on their revenues, and, as a result, cash distributions made to us.

Tuscarora competes in the northern Nevada natural gas transmission market with Paiute, owned by Southwest Gas Co. of Las Vegas, Nevada. The Paiute pipeline interconnects with Northwest Pipeline Corp. at the Nevada-Idaho border and transports natural gas from British Columbia and the U.S. Rocky Mountain Basin to the northern Nevada market.

TransCanada s main pipeline systems transport natural gas from the same natural gas reserves in Western Canada that are used by our pipeline systems customers. TransCanada is not prohibited from actively competing with our pipeline systems for the transport of Western Canadian natural gas.

Our pipeline systems transportation rates are subject to review and possible adjustment by federal regulators.

Our pipeline systems are subject to extensive regulation by the FERC, which regulates most aspects of their business, including their respective transportation rates. Under the Natural Gas Act, interstate transportation rates must be just and reasonable and not unduly discriminatory. Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our pipeline systems ability to establish rates, or to charges rates that would cover future increase in their costs, 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.

The long-term financial conditions of our pipeline systems, and as a result, of TC PipeLines, are dependent on the continued availability of Western Canadian natural gas for import into the U.S.

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, or the lack of available capital for these projects could adversely affect the development of additional reserves and the production, gathering, storage, pipeline transmission, import and export of natural gas supplies.

In addition, the internal demand for Canadian natural gas may increase, as a result of increased demand for 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 import to the U.S. In the longer term, a portion of the Alberta hub gas supply may come from proposed gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada and from the continued growth of coal bed methane projects. Cancellation or delays in the construction of such pipelines or such projects could adversely affect us. If the availability of Alberta hub natural gas were to decline, existing shippers on our pipeline systems 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.

Our pipeline systems businesses depend in part on the level of demand for Western Canadian natural gas in the markets the pipeline systems serve. If demand for Western Canadian natural gas decreases, shippers may not enter into or renew contracts.

Our pipeline systems businesses depend in part on the level of demand for Western Canadian natural gas in the markets the pipeline systems serve. The volumes of natural gas delivered to these markets from other sources affect the demand for both Western Canadian natural gas and use of these pipeline systems. Demand for Western Canadian natural gas also influences the ability and willingness of shippers to use our pipeline systems to meet the demand that these pipeline systems serve.

In addition, existing customers may not extend their contracts if the cost of delivered natural gas from other producing regions into the markets served by our pipeline systems is lower that the cost of natural gas delivered by our pipeline systems. Our pipeline systems may be unable to find additional customers to replace the lost demand or transportation fees. 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 revenues and results of operations.

If the FERC requires that our pipeline systems tariff be changed, their respective cash flows may be adversely affected.

Our pipeline systems are subject to extensive regulation by the FERC. The FERC s regulatory authority is not limited to but extends to matters including:

- transportation of natural gas;
- rates and charges;
- terms of service including creditworthiness requirements;
- construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- the acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- standards of conduct business relations with certain affiliates.

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

- the likely 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.

The outcome of future proceedings before the FERC may adversely affect the amount of cash our pipeline systems is able to distribute to us.

We may be unable to cause Great Lakes or Northern Border Pipeline to take or not to take certain actions unless the other owner agrees.

The major policies of Northern Border Pipeline and Great Lakes are established by the Management Committee.

Northern Border Pipeline 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. 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 Pipeline to take or not to take certain actions, even though those actions may be in the best interest of us or Northern Border Pipeline.

Great Lakes Management Committee consists of six members, three of whom are designated by us and three of whom are designated by TransCanada. All decisions by the Management Committee require unanimous consent. An Executive Committee which consists of three members: one Partnership Committee Member, one TransCanada Committee Member and the Great Lakes President, a non-voting member. The Executive Committee has all of the powers of the Management Committee in the management of Great Lakes business. Because of

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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.

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. The amount they may collect from customers decreases as the rate base declines as a result of, among other things, depreciation and amortization.

Our pipeline systems pipeline integrity program may impose significant costs and liabilities.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as high consequence areas. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of the pipeline testing and any subsequent repairs found to be necessary. 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 the continued safe and reliable operation of their pipelines.

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

As of December 31, 2006, Great Lakes, Northern Border Pipeline, Tuscarora had $450 million, $599.8 million and $71.1 million of debt outstanding, respectively. This substantial level of debt could have important consequences to Great Lakes, Northern Border Pipeline 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 will make them more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

- their debt level may limit our 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 our 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 Pipeline 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, our third party credit facility requires us to maintain certain financial ratios and contains restrictions on incurring additional debt and making distributions to partners.

Any future refinancing of our pipeline systems or our existing indebtedness or any new indebtedness could have similar or greater restrictions.

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 record profits.

Our pipeline systems operations are regulated by federal and state agencies responsible for environmental protection and operational safety.

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. If our pipeline systems are not able to recover these costs, cash distributions to unitholders could be adversely affected.

Our pipeline systems operations are subject to operational hazards and unforeseen interruptions, including natural disasters, adverse weather, accidents or other events beyond their control. A casualty occurrence might result in a loss of equipment or life, as well as injury and extensive property or environmental damage.

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

As a result of acquisitions in 2006, TransCanada, or a wholly-owned subsidiary, is or will become operator of all our pipeline systems. We do not presently have sufficient stand-alone management resources to operate without services provided by TransCanada. Further, we would not be able to evaluate potential acquisitions and successfully complete acquisitions without TransCanada s resources.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

We have significant exposure to increases in interest rates. As of December 31, 2006, TC PipeLines had approximately $397.0 million of debt, all of which was at 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, 2006, approximately half of the variable interest rate exposure related to the Partnership s $397.0 million of debt was mitigated by fixed interest rate swap arrangements. Subsequent to year end, the partnership borrowed another $126 million from its senior Credit Facility to finance the acquisition of Great Lakes. Also, an additional $100 million of debt was hedged by interest rate swaps.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular 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.

Risks Inherent in an Investment in the Partnership

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.

TC PipeLines GP and its affiliates have limited fiduciary responsibilities and may have conflicts of interest with respect to our partnership.

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:

- decisions of TC PipeLines GP regarding the amount and timing of asset purchases and sales, cash 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 our 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 employees of TC PipeLines GP and its affiliates, and

- TransCanada, or a wholly-owned subsidiary, is and will be the operator of our pipeline systems. This operator role along with their ownership interests in Tuscarora and Great Lakes, may put TransCanada in a position to have to make decisions that may conflict as operator and owner of these systems.

The Partnership s indebtedness may limit its ability to borrow additional funds, make distributions or capitalize on business opportunities.

As of December 31, 2006, the Partnership had $397 million of debt outstanding. 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, 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.

Unitholders will have limited voting rights and will 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 will have only limited voting rights on matters affecting our business. Unitholders will 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 approximately 32 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 existing unitholders interest.

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 TC PipeLines and dilute the interests of unitholders in distributions by TC PipeLines. 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.

Issuance of additional common units will increase the risk that we will be unable to pay the full minimum quarterly distribution on all common units.

Our ability to pay the full minimum quarterly distribution on all the common units may be reduced by any increase in the number of outstanding common units. Additional common units would be issued:

- upon the conversion of the general partner interests and the incentive distribution rights as a result of the withdrawal of the general partner; or

- as a result of future issuances of common units.

Any of these actions 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.

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, 2006 we paid fees and reimbursements to our general partner in the amounts of $1.2 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.

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 approximately 30.7 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, which it may assign to any of its affiliates or us, to acquire all, but not less than 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.

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:

- TC PipeLines 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 TC PipeLines business,

then unitholders could be held liable in some circumstances for TC PipeLines obligations to the same extent as a general partner. In addition, under some circumstances a unitholder may be liable to TC PipeLines for the amount of a distribution for a period of three years from the date of the distribution.

Without the consent of each unitholder, Great Lakes, Northern Border Pipeline or Tuscarora might be converted into a corporation, which would result in Great Lakes, Northern Border Pipeline 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 Pipeline or Tuscarora as a partnership and some other conditions are satisfied, the business and assets of Great Lakes, Northern Border Pipeline 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 Pipeline or Tuscarora being subject to corporate income taxes and would likely be materially adverse to its, and, therefore, our, results of operations and financial condition.

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 consist of a 46.45 per cent general partner interest in Great Lakes, 50 per cent general partner interest in Northern Border Pipeline and 98 per cent general partner interest in Tuscarora. We could be deemed to be an investment company under the Investment Company Act if these general partner 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.

Our credit facilities may limit our ability to borrow additional funds or capitalize on business opportunities.

Our credit facilities contain restrictive covenants that may prevent us from engaging in certain transactions that we deem beneficial. These agreements require us to comply with various affirmative and negative covenants including restrictions on:

- entering into mergers, consolidations and sales of assets;
- granting liens; and
- material amendments to the TC PipeLines partnership agreement.

In addition, our third party credit facility requires us to maintain certain financial ratios and contains restrictions on:

- incurring additional debt; and
- distributions to partners.

The instruments governing any future debt may contain similar restrictions.

Tax Risks

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 matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35 per cent, distributions would generally be taxed again to unitholders as corporate distributions, and no income, gains, losses, deductions or credits would flow through to them. 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 law 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.

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 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 the 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 will 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 gain or loss 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 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.

Investors other than individuals that are U.S. residents may have adverse tax consequences from owning common units.

Investment in common units by tax-exempt entities, regulated investment companies and foreign persons raises issues unique to these persons. For example, virtually all of our income allocated to organizations 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. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships as qualifying income to a regulated investment company. However, this legislation is only effective for taxable years beginning after October 22, 2004, the date of enactment. For taxable years beginning prior to the date of enactment, very little of our income will be qualifying income to a regulated investment company. Distributions to foreign persons will be reduced by withholding taxes. Foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We have registered as a tax shelter. This may increase the risk of an IRS audit of TC PipeLines or a unitholder.

We have registered as a tax shelter with the Secretary of the Treasury. Prior to enactment of recent legislation, the IRS required that some types of entities, including some partnerships, register as tax shelters in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1 per cent interest in us has a very limited right to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in unitholders tax returns and may lead to audits of their tax returns and adjustments of items unrelated to us. Unitholders would bear the cost of any expenses incurred in connection with an examination of their personal tax return.

We treat a purchaser of common units as having the same tax benefits as the seller. A successful IRS challenge could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization conventions that 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.

The sale or exchange of 50 per cent or more of our capital and profits interests 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 as a result of an investment in 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. 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. It is unitholders responsibility to file all required United States 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

TC PipeLines does not hold the right, title or interest in any properties.

Properties of Great Lakes Gas Transmission Limited Partnership

See Item 1. Business - Business of Great Lakes Gas Transmission Limited Partnership for a description of Great Lakes properties, their utilization, and how each property is held.

Properties of Northern Border Pipeline Company

See Item 1. Business - Business of Northern Border Pipeline Company for a description of Northern Border Pipeline s properties, their utilization, and how each property is held.

Properties of Tuscarora Gas Transmission Company

See Item 1. Business - Business of Tuscarora Gas Transmission Company for a description of Tuscarora s properties, their utilization, and how each property is held.

Item 3. Legal Proceedings

TC PipeLines is not currently a party to any material legal proceedings.

Great Lakes is not currently a party to any material legal proceedings.

Tuscarora is not currently a party to any material legal proceedings.

Notice of Rate Change of Northern Border Pipeline Company, Federal Energy Regulatory Commission, Docket No. RP06-72-000. As required by the provisions of the settlement of Northern Border Pipeline s 1999 rate case, on November 1, 2005, Northern Border Pipeline filed a rate case with the FERC. On September 18, 2006, Northern Border Pipeline filed a stipulation and agreement which documented the settlement reached between it and its participant customers and was supported by the FERC trial staff. The uncontested settlement was approved by the FERC on November 21, 2006. Northern Border Pipeline refunded $10.8 million to its customers during the fourth quarter of 2006.

The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border Pipeline s system. Beginning in 2007, overall rates were reduced, compared with rates prior to the filing, by approximately five per cent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dth is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The factors used in calculating depreciation expense for transmission plant increased from 2.25 per cent to 2.40 per cent. 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 Northern Border Pipeline file a rate case within six years.

Various other legal actions that have arisen in the ordinary course of business are pending. Northern Border Pipeline believes that the resolution of these issues will not have a material adverse impact on its results of operations or financial position.

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, 2006.

PART II

Item 5. Market for Registrant s Common Units, Related Security Holder Matters and Issuer Purchases of Equity Securities

The common units representing limited partner interests in the Partnership were issued pursuant to an initial public offering on May 28, 1999. The common units are quoted on the NASDAQ Global Market 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 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	
	High		Low		Declared per unit	
2006						
First Quarter	**$**	**35.14**	**$**	**32.60**	**$**	**0.575**
Second Quarter	**$**	**34.65**	**$**	**31.54**	**$**	**0.575**
Third Quarter	**$**	**33.50**	**$**	**30.41**	**$**	**0.575**
Fourth Quarter	**$**	**36.00**	**$**	**30.00**	**$**	**0.600**
2005						
First Quarter	$	40.60	$	35.50	$	0.575
Second Quarter	$	36.22	$	31.20	$	0.575
Third Quarter	$	35.24	$	32.12	$	0.575
Fourth Quarter	$	34.91	$	31.73	$	0.575

As of March 1, 2007, there were 107 registered holders of common units and approximately 15,000 beneficial owners of common units, including common units held in street name.

The Partnership currently has 34,856,086 common units outstanding, of which 24,142,935 are held by the public, 8,678,045 are held by TransCan Northern Ltd., a wholly-owned subsidiary of TransCanada, and 2,035,106 are held by TC PipeLines GP. 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 and the holders of common units (collectively referred to as unitholders) receive the remaining 98 per cent. The general partner is also entitled to incentive distributions as described below. The Partnership s quarterly cash distributions to its unitholders are comprised of 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; or
- provide funds for cash distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

The general partner receives incentive distributions if the amount distributed with respect to any quarter exceeds the minimum quarterly distribution of $0.45 per common unit. Under the incentive distribution provisions, the general partner receives 15 per cent of amounts distributed in excess of $0.45 per common unit, 25 per cent of amounts distributed in excess of $0.5275 per common unit, and 50 per cent of amounts distributed in excess of $0.69 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 2006, the Partnership made cash distributions to unitholders and the general partner that amounted to $43.5 million compared to $43.0 million in 2005. These payments represented $0.575 per common unit in each of the three quarters ended September 30, 2006 and $0.60 per common unit in the fourth quarter ended December 31, 2006. On February 14, 2007, the Partnership paid a cash distribution of $11.3 million to unitholders and the general partner, representing a cash distribution of $0.60 per common unit for the quarter ended December 31, 2006. The distribution was allocated in the following manner: $10.5 million to the holders of common units as of the close of business on January 31, 2007 (including $1.2 million to the general partner as holder of 2,035,106 common units),

$0.6 million to the general partner as holder of incentive distribution rights, and $0.2 million to the general partner in respect of its two per cent general partner interest.

Termination of Subordination Period

At the time of the Partnership s initial public offering in 1999, 2,809,306 subordinated units were issued to the general partner. Pursuant to the partnership agreement one-third of each of the subordinated units converted on August 1, 2002, August 1, 2003 and July 30, 2004. All 2,809,306 subordinated units have been converted into common units held by the general partner and the subordination period has terminated.

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.

TC PIPELINES, LP (millions of dollars, except per unit amounts)	**Year Ended December 31** 2006*	2005	2004	2003	2002
Income Data					
Equity income from investment in Northern Border Pipeline	**56.6**	45.7	50.0	44.5	42.8
Equity income from investment in Tuscarora	**5.9**	7.5	7.5	5.3	4.7
Transmission revenues	**0.9**				
Financial charges, net and other	**(15.8)**	(1.0)	(0.5)	(0.1)	(0.5)
Net income	**44.7**	50.2	55.1	48.0	45.5
Basic and diluted net income per unit	**$ 2.39**	$ 2.70	$ 2.99	$ 2.63	$ 2.50
Cash Flow Data					
Cash distribution paid per unit	**$ 2.325**	$ 2.300	$ 2.275	$ 2.175	$ 2.075
Balance Sheet Data (at December 31)					
Total assets	**777.8**	315.7	332.1	288.1	286.0
Long-term debt (including current maturities)	**468.1**	13.5	36.5	5.5	11.5
Partners equity	**303.9**	301.6	294.9	282.0	273.9

* TC PipeLines 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

As a result of the Partnership s ownership of interests in both Northern Border Pipeline and Tuscarora, the following discusses the results of operations and liquidity and capital resources of TC PipeLines, and those of each Northern Border Pipeline and Tuscarora.

As the acquisition of Great Lakes occurred subsequent to December 31, 2006, the following does not include a discussion of the financial condition and results of operations of Great Lakes.

The following discussions of the financial condition and results of operations of the Partnership, Northern Border Pipeline and Tuscarora should be read in conjunction with the financial statements and notes thereto of the Partnership and Northern Border Pipeline 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 and Northern Border Pipeline. As of December 31, 2006, TC PipeLines interest in Northern Border Pipeline represented approximately 72 per cent of TC PipeLines total assets and for the year ended December 31, 2006 provided approximately 91 per cent of TC PipeLines total equity income. All amounts are stated in U.S. dollars.

OVERVIEW

TC PipeLines was formed in 1998 as a Delaware limited partnership. At December 31, 2006, TC PipeLines owned a 50 per cent general partner interest in Northern Border Pipeline. The remaining 50 per cent general partner interest in Northern Border Pipeline was held by ONEOK Partners, a publicly traded limited partnership that is controlled by ONEOK, Inc.

TC PipeLines also owns or controls a 99 per cent general partner interest in Tuscarora. The Partnership acquired a 49 per cent interest from TCPL Tuscarora Ltd., a wholly-owned indirect subsidiary of TransCanada, in September 2000. An additional 49 per cent was acquired from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, on December 19, 2006. Tuscarora Gas Pipeline Co. continues to hold a one per cent general partner interest and TCPL Tuscarora Ltd., an indirect wholly-owned subsidiary of TransCanada holds the remaining one per cent general partner interest in Tuscarora.

The Partnership s general partner interests in Northern Border Pipeline and Tuscarora represent its only material assets at December 31, 2006. As a result, the Partnership is dependent upon Northern Border Pipeline and Tuscarora for all of its available cash. Northern Border Pipeline represents approximately 91 per cent of TC PipeLines total equity income. For an overview discussing the important factors impacting Northern Border Pipeline s business, see Results of Operations of Northern Border Pipeline Company Northern Border Pipeline s Business Environment.

RESULTS OF OPERATIONS OF TC PIPELINES, LP

The general partner interests in Northern Border Pipeline and Tuscarora were our only material sources of income in 2006; therefore, our results of operations were influenced by and reflect the same factors that influenced the financial results of Northern Border Pipeline and Tuscarora (see Item 1. Business Business of Northern Border Pipeline Company and Business Business of Tuscarora Gas Transmission Company).

Accounting Policies and Estimates

TC PipeLines accounts for its investment in Northern Border Pipeline using the equity method of accounting, as detailed in Notes 2 and 3 to the Partnership s Financial Statements, included elsewhere in this report. 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. TC PipeLines is able to exercise significant influence over its investment in Northern Border Pipeline as evidenced by its representation on Northern Border Pipeline s management committee.

As detailed in Notes 2 and 4 to the Partnership s Financial Statements, included elsewhere in this report, TC PipeLines used the equity method to account for its investment in Tuscarora until December 19, 2006. On this date, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora and, as a result of acquiring a controlling interest in Tuscarora, began to consolidate its operations. The consolidation method of accounting is appropriate where the investor controls the investee.

Cash Distributions from Investments

To supplement our financial statements, we have disclosed cash distributions from investments and have itemized the cash distributions received from our original general partner interests and the increase in cash distributions due to 2006 acquisitions. We have presented this additional information to enhance an investor s understanding of the way that management analyzes the Partnership s financial performance. The segregation of the cash distributions received before and after the impact of 2006 acquisitions provides a comparison of the Partnership s cash flows in 2006 to prior years. 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.

Cash Distributions from Investments (a)

(millions of dollars)	2006	2005	2004	2003	2002
Cash distributions from initial 30% general partner interest in Northern Border Pipeline	**53.7**	60.9	61.7	46.2	49.2
Cash distributions from initial 49% general partner interest in Tuscarora	**7.7**	8.3	7.6	6.2	4.6
	61.4	69.2	69.3	52.4	53.8
Increase in cash distributions due to 2006 acquisitions (b)	**26.7**				
Cash distributions from investments (a)	**88.1**	69.2	69.3	52.4	53.8
Partnership costs (c)	**(18.2)**	(3.0)	(2.4)	(1.8)	(2.0)
Cash distributions from investments net of Partnership costs (c)	**69.9**	**66.2**	**66.9**	**50.6**	**51.8**

(a) Reconciliation of non-GAAP financial measure: Cash distributions from investments is a non-GAAP financial measure which is the sum of equity income from investment in Northern Border Pipeline, equity income from investment in Tuscarora, distributions received in excess of equity income, return of capital from Northern Border Pipeline and return of capital from Tuscarora. It is provided as a supplement to results reported in accordance with GAAP. Management believes that this is a meaningful measure to assist investors in evaluating the Partnership s business performance. Below is a reconciliation of Cash distributions from investments to GAAP financial measures:

(millions of dollars)	2006	2005	2004	2003	2002
Equity income from investment in Northern Border Pipeline	**56.6**	45.7	50.0	44.5	42.8
Equity income from investment in Tuscarora	**5.9**	7.5	7.5	5.3	4.7
Distributions received in excess of equity income				1.6	6.3
Return of capital from Northern Border Pipeline	**23.8**	15.2	11.7	1.0	
Return of capital from Tuscarora	**1.8**	0.8	0.1		
Cash distributions from investments	**88.1**	69.2	69.3	52.4	53.8

(b) 2006 acquisitions include a 20 per cent general partner interest in Northern Border Pipeline on April 6th and a 49 per cent general partner interest in Tuscarora on December 19th.

(c) Reconciliation of non-GAAP financial measure: Cash distributions from investments net of Partnership costs is a non-GAAP financial measure which is equal to Cash distributions from investments less the Partnership s costs. We exclude Tuscarora s costs from the Partnership costs so that investors may evaluate our costs independent of costs directly attributable to our investments. Management believes that this is a useful measure to assist the Partnership s investors in evaluating the Partnership s business performance. A reconciliation of Partnership costs is summarized below:

(millions of dollars)	2006	2005	2004	2003	2002
Operations, maintenance and administrative expenses	**(2.7)**	(2.0)	(1.9)	(1.7)	(1.5)
Financial charges, net and other	**(15.8)**	(1.0)	(0.5)	(0.1)	(0.5)
Less:					

Operations, maintenance and administrative expenses and financial charges from Tuscarora additional 49% interest acquired December 19, 2006	**(0.3)**				
Partnership costs	**(18.2)**	(3.0)	(2.4)	(1.8)	(2.0)

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Total cash distributions received from our investments in Northern Border Pipeline and Tuscarora for the year ended December 31, 2006 were $88.1 million, an increase of $18.9 million, compared to $69.2 million for the same period last year. The acquisition of an additional 20 per cent general partner interest in Northern Border Pipeline contributed $26.7 million. The increase in Partnership costs in 2006 was primarily due to financing of the 2006 acquisitions.

Distributions from Northern Border Pipeline decreased in 2006 compared to 2005, resulting in a $7.2 million reduction in distributions received by the Partnership for its original 30 per cent general partner interest. Distributions made by Northern Border Pipeline were higher in 2005 mainly due to higher revenues and $9.4 million realized on the sale of its unsecured bankruptcy claims for transportation contracts and associated guarantees held against Enron Corp. and Enron North America Corp. The Partnership s then 30 per cent interest in this additional revenue was $2.8 million.

Distributions from Tuscarora decreased in 2006 compared to 2005, resulting in a $0.6 million reduction in distributions received by the Partnership for its original 49 per cent general partner interest. This decrease is primarily due to lower net revenues resulting from lower settlement rates effective June 1, 2006.

Distributions from Northern Border Pipeline of $60.9 million in 2005 decreased by $0.8 million, or one per cent, compared to 2004. Distributions from Tuscarora of $8.3 million in 2005 increased by $0.7 million, or nine per cent compared to the prior year. Partnership costs of $3.0 million in 2005 compared to $2.4 million in 2004 increased mainly due to higher financial charges as a direct result of both higher average interest rates and higher average debt balances.

Net Income

To supplement our financial statements we have also summarized the net income contribution by our investments and separately identifying the direct financing and other costs of the Partnership. We have presented net income in this format in to enhance an investor s understanding of the way management analyzes the Partnership s financial performance. We believe this summary provides a more meaningful comparison of the Partnership s net income in 2006 (which was impacted by the 2006 acquisitions) to prior years. 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.

(millions of dollars)	**2006**	**2005**	**2004**
Income from initial 30% general partner interest in Northern Border Pipeline	**38.8**	45.7	50.0
Income from initial 49% general partner interest in Tuscarora	**6.1**	7.5	7.5
Income from Northern Border Pipeline additional 20% interest acquired April 6, 2006	**17.8**		
Income from Tuscarora additional 49% interest acquired December 19, 2006	**0.2**		
Partnership costs	**(18.2)**	(3.0)	(2.4)
Net Income as reported	**44.7**	**50.2**	**55.1**

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Net income decreased $5.5 million, or 11 per cent, to $44.7 million in 2006, compared to $50.2 million in 2005. Net income for the year ended December 31, 2005 included the impact of the sale of the bankruptcy claims against Enron by Northern Border Pipeline, which increased the Partnership s 2005 income by $2.8 million. Excluding the impact of the sale of the bankruptcy claims in 2005, the Partnership s net income decreased by $2.7 million in 2006 compared to 2005. This decrease was primarily due to lower revenues and higher operations and maintenance expenses at Northern Border Pipeline, partially offset by the net impact of acquisitions made during the year.

Equity income from the Partnership s investment in Northern Border Pipeline increased $10.9 million, or 24 per cent, to $56.6 million in 2006 compared to $45.7 million in 2005. The increase in equity income from Northern Border Pipeline was largely due to the Partnership s additional 20 per cent general partner interest which contributed $17.8 million in equity income as well as increased revenues related to the Chicago III Expansion project. This increase was partially offset by a reduction in Northern Border Pipeline s net income primarily due to a one-time increase in Northern Border Pipeline s revenues included in 2005, lower revenues related to discounting and unsold capacity, and higher operations and maintenance expenses. In 2005, Northern Border Pipeline recognized a one-time revenue amount of $9.4 million due to the sale of its bankruptcy claims against Enron and Enron North America. The increased operations and maintenance expenses of Northern Border Pipeline as compared to 2005 are due to increased general and administrative expenses and electric compression charges associated with the Chicago III Expansion Project.

Equity income from the Partnership s investment in Tuscarora was $5.9 million for the year ended December 31, 2006, a decrease of $1.6 million, or 21 per cent, compared to $7.5 million in 2005. As a result of the acquisition of an additional 49 per cent general partner interest in Tuscarora on December 19, 2006, the Partnership subsequently consolidates its interest in Tuscarora. The $0.4 million of earnings for the last twelve days of 2006 together with the $5.9 million of equity earnings up to December 19 resulted in total net income from Tuscarora of $6.3 million. This amount was $1.2 million, or 16 per cent, lower than 2005 primarily due to lower net revenues resulting from settlement rates effective June 1, 2006.

The Partnership s transmission revenues and depreciation expense for 2006 were $0.9 million and $0.2 million, respectively. These amounts relate to Tuscarora s operations on a consolidated basis for the last twelve days of 2006.

The Partnership s operations, maintenance and administrative expenses of $2.7 million for 2006 increased $0.7 million compared to $2.0 million in 2005. The increase in operations, maintenance and administrative expenses is primarily related to increased salaries and benefits allocated to the Partnership by its operator and increased legal costs, as well as an additional $0.1 million related to Tuscarora operations for the last twelve days of 2006.

Financial charges, net and other were $15.8 million for 2006, an increase of $14.8 million compared to 2005. The higher financial charges were mainly due to an increased outstanding debt balance.

Year Ended December 31, 2005 Compared with the Year Ended December 31, 2004

Net income decreased $4.9 million, or 9 per cent, to $50.2 million in 2005, compared to $55.1 million in 2004. The decrease was primarily due to lower equity income from the Partnership s investment in Northern Border Pipeline.

Equity income from the Partnership s investment in Northern Border Pipeline decreased $4.3 million, or 9 per cent, to $45.7 million in 2005 compared to $50.0 million in 2004. The decrease was primarily attributable to lower revenues and higher costs and expenses from Northern Border Pipeline. Northern Border Pipeline s revenues in 2005 were $16.2 million lower compared to 2004 primarily as a result of unsold transportation capacity and discounted transportation rates, partially offset by the sale of bankruptcy claims against Enron and Enron North America. During the second quarter of 2005, contracts for 800 MMcf/d of transportation capacity on the Port of Morgan, Montana to Venture, Iowa portion of Northern Border Pipeline expired and some of this transportation capacity was not sold. To maximize revenue, Northern Border Pipeline discounted transportation rates primarily on a short-term basis and sold most of its remaining capacity in 2005. Partially offsetting this reduction in revenues, Northern Border Pipeline recognized revenue in the amount of $9.4 million related to the sale of its bankruptcy claims against Enron and Enron North America. The net negative impact to TC PipeLines equity income was approximately $2.2 million. In 2004, Northern Border Pipeline recognized revenue of $0.9 million due to an additional day of transportation service because of the leap year. Northern Border Pipeline s costs and expenses were $7.6 million higher in 2005 compared to 2004 as a result of higher operations and maintenance expense of $5.7 million and higher taxes other than income of $1.9 million. The increase in operations and maintenance expense was primarily due to settlement of several outstanding issues related to Enron which reduced Northern Border Pipeline s operations and maintenance expense in 2004. These issues include resolution of Northern Border Pipeline s potential obligation for costs related to the termination of Enron s cash balance plan, the settlement for certain administrative expenses for 2002 and 2003, and an adjustment to its allowance for doubtful accounts related to bankruptcy claims. The impact of the increase in operations and maintenance expense and taxes other than income to TC PipeLines were approximately $2.3 million. Northern Border Pipeline s taxes other than income increased $1.9 million in 2005 compared to the same period in 2004 primarily due to increased tax expense related to Minnesota compressor fuel tax and increased property taxes. Northern Border Pipeline s net interest expense increased $1.3 million in 2005 compared to 2004 due to higher average interest rates on its credit agreement which increased to 5.11 per cent from 1.95 per cent, partially offset by decreased average debt outstanding. Net other income increased $1.6 million in 2005 compared to 2004 primarily due to adjustments to Northern Border Pipeline s allowance for doubtful accounts which increased net other income in 2005. Non-recurring expenses incurred in 2004 related to business development reduced net other income. The net positive impact of these changes to TC PipeLines equity income was $0.2 million in 2005.

Equity income from the Partnership s investment in Tuscarora remained flat at $7.5 million in 2005 compared to 2004. Costs and expenses decreased $0.5 million in 2005, or 10 per cent compared to 2004 as a result of a $0.4 million decrease in operations and maintenance expense and a $0.1 million decrease in taxes other than income. The decrease in operations and maintenance expense was primarily due to the renegotiation of lower rates for maintenance contracts in 2005. The impact of these decreases in Tuscarora s cost and expenses to TC PipeLines equity income was approximately $0.2 million. Tuscarora s interest expense decreased $0.3 million, or five per cent in 2005 compared to 2004 primarily due to lower average debt outstanding. Tuscarora s other income decreased $0.6 million, or 80 per cent in 2005 compared to 2004. The decrease was primarily due to a one-time income item received in 2004 related to the termination of Tuscarora s 2005 expansion. A joint settlement agreement was filed and approved by the FERC allowing Tuscarora to withdraw its application for the proposed 2005 expansion facilities and released the 2005 expansion customers from their contractual commitments.

The Partnership recorded operations, maintenance and administrative expenses of $2.0 million and $1.9 million in 2005 and 2004, respectively.

The Partnership recorded financial charges, net and other of $1.0 million and $0.5 million in 2005 and 2004, respectively. The increase was due to both higher average interest rates and higher average debt balances.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES, LP

Overview

Our principal sources of liquidity include cash generated from operating activities and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow.

Cash Distribution Policy of TC PipeLines

The Partnership makes distributions of Available Cash, as defined in the Partnership Agreement, in the following manner:

- First, 98 per cent to the common units, pro rata, and two per cent to the general partner, until there is distributed for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and

- Thereafter, in a manner whereby the general partner has rights (referred to as incentive distribution rights) to receive increasing percentages of excess quarterly cash distributions over specified cash distribution thresholds calculated as follows:

Additional Available Cash from Operating Surplus (as defined in the partnership agreement) for that quarter will be distributed, among the unitholders and the general partner (as incentive distribution) in the following manner:

- First, 85 per cent to all units, pro rata, and 15 per cent to the general partner, until each unitholder has received a total of $0.5275 for that quarter;

- Second, 75 per cent to all units, pro rata, and 25 per cent to the general partner, until each unitholder has received a total of $0.6900 for that quarter; and

- Third, 50 per cent to all units, pro rata, and 50 per cent to the general partner.

The distribution to the general partner described above, other than in its capacity as a holder of 2,035,106 units that are in excess of its aggregate two per cent general partner interest, represent the incentive distribution rights.

General

On January 18, 2007, the Board of Directors of the general partner declared the Partnership s 2006 fourth quarter cash distribution. The fourth quarter cash distribution was payable on February 14, 2007 to unitholders of record as of January 31, 2007. The total cash distribution of $11.3 million was paid in the following manner: $10.5 million to common unitholders (including $1.2 million to the general partner as holder of 2,035,106 common units), $0.6 million to the general partner as holder of the incentive distribution rights, and $0.2 million to the general partner in respect of its two per cent general partner interest.

Summary of Contractual Obligations

The Partnership s contractual obligations related to long-term debt as of December 31, 2006, include the following:

	Payments Due by Period				
(millions of dollars)	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Senior Credit Facility (1)	397.0			397.0	
Interest payments on Senior Credit Facility	119.2	24.1	48.2	46.9	
Total	516.2	24.1	48.2	443.9	

(1) The Partnership s long-term debt (including current maturities) consists of the Senior Credit Facility and Tuscarora s Senior Notes of $71.1 million (see Liquidity and Capital Resources of Tuscarora Gas Transmission Company Summary of Contractual Obligations).

Debt and Credit Facilities

On February 28, 2006, we renewed a $20.0 million, previously $30.0 million, unsecured credit facility (Revolving Credit Facility). Loans under the Revolving Credit Facility bear interest, at the option of the Partnership, at a one-, two-, three-, or six-month (London interbank offered rate) LIBOR plus 0.75 per cent or 1.00 per cent if total debt is greater than or equal to 15 per cent of capitalization, or at a floating rate based on the higher of the federal funds effective rate plus 0.5 per cent and the prime rate. In 2005, we repaid $16.5 million on the Revolving Credit Facility and had $13.5 million outstanding at December 31, 2005. In 2006, we repaid the Revolving Credit Facility in full and it was terminated. The interest rate on the Revolving Credit Facility averaged 5.60 per cent and 4.40 per cent for the years ended December 31, 2006 and 2005, respectively, and at December 31, 2005 the interest rate was 5.62 per cent.

On March 31, 2006, we entered into an unsecured credit agreement for a $310 million credit facility (Bridge Loan Credit Facility) with a banking syndicate. Borrowings under the Bridge Loan Credit Facility bear interest, at the option of the Partnership, at the LIBOR or the base rate plus an applicable margin. On April 5, 2006, the Partnership borrowed $307 million under the Bridge Loan Credit Facility to finance the purchase price and a $10 million transaction fee payable in connection with the acquisition of an additional 20 per cent general partnership interest in Northern Border Pipeline. The remaining $3 million commitment under the Bridge Loan Credit Facility was terminated.

On December 12, 2006, the Bridge Loan Credit Facility was refinanced through a $297 million draw on a $410 million credit agreement (Senior Credit Facility) with a banking syndicate and the use of $10 million cash on hand. The interest rate on the Bridge Loan Credit Facility averaged 6.29 per cent for the year ended December 31, 2006. Proceeds from the Senior Credit Facility may be used to refinance existing debt, to finance the Tuscarora acquisition and working capital needs, and for other general corporate purposes. On December 19, 2006, we borrowed an additional $100 million under the Senior Credit Facility to finance the purchase price of an additional 49% general partner interest in Tuscarora. The Senior Credit Facility matures on December 12, 2011, at which time all amounts outstanding will be due and payable. Amounts borrowed may be repaid in part or in full prior to that time without penalty. Borrowings under the Senior Credit Facility will bear interest based, at the Partnership s

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election, on the LIBOR or the prime rate plus, in either case, an applicable margin. There was $397 million outstanding under the Senior Credit Facility at December 31, 2006. The interest rate on the Senior Credit Facility averaged 6.16 per cent for the year ended December 31, 2006 and at December 31, 2006, the interest rate was 6.07 per cent. At December 31, 2006, the Partnership was in compliance with its financial covenants.

On February 13, 2007, we entered into an unsecured amended and restated credit agreement (the Credit Agreement) for a $950 million credit facility with SunTrust Bank, as administrative agent. The Credit Agreement includes a $700 million term loan facility and a $250 million revolving loan facility. The Credit Agreement amends and restates the Senior Credit Facility. The pricing and other material terms of the Credit Agreement remain predominantly the same as the pricing and material terms of the Senior Credit Facility. As of February 13, 2007, the Partnership had borrowed $380 million in term loans under the Credit Agreement. A further $126 million was drawn under the Credit Agreement in conjunction with the acquisition of a 46.45 per cent general partnership interest in Great Lakes on February 22, 2007. The remaining $194 million commitment under the term loan facility was terminated on the same date. The Credit Agreement has a term of five years, and all amounts outstanding under the Credit Agreement will be due and payable 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. The Credit Agreement also requires the Partnership to maintain a leverage ratio of not more than 4.75 to 1.00 at the end of any fiscal quarter. The permitted leverage ratio will increate 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.

The Partnership uses derivatives to assist in managing its exposure to interest rate risk. The fair value of interest rate derivatives has been calculated using year-end market rates. At December 31, 2006, the fair value of the Partnership s interest rate swaps accounted for as hedges was $1.6 million. The notional or principal amount was $200 million. The interest rate swaps are structured such that the cash flows match those of the Senior Credit Facility, becoming effective March 12, 2007 and maturing December 12, 2011. Subsequent to year end, an additional $100 million of debt was hedged by interest rate swaps with the same term.

Equity Contributions

In January, May and December 2004, the Partnership made its share of equity contributions to Northern Border Pipeline in the amount of $19.5 million, $19.5 million and $22.5 million, respectively, to repay existing bank debt. The equity contribution of $22.5 million made in December 2004 reduces the previously approved 2007 equity cash call from $90 million to $15 million, of which the Partnership s share will be $7.5 million. The remaining $7.5 million is expected to be paid to Northern Border Pipeline in May 2007 to assist Northern Border Pipeline in repaying maturing senior notes in the amount of $150 million. In March 2006, the Partnership made a further equity contribution to Northern Border Pipeline of $3.1 million to fund Chicago III Expansion Project capital costs.

In August 2005, the Partnership made its share of an equity contribution to Tuscarora in the amount of $0.3 million for construction of the Barrick Lateral that went into service June 2005.

Cash Flows from Operating, Investing and Financing Activities

Operating Activities

Cash flows provided by operating activities decreased $4.0 million, or eight per cent, to $46.1 million for 2006, compared to $50.1 million for 2005. This decrease was primarily due to lower equity income from Northern Border Pipeline and Tuscarora related to the Partnership s original ownership interests, partially offset by the increased ownership in Northern Border Pipeline and Tuscarora which resulted in $17.8 million and $0.2 million of equity income recognized, respectively. The increased equity income from the Partnership s investment in Northern Border Pipeline and Tuscarora was partially offset by increased financing costs related to the acquisition of additional interests in these entities.

The Partnership received cash distributions of $80.4 million in 2006 and $60.9 million in 2005 from its equity investment in Northern Border Pipeline. This $19.5 million increase in cash distributions from Northern Border Pipeline consisted of an increase of $26.7 million related to the Partnership s acquisition of an additional 20 per cent general partner interest, partially offset by a decrease of $7.2 million related mainly to reduced equity income from Northern Border Pipeline. The cash distributions received include $23.8 million and $15.2 million classified as

return of capital in 2006 and 2005, respectively. The section Liquidity and Capital Resources of Northern Border Pipeline Company contains cash flow details for Northern Border Pipeline at an operating level.

Cash flows from the Partnership s investment in Tuscarora were accounted for as cash distributions from the Partnership s equity investment until December 19, 2006. On that date, the Partnership closed the acquisition of the additional 49 per cent general partner interest in Tuscarora. Subsequent to December 19, 2006, the cash flows related to the investment in Tuscarora have been consolidated in the cash flows of the Partnership. Cash distributions received in 2006 from Tuscarora prior to the incremental investment were $7.7 million compared to $8.3 million of cash distributions received for the full year of 2005. The cash distributions received include $1.8 million and $0.8 million classified as return of capital for the period from January 1 to December 19, 2006 and the full year of 2005, respectively. The section Liquidity and Capital Resources of Tuscarora Gas Transmission Company contains cash flow details for Tuscarora at an operating level.

Cash flows provided by operating activities decreased $5.1 million, or nine per cent, in 2005 compared to 2004. The decrease was primarily due to lower equity income from Northern Border Pipeline. The decrease in equity income was primarily due to lower revenues and higher operations and maintenance expense from Northern Border Pipeline in 2005. Partially offsetting this decrease was the sale of Northern Border Pipeline s bankruptcy claims against Enron and Enron North America.

Investing Activities

Cash used in investing activities increased by $397.7 million in 2006 to $382.0 million compared to cash generated of $15.7 million in 2005. This increase is attributed mainly to acquisitions completed in 2006. The Partnership paid approximately $311.1 million and $97.2 million in 2006 for the acquisitions of an additional 20 per cent general partner interest in Northern Border Pipeline and an additional 49 per cent general partner interest in Tuscarora, respectively. The Partnership also made an equity contribution of $3.1 million, representing its then 30 per cent share of a cash call issued by Northern Border Pipeline to its partners on March 29, 2006.

Cash distributions received from Northern Border Pipeline which were classified as return of capital were $23.8 million and $15.2 million for 2006 and 2005, respectively. This increase in cash distributions can be attributed mainly to the additional 20 per cent interest in Northern Border Pipeline acquired on April 6, 2006. Cash distributions received from Tuscarora which were classified as return of capital were $1.8 million and $0.8 million for the periods ended December 19, 2006 and December 31, 2005, respectively. More details about cash flows at Northern Border Pipeline and Tuscarora can be found in the Liquidity and Capital Resources of Northern Border Pipeline Company and Liquidity and Capital Resources of Tuscarora Gas Transmission Company sections, respectively.

In 2005, the Partnership made a $0.3 million equity contribution to Tuscarora for construction of the Barrick Lateral compared to equity contributions of $61.5 million in 2004. The equity contributions in 2004 represent the Partnership s then 30 per cent share of two $65 million cash calls issued by Northern Border Pipeline to its partners in January and May of 2004 and its then 30 per cent share of a $75 million cash call issued by Northern Border Pipeline to its partners in December 2004. In 2005, aggregate return of capital from Northern Border Pipeline and Tuscarora was $16.0 million compared to $12.1 million in 2004. The increase was primarily due to Northern Border Pipeline s higher third quarter earnings that were due to the recognition of revenue of $9.4 million related to the sale of bankruptcy claims against Enron and Enron North America. Tuscarora s return of capital included a one-time settlement payment that was received in the fourth quarter of 2004 related to the termination of Tuscarora s 2005 expansion.

Financing Activities

Cash flows from financing activities were $337.6 million in 2006, compared to cash used for financing activities of $66.0 million in 2005. The increase in financing was to support the acquisition activities in 2006. To finance the 2006 acquisitions, the Partnership borrowed a net $381.1 million from bridge, term and revolving credit facilities. Tuscarora repaid $2.4 million of the outstanding balance on its senior secured notes in December 2006.

For the year ended December 31, 2006, the Partnership paid $43.5 million in cash distributions, an increase of $0.5 million compared to the prior year. The increase is due an increase in the Partnership s quarterly cash distribution from $0.575 per unit to $0.60 per unit beginning in the fourth quarter of 2006.

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Cash used for financing activities in 2005 increased by $55.2 million to $66.0 million compared to 2004. The Partnership paid cash distributions of $43.0 million in 2005 compared to $41.8 million in 2004. The increase was primarily due to an increase in the Partnership s quarterly cash distribution from $0.55 per unit to $0.575 per unit beginning in the second quarter of 2004. In 2005 and 2004, the Partnership repaid $23.0 million and $6.0 million, respectively, on its Revolving Credit Facility.

Capital Requirements

To the extent we have additional capital requirements with respect to its investments in Northern Border Pipeline and Tuscarora or makes acquisitions in 2007, TC PipeLines expects to finance these requirements with operating cash flows, debt and/or equity.

Outlook

On February 22, 2007, the Partnership announced it had closed its acquisition of a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation. The total purchase price was $962 million, subject to certain closing adjustments, and included the indirect assumption of approximately $212 million of debt. The acquisition was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600 million which closed concurrently with the acquisition. TransCan Northern Ltd. purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300 million. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with this transaction. The amount available under the senior credit facility increased from $410 million to $950 million, consisting of a $700 million senior term loan and a $250 million senior revolving credit facility, with $194 million of the senior term loan available being terminated upon closing of the acquisition. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private equity placement.

RESULTS OF OPERATIONS OF NORTHERN BORDER PIPELINE COMPANY

In the following discussion of the results of Northern Border Pipeline, all amounts represent 100 per cent of the operations of Northern Border Pipeline, in which the Partnership held a 50 per cent interest at December 31, 2006. The Partnership has held its initial 30 per cent interest since May 28, 1999 and purchased an additional 20 per cent interest on April 6, 2006.

The discussion and analysis of Northern Border Pipeline s financial condition and operations are based on Northern Border Pipeline s financial statements, which were prepared in accordance with GAAP. The following discussion and analysis should be read in conjunction with Northern Border Pipeline s Financial Statements and related notes included elsewhere in this report.

Overview

Northern Border Pipeline is a Texas general partnership formed in 1978. ONEOK Partners and TC PipeLines each own a 50 percent interest in Northern Border Pipeline. Northern Border Pipeline provides natural gas transportation services and is a leading transporter of natural gas imported from Canada to the U.S.

Northern Border Pipeline s operating revenue is derived from transportation of natural gas. 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 also pay a fee known as a commodity charge that is based on the mileage and volume of natural gas they transport. Customers with interruptible service transportation agreements may utilize available capacity on Northern Border Pipeline s system 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. In 2006, 96 per cent of Northern Border Pipeline s transportation revenue was derived from reservation charges.

Information about Northern Border Pipeline s business, properties and strategy can be found under Item 1, Business Business of Northern Border Pipeline Company .

Business Environment

Supply

A healthy long-term natural gas supply outlook is critical for Northern Border Pipeline s operations. Western Canada supply trends are particularly important because approximately 85 per cent of the natural gas Northern Border Pipeline transports is produced in the Western Canada Sedimentary Basin. Northern Border Pipeline estimates that its pipeline transported approximately 20 per cent of Canada s natural gas export volume in 2006. In 2006, Canadian natural gas supplies available for export were relatively flat compared with prior years.

Canadian natural gas export volumes may decrease in 2007 as compared to 2006. Some industry analysts are predicting a decline in Canadian natural gas supply available for export by as much as 1 Bcf/d or approximately 11 per cent as drilling activity slows and natural gas demand in Canada grows. In the fourth quarter of 2006, it was reported that active drilling rigs declined by over 20 per cent as compared to the same period in 2005. For 2007, it has been reported that Canadian producers have made significant reductions to their capital programs due to rising service costs and lower gas prices. Demand for natural gas in Canada is expected to increase due to increased natural gas consumption associated with the development and production of oil sand reserves. Increased production of crude oil from oil sand reserves in Canada could reduce natural gas available for export to the U.S. if oil production and the related demand for natural gas are greater than supply growth. A reduction in the amount of available supply for export is a negative development for all U.S. pipelines that import natural gas from Canada, but the impact on Northern Border Pipeline will depend upon competitive factors and prevailing market conditions.

Additional Canadian natural gas supply sources for Northern Border Pipeline may result in the future if new pipeline projects associated with the Mackenzie Delta in Northern Canada and Alaska are constructed. In addition, increased drilling and production activity in the Powder River Basin may present opportunities for Northern Border Pipeline to pursue additional connections with this supply area.

Demand

The EIA reported that U.S. demand for natural gas in 2006 was approximately one per cent less than 2005 levels, primarily as a result of warmer-than-average temperatures in the first quarter of 2006. The EIA is forecasting U.S. gas consumption to increase approximately three per cent in 2007 from 2006 levels. Current weather forecasts for colder winter and cooler summer months in 2007 compared with 2006 indicate increased residential and commercial natural gas demand for heating offset by lower natural gas demand for electric generation needed to power air conditioners in the summer.

Northern Border Pipeline serves natural gas markets in the Midwestern U.S. through major interconnects with Northern Natural Gas (NNG), the largest at Ventura, Iowa, and with utilities in Iowa. Northern Border Pipeline provides its customers with access to the Chicago market area, which is the third largest market area hub in North America. NNG is experiencing demand growth on its system related to new power generation and new ethanol plant demand. NNG has a proposed pipeline expansion project that is expected to be in service by November 2007 and will add approximately 0.4 million Dth/d of incremental capacity, which could increase demand for transportation on Northern Border Pipeline s system.

Natural gas storage is essential to balance natural gas supply with temperature-driven seasonal demand. In 2006, new storage facilities were placed into service in Western Canada. Increased storage capacity may reduce demand for its transportation services during certain periods of the year. The level of price spreads between supply areas and market areas may be diminished with the addition of storage capacity.

Competition

Supply competition from other natural gas sources can adversely impact demand for transportation on Northern Border Pipeline s system. Recent growth in supplies available from the Rocky Mountain and Texas regions has reduced prices for natural gas delivered to some of Northern Border Pipeline s Midwestern markets relative to other market regions. The Rockies Express Pipeline, a proposed 1,663 mile pipeline system from Rio Blanco County, Colorado to Monroe County, Ohio, may also increase supply competition in Midwestern markets. The western segment of the Rockies Express Pipeline, a 713 mile pipeline from Colorado to Missouri, is anticipated to be placed in service by 2008, and initially is expected to add more supply competition in markets served by Northern Border Pipeline. The eastern segment of the Rockies Express Pipeline, a 622 mile pipeline from Missouri to Ohio, is expected to be placed in service by 2009, and is anticipated to transport natural gas further east, potentially mitigating any excess supply in Northern Border Pipeline s market region. Also, ongoing pipeline projects to move

growing East Texas production to markets in the eastern U.S. may reverse the trend of this incremental production flowing into the markets Northern Border Pipeline serves.

Seasonality

As more of Northern Border Pipeline s capacity is contracted on a short term basis, weather related demand in various regions of the country that can be served by Western Canadian supply, along with Northern Border Pipeline s market area, will have a more significant impact on Northern Border Pipeline. For example, high temperatures in the summer combined with low hydroelectric generation capability can increase demand for Canadian natural gas in the Western U.S. and shift supply away from Northern Border Pipeline s system.

Effect of Rate Case

Revenues for 2007, as compared to 2006, are expected to be lower due to the reduction of long-term rates effective January 1, 2007, pursuant to the rate case settlement discussed under Business of Northern Border Pipeline Company Government Regulation in Item 1 of this report. In addition, quarterly revenues may be more variable in 2007 due to the implementation of seasonal rates included in the rate case settlement. In 2007, Northern Border Pipeline expects to continue discounting transportation capacity to optimize revenue.

Year in Review

In 2006, the trend toward shorter term contracts and discounted transportation rates continued on Northern Border Pipeline s system. The weighted average life of Northern Border Pipeline s contracts declined from 2.2 years at December 31, 2005 to 1.8 years at December 31, 2006. As long-term contracts expired, the amount of available capacity to sell increased. This resulted in the sale of more short-term contracts and a greater amount of capacity sold at discounted rates.

In April 2006, ONEOK Partners sold a 20 per cent partnership interest in Northern Border Pipeline to TC PipeLines. Northern Border Pipeline amended and restated its General Partnership Agreement as a result of this ownership interest change. In addition, Northern Border Pipeline entered into an operating agreement with TransCan. Under the new operating agreement, TransCan will become Northern Border Pipeline s operator effective April 1, 2007. Further information about these transactions can be found under Item 1, Business of Northern Border Pipeline Company Recent Developments.

In April 2006, the Chicago III Expansion Project went into service as planned, adding 130 MMcf/d of transportation capacity from Harper, Iowa to the Chicago market area with the construction of a new 16,000-horsepower compressor station in Iowa and minor modifications to two other compressor stations in Iowa and Illinois. This expansion is fully subscribed by four shippers under long-term firm service transportation agreements with terms ranging from five and one-half to ten years and provided additional revenues of $4.0 million in 2006.

On November 21, 2006 the FERC approved the uncontested settlement of Northern Border Pipeline s rate case. The settlement was reached between Northern Border Pipeline and its participant customers and was supported by the FERC trial staff. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border Pipeline s system. Beginning in 2007, overall rates were reduced, compared with rates prior to the filing, by approximately 5 per cent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dth is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The factors used in calculating depreciation expense for transmission plant were increased from 2.25 per cent to 2.40 per cent. 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 Northern Border Pipeline files a rate case within six years.

The natural gas industry continues to be a critical component of the energy infrastructure in the U.S. Northern Border Pipeline s commitment to providing safe, cost-effective and reliable natural gas transportation service will continue to be the foundation upon which Northern Border Pipeline will strive to grow its business and provide consistent cash flow to its partners. Northern Border Pipeline s priorities in 2007 include marketing its available transportation capacity and actively pursuing potential pipeline projects to access new supply areas and markets.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires Northern Border Pipeline 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 Northern Border Pipeline believes these estimates and assumptions are reasonable, actual results could differ from its estimates and assumptions. The following summarizes Northern Border Pipeline s critical accounting estimates, which should be read in conjunction with Note 2 of Northern Border Pipeline s Financial Statements included elsewhere in this report.

Regulatory Assets

Northern Border Pipeline s accounting policies conform to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Northern Border Pipeline considers several factors to evaluate its continued application of the provisions of SFAS No. 71 such as potential deregulation of its pipeline; anticipated changes from cost-based ratemaking to another form of regulation; increasing competition that limits Northern Border Pipeline s 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 Pipeline s balance sheet as regulatory assets. If Northern Border Pipeline determines future recovery of these assets is no longer probable as a result of discontinuing application of SFAS No. 71 or other regulatory actions, Northern Border Pipeline would be required to write off the regulatory assets at that time. As of December 31, 2006, Northern Border Pipeline reflected regulatory assets of $19.1 million on the balance sheet. These assets are being amortized as directed by the FERC in Northern Border Pipeline s current or previous regulatory proceedings over varying time periods up to 44 years.

Contingencies

Northern Border Pipeline s accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. Northern Border Pipeline accrues these contingencies when its 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 SFAS No. 5, Accounting for Contingencies. Northern Border Pipeline bases its estimates on currently available facts and its estimates of the ultimate outcome or resolution. Actual results may differ from Northern Border Pipeline s estimates resulting in an impact, positive or negative, on earnings.

Results of Operations

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Net income decreased $22.4 million, or 15 per cent, in 2006 compared with 2005 primarily due to decreased operating revenues and increased operations and maintenance expense.

Operating revenue decreased $10.8 million in 2006 compared with 2005 primarily due to the following:

- a one-time increase in revenue in the third quarter of 2005 of $9.4 million due to the recognition of the sale of Northern Border Pipeline s bankruptcy claims for transportation contracts and associated guarantees held against Enron and Enron North America; and

- decreased firm demand revenue and commodity charges of $5.5 million as a result of discounted transportation rates, transportation capacity that was sold for shorter transportation paths and unsold capacity; partially offset by

- additional revenue of $4.0 million from transportation contracts related to the Chicago III Expansion Project.

Operations and maintenance expense increased $10.0 million in 2006 compared with 2005 primarily a result of increased general and administrative expenses of $6.9 million and electric compression charges associated with the Chicago III Expansion Project of $3.1 million. The increase to general and administrative expenses was primarily related to increased salaries, benefits and expenses of Northern Border Pipeline s operator and its affiliates attributable to Northern Border Pipeline s operations.

The remaining decrease in net income of $1.6 million in 2006 compared with 2005 was due to increased depreciation and amortization, taxes other than income and interest expense, and decreased net other income.

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

Net income decreased $14.5 million, or 9 per cent, in 2005 compared with 2004 primarily as a result of unsold transportation capacity, discounted transportation rates, increased operations and maintenance expense and taxes other than income, partially offset by the sale of bankruptcy claims against Enron and Enron North America.

Operating revenue decreased $7.5 million in 2005 compared with 2004. During the second quarter of 2005, contracts for 800 MMcf/d of transportation capacity on the Port of Morgan, Montana to Ventura, Iowa portion of Northern Border Pipeline s system expired. Some of this firm transportation capacity was not sold in 2005. To maximize revenue, Northern Border Pipeline discounted transportation rates primarily on a short-term basis and sold most of its remaining capacity in 2005. Revenue from firm service transportation decreased $16.2 million as a result of uncontracted and discounted capacity. Partially offsetting this decrease, Northern Border Pipeline recognized revenue of $9.4 million from the sale of its bankruptcy claims for transportation contracts and associated guarantees against Enron and Enron North America. In 2004, Northern Border Pipeline recognized revenue of $0.9 million due to an additional day of transportation service because of the leap year.

Operations and maintenance expense increased $5.7 million in 2005 compared with 2004 primarily due to the settlement or anticipated settlement of several outstanding issues related to Enron which reduced expenses in 2004. The resolution of Northern Border Pipeline s potential obligation for costs related to the termination of Enron s cash balance plan, the settlement for certain administrative expenses for 2002 and 2003, and an adjustment to allowance for doubtful accounts related to bankruptcy claims reduced expenses by $5.9 million in 2004.

Taxes other than income increased $2.0 million in 2005 compared with 2004 due to increased tax expense related to Minnesota compressor fuel tax and increased property taxes. In July 2005, the Minnesota legislature passed an omnibus tax bill, which included a provision restoring a sales tax on pipeline fuel and equipment purchases that had been struck down by the Minnesota Supreme Court in 2002. The provision became effective for purchases made after July 31, 2005. As a result, Northern Border Pipeline is taxed on the value of the gas provided in-kind and used in the operation of its compressor stations.

Interest expense increased $1.3 million in 2005 compared with 2004 as a result of higher average interest rates partially offset by decreased average debt outstanding.

Net other income increased $1.6 million in 2005 compared with 2004 primarily due to adjustments to allowance for doubtful accounts which increased net other income in 2005. Non-recurring expenses incurred in 2004 related to business development reduced net other income.

LIQUIDITY AND CAPITAL RESOURCES OF NORTHERN BORDER PIPELINE COMPANY

Overview

Northern Border Pipeline s principal sources of liquidity include cash generated from operating activities and bank credit facilities. Northern Border Pipeline funds its 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 Northern Border Pipelines partners. Northern Border Pipeline s ability to access capital markets for debt under reasonable terms depends on its financial condition, credit ratings and market conditions.

Northern Border Pipeline believes that its ability to obtain financing at reasonable rates and its history of consistent cash flow from operating activities provide a solid foundation to meet its future liquidity and capital resource requirements.

Short-Term Liquidity

Northern Border Pipeline uses cash from operating activities, bank credit facilities and equity contributions from its partners as its primary sources of short-term liquidity.

Credit Facility

In May 2005, Northern Border Pipeline entered into a $175 million five-year revolving credit agreement with certain financial institutions. Under this agreement, Northern Border Pipeline borrowed $29 million to pay the outstanding balance on its existing $175 million revolving credit agreement and terminated that agreement. Northern Border Pipeline may select the lender s base rate or the LIBOR plus a spread that is based on its long-term unsecured debt rating as the interest rate on the loan. Northern Border Pipeline is required to comply with certain financial, operational and legal covenants, including the maintenance of Northern Border Pipeline s EBITDA (net income plus interest expense, income taxes and depreciation and amortization) to interest expense ratio of greater than 3 to 1 and a debt to its adjusted EBITDA (EBITDA adjusted for pro forma operating results of acquisitions made during the year) ratio of no more than 4.5 to 1. If Northern Border Pipeline consummates one or more acquisitions that exceed $25 million in total purchase price, the allowable ratio of debt to adjusted EBITDA is increased to 5 to 1 for two calendar quarters following the acquisition. If Northern Border Pipeline breaches any of these covenants, the amount outstanding may become due and payable immediately.

The fair value of Northern Border Pipeline s variable rate debt is approximately the carrying value since the interest rates are periodically adjusted to reflect current market conditions. As of December 31, 2006, Northern Border Pipeline s outstanding borrowings under its credit agreement were $20 million and it was in compliance with the covenants of its agreement. The average interest rate on Northern Border Pipeline s credit agreement at December 31, 2006, was 6.33 per cent.

Equity Contributions

Northern Border Pipeline received equity contributions from its partners of $10.3 million during the first quarter of 2006 to fund approximately 50 per cent of the Chicago III Expansion Project capital costs. In January, May and December 2004, Northern Border Pipeline received equity contributions from its partners in the amounts of $65 million, $65 million and $75 million, respectively, to repay existing bank debt. The $75 million equity contribution in December 2004 reduces the previously approved 2007 equity cash call from $90 million to $15 million.

Long-Term Financing

Debt Securities

Northern Border Pipeline periodically issues long-term debt securities to meet its capital resource requirements. All of Northern Border Pipeline s outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Northern Border Pipeline s senior notes issuances of $150 million due in 2007, $200 million due in 2009 and $250 million due in 2021 are borrowed at fixed interest rates of 6.25 per cent, 7.75 per cent and 7.50 per cent, respectively. Northern Border Pipeline intends to maintain the current schedule of maturities, which will result in no gains or losses on its respective repayments. The indentures of the notes do not limit the amount of unsecured debt Northern Border Pipeline may incur but contain material financial covenants, including the restriction of secured indebtedness. In 2004, Northern Border Pipeline redeemed $75 million of the $225 million principal amount outstanding of its senior notes due in 2007. Northern Border Pipeline anticipates expanding its capacity under its credit agreement and utilizing borrowings under this agreement as well as equity contributions from its partners to repay its senior notes due May 1, 2007. At December 31, 2006, the aggregate fair value of Northern Border Pipeline s senior notes was approximately $623 million. In 2006, interest expense related to Northern Border Pipeline s senior notes was $43.6 million.

Cash Flow From Operating, Investing and Financing Activities

Operating Activities

Cash provided by operating activities was $185.3 million in 2006 compared with $206.5 million in 2005. The net decrease to cash provided by operating activities was primarily due to the following:

- cash received in 2005 of $11.1 million related to Northern Border Pipeline s Enron and Enron North America bankruptcy claims;
- increased cash paid to Northern Border Pipeline s operator of $7.5 million for administrative, operating and management services;
- increased expenditures to support Northern Border Pipeline s 2005 rate case of $0.7 million;
- increased cash paid for interest of $1.1 million; and
- decreased cash received from customers of $1.9 million as a result of decreased operating revenues.

Cash provided by operating activities was $206.5 million in 2005 compared with $206.1 million in 2004. In 2005, net cash inflows increased as a result of the following:

- cash received of $11.1 million related to Northern Border Pipeline s Enron and Enron North America bankruptcy claims in 2005;
- decreased cash received from customers of $16.0 million in 2005 as a result of decreased operating revenues;
- increased cash paid for interest of $3.0 million; and
- decreased payment in 2005 compared with 2004 related to Northern Border Pipeline s settlement with respect to right-of-way lease and taxation issues with the Fort Peck Tribes. Northern Border Pipeline paid the Fort Peck Tribes $7.4 million as part of the settlement in 2004 and an option payment of approximately $1.5 million in 2005.

Investing Activities

Northern Border Pipeline funds its investing activities primarily with operating cash, borrowings under its credit facilities and equity contributions from its partners. In 2006, 2005 and 2004, capital expenditures for maintenance of existing facilities and growth projects were as follows:

Capital Expenditures (millions of dollars)	**2006**	**2005**	**2004**
Maintenance	10.4	18.3	12.6
Growth	10.5	10.3	(2.0)
Total	20.9	28.6	10.6

Maintenance capital expenditures decreased $7.9 million in 2006 compared with 2005 due to a decrease in expenditures related to compressor station overhauls. Growth capital expenditures in 2006 and 2005 were primarily to spending for the Chicago III Expansion Project.

Maintenance expenditures increased $5.8 million in 2005 compared with 2004 primarily due to pipeline replacements and compressor station overhauls. Growth expenditures increased $12.3 million in 2005 compared with 2004 primarily due to spending related to the Chicago III Expansion Project.

In 2004, cash reimbursements related to pipeline interconnections more than offset growth capital expenditures, resulting in a net cash inflow of $2.0 million. Maintenance expenditures were primarily related to compressor overhauls.

Financing Activities

Cash used in financing activities was $175.5 million in 2006 compared with $176.2 million in 2005. Northern Border Pipeline received equity contributions of $10.3 million in 2006 to fund approximately 50 per cent of its expenditures for the Chicago III Expansion Project. Distributions to partners, which are calculated using operating results from the preceding quarter, decreased $24.1 million, primarily due to lower net income. In 2006, Northern Border Pipeline s net payments of debt were $7.0 million compared with net borrowings of $27.0 million in 2005.

Cash used in financing activities was $176.2 million in 2005 compared with $204.0 million in 2004. In 2005, borrowings under Northern Border Pipeline s revolving credit agreement were used primarily to repay the amount

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borrowed under its previously existing credit agreement. Total borrowings were $136.0 million and total repayments were $109.0 million. Northern Border Pipeline paid cash distributions of $202.9 million to its partners in 2005, a $2.7 million decrease from distributions paid in 2004.

In 2004, Northern Border Pipeline borrowed $107.0 million under its credit agreement and received equity contributions of $205 million from its partners. Northern Border Pipeline also terminated interest rate swap agreements with a total notional amount of $225 million and received $7.6 million. Northern Border Pipeline used the borrowings and equity contributions to repay $313.0 million of debt, which included the $75.0 million redemption of Northern Border Pipeline s senior notes due in 2007 and the related $4.8 million premium.

Capital Expenditures

In 2007, Northern Border Pipeline expects to invest approximately $13 million for maintenance capital expenditures. Northern Border Pipeline s capital expenditure estimate includes renewals and replacements of existing facilities. No significant growth capital expenditures are planned for 2007.

Commitments

Contractual Obligations

Northern Border Pipeline s contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2006, include the following:

		Pay ments Due by Period			
(millions of dollars)	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
6.25% senior notes due 2007	150.0	150.0			
7.75% senior notes due 2009	200.0		200.0		
7.50% senior notes due 2021	250.0				250.0
Credit Agreement	20.0	20.0			
Interest payments on long-term debt	320.6	37.5	63.6	37.5	182.0
Operating Leases	74.6	2.5	5.0	4.1	63.0
Other long-term obligations	5.2	1.0	2.1	2.1	
Total	1,020.4	211.0	270.7	43.7	495.0

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

Other Northern Border Pipeline is required to make future payments of approximately $1 million per year for five years under a transition services agreement between ONEOK Partners GP and TransCan for previously agreed to obligations related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used to support Northern Border Pipeline s operations. Information about the transition services agreement and transition related costs can be found under Item 13, Certain Relationships and Related Transactions, and Director Independence.

Cash Distributions

Distributions to partners are made on a pro rata basis according to each partner s capital account balance approximately one month following the end of the quarter. Northern Border Pipeline s Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, Northern Border Pipeline s cash distribution policy requires the unanimous approval of Northern Border Pipeline s Management Committee.

Northern Border Pipeline s Management Committee changed its cash distribution policy effective in January 2004 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. Upon closing the sale of the 20 per cent

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partnership interest, Northern Border Pipeline s Management Committee adopted certain changes to its cash distribution policy related to financial ratio targets and capital contributions. The change was to define minimum equity to total capitalization ratios to be used by Northern Border Pipeline s Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions.

On February 1, 2007, a cash distribution of approximately $44.4 million was declared and paid for the fourth quarter of 2006.

Contingencies

Legal

On November 1, 2005, as required by the provisions of the settlement of Northern Border Pipeline s 1999 rate case, it filed a rate case with the FERC. On November 21, 2006 the FERC approved the uncontested settlement of Northern Border s rate case. Information about the rate case is included under Item 3, Legal Proceedings.

Environmental

Northern Border Pipeline is not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

RESULTS OF OPERATIONS OF TUSCARORA GAS TRANSMISSION COMPANY

In the following discussion of the results of Tuscarora, all amounts represent 100 per cent of the operations of Tuscarora, in which the Partnership held a 98 per cent interest at December 31, 2006. The Partnership has held its initial 49 per cent interest since September 1, 2000, and acquired an additional 49 per cent interest on December 19, 2006.

The discussion and analysis of Tuscarora s financial condition and operations are based on Tuscarora s financial statements, which were prepared in accordance with GAAP. The following discussion and analysis should be read in conjunction with Note 4 Investment in Tuscarora, Notes to the Financial Statements.

Overview

Tuscarora is a Nevada general partnership formed in 1993. Its general partners are TC Tuscarora ILP, a direct subsidiary of TC PipeLines, which holds a 98 per cent general partner interest, Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, which holds a one per cent general partner interest and TCPL Tuscarora Ltd., an indirect wholly-owned subsidiary of TransCanada, which holds the remaining one per cent general partner interest in Tuscarora.

Tuscarora owns a 240-mile, 20-inch diameter, U.S. interstate pipeline system that originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation, a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs southeast through northeastern California and northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power, a subsidiary of Sierra Pacific Resources. Along its route, deliveries are made in Oregon, northern California and northwestern Nevada.

The Tuscarora pipeline system was constructed in 1995 and was placed into service in December 1995. In January 2001, Tuscarora completed construction of the Hungry Valley lateral, a 14-mile, 16-inch pipeline extension that serves as Tuscarora s second connection into Reno, Nevada. On December 1, 2002, Tuscarora completed and placed into service another expansion of its pipeline system. The 2002 Tuscarora expansion consisted of two compressor stations and an 11-mile pipeline extension from a point near the previous terminus of the Tuscarora pipeline system near Reno, Nevada to Wadsworth, Nevada. The expansion increased Tuscarora s contracted capacity from 127 MMcf/d to approximately 180 MMcf/d. The new capacity is contracted under long-term firm transportation contracts ranging from ten to fifteen years from the in-service date. Tuscarora completed construction of the Barrick Lateral, a 0.5 mile lateral that provides transportation service to a new electric generation customer located near Tracy, Nevada. The construction of the lateral was completed and commissioned for service to Barrick Goldstrike on August 1, 2005.

Year in Review

Cost and Revenue Study In accordance with a letter agreement executed on September 25, 2001 with the Public Utilities Commission of Nevada (PUCN), Tuscarora had an obligation to file a cost and revenue study with the FERC, within a reasonable timeframe following the third anniversary of the in-service date of its 2002 expansion project. The project was placed into service on December 1, 2002. As a result of that requirement, Tuscarora and the PUCN entered into settlement discussions with respect to a potential rate adjustment. On April 26, 2006, the PUCN approved a settlement with Tuscarora. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006. This is a 17 per cent reduction to the previous rate of $0.4811/dth-day, or an approximate $5 million reduction in Tuscarora s annual revenues. In addition, the settlement results in a moratorium on all rate actions before the FERC by any party to the settlement for a period of 48 months to May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate. There is no requirement to file a cost and revenue study or rate case at the end of the moratorium period. The settlement also terminates the September 2001 requirement for Tuscarora to file a cost and revenue study. All firm shippers signed on with the agreement settlement. The settlement was approved by the FERC on July 3, 2006. A compliance filing was made July 7, 2006 for the new tariffs, which were effective as of June 1, 2006. Approval for this filing was received on August 7, 2006.

Change in Ownership - On December 19, 2006, TC PipeLines acquired an additional 49 per cent general partnership interest in Tuscarora for approximately $100 million from Sierra Pacific Resources. The Partnership also indirectly assumed approximately $37 million of Tuscarora debt. TC PipeLines now owns or controls 99 per cent of Tuscarora. As a result, the Partnership now accounts for its interest in Tuscarora using the consolidation method. In connection with this transaction, TransCan became the operator of Tuscarora, which was previously operated by an affiliate of Sierra Pacific Resources. The transaction was funded with bank debt.

2008 Expansion Project - Tuscarora filed an application with the FERC on November 20, 2006 for approval to construct the compressor station and related facilities related to its Tuscarora 2008 Expansion Project . This project is to transport a maximum of 40,000 Dth/day to Sierra Pacific Power to supply its Tracy Combined Cycle Power Plant. The project is expected to cost approximately $20.7 million which will be recovered from rates charged to Sierra Pacific Power under the Transportation Service Agreement (TSA) signed with Sierra Pacific Power. The TSA is for a period of 22.5 years from the requested in-service date of February 1, 2008.

Tuscarora has requested a final Certificate of Public Convenience and Necessity from the Commission on or before July 31, 2007 in order to be able to complete the project for the 2008 summer cooling season.

Critical Accounting Estimates

Tuscarora s accounting policies conform to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Accordingly, certain assets that result from the regulated ratemaking process are recorded that would not be recorded by entities not accounting under SFAS No. 71. Tuscarora regularly evaluates the continued applicability of SFAS No. 71, considering such factors as regulatory changes, the impact of competition and the ability to recover regulatory assets.

Results of Operations

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Net income decreased $2.8 million, or 17 per cent, to $13.3 million in 2006, compared to $16.1 million in 2005. The decrease was primarily due to lower revenues.

Revenues earned by Tuscarora decreased $2.8 million, or 9 per cent, to $29.5 million in 2006, compared to $32.3 million in 2005. The decrease was mainly due to the lower rates charged after June 1, 2006 as a result of the rate settlement.

Operating expenses increased $0.3 million to $10.9 million in 2006 compared to $10.6 million in 2005. Maintenance expenses represented the majority of this increase due to additional activities undertaken in 2006.

Financial charges decreased $0.3 million, or 6 per cent, to $5.5 million in 2006, compared to $5.8 million in 2005. The decrease is due to lower outstanding debt.

Other income of $0.2 million for 2006 remained consistent with 2005.

Year Ended December 31, 2005 Compared to the Year Ended December 31, 2004

Tuscarora s net income decreased $0.2 million, or 1 per cent, to $16.1 million in 2005 compared to $16.3 million in 2004. The decrease was primarily due to lower other income and lower revenues, partially offset by lower costs and expenses and lower financial charges.

Revenues generated by Tuscarora decreased $0.3 million to $32.3 million in 2005, compared to $32.6 million in 2004. The decrease was primarily due to slightly lower transportation revenues experienced in the third quarter of 2005.

Costs and expenses incurred by Tuscarora decreased $0.5 million, or 10 per cent, to $4.4 million in 2005, compared to $4.9 million in 2004, primarily due to the renegotiation of lower rates for maintenance contracts in 2005.

Depreciation expense recorded by Tuscarora increased $0.1 million, or 2 per cent, to $6.2 million in 2005, compared to $6.1 million in 2004. The increase is primarily due to higher gross plant balance in 2005.

Financial charges recorded by Tuscarora decreased $0.3 million, or 5 per cent, to $5.8 million in 2005, compared to $6.1 million in 2004. This decrease was primarily due to lower average debt balance in 2005.

Tuscarora s other income decreased $0.6 million to $0.2 million in 2005, compared to $0.8 million in 2004. The decrease was primarily due to the recognition of a one-time settlement payment received in 2004 related to the termination of the 2005 expansion. A joint settlement agreement was filed and approved by the FERC allowing Tuscarora to withdraw its application for the proposed 2005 expansion facilities and releasing the 2005 expansion customers from their contractual commitments.

LIQUIDITY AND CAPITAL RESOURCES OF TUSCARORA GAS TRANSMISSION COMPANY

Cash Distribution Policy of Tuscarora

In September 2000, Tuscarora adopted a cash distribution policy that became effective January 1, 2001. Under the terms of the cash distribution policy and at the discretion of the Tuscarora Management Committee, Tuscarora makes quarterly cash distributions to its general partners in accordance with their respective general partner interests. Cash distributions will generally be computed as the sum of Tuscarora s net income before taxes and depreciation and amortization, less amounts required for debt repayments, net of refinancing, maintenance capital expenditures, certain non-cash items, and any cash reserves deemed necessary by the Tuscarora Management Committee. Cash distributions will be computed at the end of each calendar quarter and the distribution will be made on or before the last day of the month following the quarter end.

Summary of Contractual Obligations

Tuscarora s contractual obligations related to long-term debt, operating leases and other long-term obligations as of December 31, 2006, include the following:

	Payments Due by Period				
(millions of dollars)	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Series A Senior Notes due 2010	58.0	3.5	6.3	48.2	
Series B Senior Notes due 2010	5.9	0.5	1.0	4.4	
Series C Senior Notes due 2012	7.2	0.8	1.7	1.6	3.1
Operating Leases	0.2	0.1	0.1		
Interest payments on Senior Notes	18.3	5.0	9.0	4.2	0.1
Commitments (*)	0.7	0.7			
Total	90.3	10.6	18.1	58.4	3.2

(*) Tuscarora s commitments relate to a contract with a third party for maintenance services on certain components of its pipeline-related equipment. The contract expires in November 2007.

Debt and Credit Facilities

On March 15, 2002, Tuscarora issued Series C Senior Secured Notes in the amount of $10.0 million. These notes bear interest at 6.89 per cent and are due in 2012. The proceeds from these notes were used to finance the construction of Tuscarora s expansion facilities. On December 31, 2006, $7.2 million of the Series C Senior Notes were outstanding.

On December 21, 1995, Tuscarora issued $91.7 million of Series A Senior Secured Notes which bear interest at 7.13 per cent and mature in 2010. On December 21, 2000, Tuscarora issued $8.0 million of Series B Senior Secured Notes which bear interest at 7.99 per cent and mature in 2010. On December 31, 2006, $58.0 million and $5.9 million were outstanding on the Series A and Series B Senior Secured Notes, respectively.

Short-term liquidity needs will be met by operating cash flows. Long-term capital needs may be met through the issuance of long-term indebtedness.

Cash Flow From Operating, Investing and Financing Activities

Operating Activities

Tuscarora s cash provided by operating activities decreased $1.7 million in 2006 compared to 2005 primarily due to lower net income resulting mainly from lower revenues.

Cash flows provided by operating activities decreased $2.6 million, or 11 per cent, in 2005 compared to 2004. The decrease is primarily due a one-time settlement payment received in 2004 related to the termination of the 2005 expansion.

Investing Activities

Capital expenditures for 2006, 2005 and 2004 were as follows:

Capital Expenditures (millions of dollars)	2006	2005	2004
Maintenance	0.3	0.2	0.2
Growth	1.3	0.7	2.2
Total	1.6	0.9	2.4

Cash used for investing activities increased in 2006 compared to 2005 mainly as a result of growth capital expenditures incurred late in 2006 related to the start of construction for the 2008 expansion project.

Cash used for investing activities decreased in 2005 compared to 2004 due to lower growth and maintenance expenditures in 2005. Growth expenditures incurred in 2005 and 2004 relate to the construction of the Barrick Lateral and the 2005 expansion project that was subsequently terminated.

Capital expenditures for 2006, 2005 and 2004 were as follows:

Financing Activities

Cash flows used for financing activities decreased by $0.6 million, or 3 per cent, in 2006 compared to 2005 due mainly to lower cash distributions paid to Tuscarora s partners in 2006, partially offset by lower contributions received from Tuscarora s partners in 2006.

Cash flows used for financing activities increased $0.3 million, or 2 per cent, in 2005 compared to 2004, primarily due to higher debt repayments in 2005. Tuscarora made debt repayments of $4.9 million and $4.6 million in 2005 and 2004, respectively. In addition, Tuscarora received contributions from its partners of $0.7 million and $0.8 million in 2005 and 2004, respectively. These contributions were used to fund the construction of the Barrick Lateral and Tuscarora s 2005 expansion facilities which were subsequently terminated.

Tuscarora does not currently maintain a revolving credit facility.

Sierra Pacific Resources

Sierra Pacific Power, a wholly-owned subsidiary of Sierra Pacific Resources, is Tuscarora s largest shipper with approximately 69 per cent of the total available capacity through 2017.

On February 1, 2006, Nevada Power Company and Sierra Pacific Power (together, the Utilities) completed the settlement of long-term, ongoing litigation involving more than $300 million in terminated contracts between Enron Power Marketing Inc. (Enron) and the Utilities in accordance with the terms of the Settlement Agreement, entered into as of November 15, 2005 among the Utilities and Enron (the Settlement Agreement). As part of the settlement, the Utilities were granted an allowed, general unsecured claim (Unsecured Claim) from Enron in the aggregate amount of $126.5 million. The Utilities expect to realize no less than 30 per cent of the face value of the Unsecured Claim. In addition, the Utilities paid Enron an aggregate amount of $129 million to settle Enron s claim of more than $300 million for payments on contracts Enron terminated in 2002. The Utilities funded the termination payment amounts through available cash resources. Approximately $63.6 million held in escrow pursuant to the terms of a stipulation between Enron and the Utilities has been returned to the Utilities. This would result in the Utilities net payment to be no more than $30 million.

The Utilities intend to seek recovery of the amounts paid in connection with the Settlement Agreement, net of any proceeds received from the Unsecured Claim or from the sale of the Unsecured Claim, in future rate case filings with the Public Utilities Commission of Nevada.

Sierra Pacific Power remains current on its transportation service contracts with Tuscarora.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

TC PipeLines is exposed to market risk through changes in interest rates. The Partnership does not have any material foreign exchange risks. TC PipeLines interest rate exposure results from its Senior Credit Facility, which is subject to variability in LIBOR interest rates. At December 31, 2006, TC PipeLines had $397 million outstanding on its Senior Credit Facility. If LIBOR interest rates change by one percent compared to the rates in effect as of December 31, 2006, annual interest expense would change by less than $2.0 million. This amount has been determined by considering the impact of the hypothetical interest rates on variable rate borrowings outstanding as of December 31, 2006.

The Partnership uses derivatives to assist in managing its exposure to interest rate risk. The fair value of interest rate derivatives has been calculated using year-end market rates. At December 31, 2006, the fair value of the Partnership s interest rate swaps accounted for as hedges was $1.6 million. The notional amount hedged was $200 million. The interest rate swaps are structured such that the cash flows match those of the Senior Credit Facility between March 12, 2007 and December 12, 2011. Subsequent to year end, the Partnership borrowed a further $126 million from its Senior Credit Facility and an additional $100 million of debt was hedged by interest rate swaps, becoming effective March 12, 2007 and maturing December 12, 2011.

The Partnership is also influenced by the same factors that influence Northern Border Pipeline and Tuscarora. Neither Northern Border Pipeline nor Tuscarora owns any of the natural gas it transports, therefore, neither assumes any of the related natural gas commodity price risk.

Northern Border Pipeline utilizes both fixed- and variable-rate debt and is exposed to market risk due to the floating interest rates on its credit facility. Northern Border Pipeline regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk.

Northern Border Pipeline maintains a significant portion of its debt at fixed rates to reduce its sensitivity to interest rate fluctuations and utilizes interest rate swap agreements to convert fixed-rate debt to variable-rate debt to manage interest expense. In November 2004, Northern Border Pipeline terminated its outstanding interest rate swap agreements with notional amounts of $225 million that were entered into in May 2002. As of December 31, 2006, 97 per cent of Northern Border Pipeline s outstanding debt was at fixed rates, and there were no interest rate swap agreements outstanding. In 2007, Northern Border Pipeline expects its variable-rate debt will increase as Northern Border Pipeline plans to expand its capacity under its credit agreement and utilize borrowings under this agreement to partially fund the repayment of fixed-rate debt of $150 million due May 1, 2007.

If interest rates hypothetically increased one per cent compared with rates in effect as of December 31, 2006, Northern Border Pipeline s annual interest expense would increase and its net income would decrease by approximately $0.2 million.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the Index to Financial Statements 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 President and Chief Executive Officer and Chief 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 SEC s rules and forms.

Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2006, there has been no change in our 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.

On December 19, 2006, we acquired an additional 49 per cent interest in Tuscarora, increasing our investment in Tuscarora to 98 per cent. As it was not possible to conduct an assessment of Tuscarora s internal control over financial reporting in the period between the acquisition date and the date of management s assessment, this entity was excluded from our assessment. Despite this limitation, we have assessed our internal control over financial reporting with respect to the inclusion of our share of Tuscarora s financial position and its results for the year in our consolidated financial statements. Our 98 per cent general partner interest in Tuscarora represents 17 per cent of our consolidated total assets and 14 per cent of our consolidated net income as at and for the year ended December 31, 2006.

Based on our assessment according to the above criteria, and other than the effects, if any, that management would have considered if an assessment of internal control over financial reporting at Tuscarora would have occurred, our management concluded that our internal control over financial reporting was effective as of December 31, 2006 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 management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by our independent auditors, KPMG LLP, a registered public accounting firm, as stated in their audit report on our assessment, which is included herein on page F-3.

Item 9B. Other Information

None.

Part III

Item 10. Directors and Executive Officers and Corporate Governance

TC PipeLines 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 TC PipeLines. 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 an indirect wholly-owned subsidiary of TransCanada.

Name	Age	Position with General Partner
Russell K. Girling	44	Chairman, Chief Executive Officer and Director
Mark A.P. Zimmerman	42	President
Jack F. Jenkins-Stark	56	Independent Director
David L. Marshall	67	Independent Director
Walentin (Val) Mirosh	61	Independent Director
Gregory A. Lohnes	50	Director
Kristine L. Delkus	49	Director
Steven D. Becker	56	Director
Ronald L. Cook	49	Vice-President, Taxation
Sean M. Brett	41	Vice-President and Treasurer
Max Feldman	58	Vice-President
Donald DeGrandis	58	Secretary
Amy W. Leong	39	Controller

Mr. Girling was appointed a director of the general partner in April 1999 and Chief Executive Officer of the general partner in June 2006. Mr. Girling s principal occupation is 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. Prior to March 2003, Mr. Girling was Executive Vice-President and Chief Financial Officer of TransCanada.

Mr. Zimmerman was appointed President of the general partner on January 19, 2007. Mr. Zimmerman s principal occupation is Vice-President, Commercial Transactions of TransCanada, a position he has held since June 2006. From September 2003 to June 2006, he was Director, Project Finance for TransCanada, and from September 1999 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 principal occupation is Chief Financial Officer of SVB Financial Group (offering financial products and services, including commercial, investment, merchant and private banking and private equity services), a position he has held since April 2004. Prior to that he was Vice-President, Business Operations and Technology at Itron Inc. (a manufacturer of automated meter reading technology and a developer of energy management software), a position he held from January 2004 to March 2004. In March 2003, Mr. Jenkins-Stark was named a Managing Director at Itron following the purchase of Silicon Energy Corp. (internet-based energy and data management software) by Itron. Prior to the acquisition, Mr. Jenkins-Stark was Chief Financial Officer of Silicon Energy.

Mr. Marshall was appointed a director of the general partner in July 1999. Mr. Marshall is a retired CFO and CEO and is now a corporate director.

Mr. Mirosh was appointed a director of the general partner in September 2004. Mr. Mirosh s principal occupation is Vice-President of NOVA Chemicals Corporation and President of Olefins and Feedstocks, division of NOVA Chemicals Corporation (commodity chemical company), a position he has held since July 2003. Mr. Mirosh was Partner, MacLeod, Dixon (law firm) from January 2002 to July 2003. Mr. Mirosh is also a director of Taylor NGL Limited Partnership and Mircan Resources Inc.

Mr. Lohnes was appointed a director of the general partner on January 19, 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, Pipelines Division 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 on January 19, 2007. Mr. Becker s principal occupation is Vice-President, Pipeline Development, Pipelines Division of TransCanada, a position he has held since June 2006. From April 2003 to June 2006, he was Vice-President, Gas Development of TransCanada. Prior to April 2003, Mr. Becker was Vice-President, Market Development and Vice-President, Gas Strategy of TransCanada.

Mr. Cook was appointed Vice-President, Taxation of the general partner in April 2002. Mr. Cook s principal occupation is Vice-President, Taxation of TransCanada, a position he has held since April 2002. Prior to April 2002, Mr. Cook served as Director, Taxation of TransCanada.

Mr. Brett was appointed Vice-President and Treasurer of the general partner on January 19, 2007. Mr. Brett s principal occupation is Assistant Treasurer and Director, Capital Markets for TransCanada, a position he has held since January 2007. From 1999 to January 2007, he was Director, Capital Markets for TransCanada.

Mr. Feldman was appointed Vice-President of the general partner in September 2003. Mr. Feldman s principal occupation is Senior Vice-President, Canadian Pipelines of TransCanada, a position he has held since June 2006.

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From April 2003 to June 2006, he was Vice-President, Gas Transmission West of TransCanada. Prior to April 2003, Mr. Feldman was Senior Vice-President, Customer, Sales and Service of TransCanada.

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, Corporate Secretarial of TransCanada (pipelines and power). Prior to June 2004, Mr. DeGrandis was Director of Corporate Legal Services and Senior Legal Counsel of TransCanada.

Ms. Leong was appointed principal financial officer of the general partner on January 19, 2007 and Controller of the general partner in September 2003. Ms. Leong s principal occupation is Director, Pipeline Accounting of TransCanada, a position she has held since January 2005. From April 2003 until January 2005, Ms. Leong was Manager, Gas Transmission Accounting of TransCanada. Prior to April 2003, Ms. Leong was Manager, Regulatory Accounting and Capital Accounting of TransCanada.

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 Global 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 TC PipeLines.

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. At the time of Mr. Mirosh s appointment to the board of directors and to the audit committee on September 21, 2004, Mr. Mirosh was not independent as required under the rules of the NASDAQ Global Market but was independent as required by the rules of the SEC. The board of directors determined at the time of Mr. Mirosh s appointment that his membership on the board and the audit committee was required and in the best interest of the Partnership due to Mr. Mirosh s experience and knowledge of the industry taking into consideration the experience and mix of skills and knowledge of other members of the audit committee. As of January 1, 2006, all members of the audit committee, including Mr. Mirosh, meet the criteria for independence as set forth under the rules of the SEC and those of the NASDAQ Global 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

TC PipeLines 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 TC PipeLines 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 TC PipeLines 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 TC PipeLines

website at www.tcpipelineslp.com.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the Partnership s directors and executive officers, and persons who own more than ten per cent of the common units, to file initial reports of ownership and reports of changes in ownership (Forms 3, 4, and 5) of the common units with the SEC and the NASDAQ Global Market. Executive officers, directors and greater than ten per cent unitholders are required by SEC regulation to furnish the Partnership with copies of all such forms that they file.

Based solely upon a review of reports on Forms 3 and 4 and amendments thereto furnished to the Partnership during its most recent fiscal year and reports on Form 5 and amendments thereto furnished to the Partnership with respect to its most recent fiscal year, and written representations from officers and directors of the general partner that no Form 5 was required, the Partnership believes that all filing requirements applicable to its officers, directors and beneficial owners under Section 16(a) were complied with during the year ended December 31, 2006.

Item 11. Executive Compensation

Compensation Discussion and Analysis

As the Partnership does not have any employees, the Audit Committee of the Board of Directors and subsequently the Board of Directors of the general partner of TC PipeLines, have not been called upon to make any determination with respect to the amount of compensation to be paid to the Partnership s President and CEO. The board does, however, approve the allocation of the salary of the President and CEO to the Partnership on an annual basis. The executive officers salaries are determined on a competitive and market basis by TransCanada.

TC PipeLines GP, an indirect wholly-owned subsidiary of TransCanada provides certain administrative services for the Partnership and is reimbursed for its costs and expenses. Certain officers of TC PipeLines GP are deemed to be executive officers of the Partnership.

Executive Compensation

The following table summarizes certain information regarding the annual salary of Russell K. Girling, Chief Executive Officer of the general partner of the Partnership effective June 1, 2006, Ronald J. Turner, President and Chief Executive Officer of the general partner of the Partnership for the years ended December 31, 2004, and 2005 and up until May 1, 2006, Gregory A. Lohnes, Chief Financial Officer of the general partner of the Partnership effective June 1, 2006 and Amy W. Leong, Controller and principal financial officer. These salaries are paid by TransCanada, parent company of the general partner. Mr. Girling, Mr. Turner, Mr. Lohnes and Ms. Leong are employees of TransCanada. TC PipeLines reimburses TransCanada for the services contributed to its operations by Mr. Girling, Mr. Turner, Mr. Lohnes and Ms. Leong. Approximately 10 per cent of Mr. Girling s and Mr. Turner s base salary listed in the table below is allocated to the Partnership.

Name and Principal Position	Year	Annual TransCanada Base Salary Canadian Dollars	United States Dollar Equivalent (1)	Total (1)
Russell K. Girling, President and Chief Executive Officer	2006	303,338	260,294	260,294
Ronald J. Turner, President and Chief Executive Officer	2006	450,000	386,145	386,145
	2005	450,000	385,965	385,965
	2004	450,000	374,000	374,000
Gregory A. Lohnes, Chief Financial Officer	2006	331,973	284,866	284,866
Amy W. Leong, Controller and principal financial officer	2006	155,004	133,009	133,009

(1) The compensation of the Chief Executive Officer, Chief Financial Officer and the Principal Financial Officer of the general partner is paid by TransCanada in Canadian dollars. The United States dollar equivalents have been calculated using the applicable December 31, 2006, 2005 and 2004 noon buying rates of 0.8581, 0.8577 and 0.8308, respectively, as reported by the Bank of Canada.

Director 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 $20,000 per annum and an additional fee of $6,000 per annum or $4,000 per annum for chairing the Conflicts Committee and Audit Committee, respectively. These fees are paid by the Partnership on a semi-annual basis. 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. The directors compensation plan which provided for independent directors to receive 50 per cent of their annual board retainer in the form of common units of the Partnership was discontinued at the end of the second quarter of 2005. Under that plan, the purchases were made at the trading price of common units on the day preceding the applicable payment date of the retainer for the benefit of the Partnership s directors.

Name	Fees Earned or Paid in Cash	Total
David L. Marshall	55,500	55,500
Jack F. Jenkins-Stark	55,000	55,000
Walentin (Val) Mirosh	50,000	50,000

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 23, 2007 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.

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Amount and Nature of Beneficial Ownership

Name and Business Address	Common Units (1) Number of Units	Percent of Class
TransCan Northern Ltd. (2) 450 1st Street SW Calgary, Alberta T2P 5H1	8,678,045	24.9
TC Pipelines GP, Inc. (3) (4) 450 1st Street SW Calgary, Alberta T2P 5H1	2,035,106	5.8
David L. Marshall (5) 450 1st Street SW Calgary, Alberta T2P 5H1	1,083	*
Walentin (Val) Mirosh (6) 450 1st Street SW Calgary, Alberta T2P 5H1		
Jack F. Jenkins-Stark (7) 3003 Tasman Drive Santa Clara, CA 95054	3,433	*
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		
Kristine L. Delkus 450 1st Street SW Calgary, Alberta T2P 5H1		
Directors and Executive officers as a Group (8) (9) (13 persons)		*

(1) A total of 34,856,086 common units are issued and outstanding.

(2) TransCan Northern Ltd. is a wholly owned indirect subsidiaries of TransCanada.

(3) TC PipeLines GP, Inc. is a wholly owned indirect subsidiaries of TransCanada.

(4) TC PipeLines GP, Inc. owns an aggregate of 2% general partner interest of TC PipeLines.

(5) 1,083 units are held directly by Mr. Marshall.

(6) No units are currently held by Mr. Mirosh.

(7) 3,433 units are held by the Jenkins-Stark Family Trust dated June 16, 1995.

(8) With the exception of the two named directors above, none of the other directors and executive officers hold

any units of TC PipeLines.

(9) Russell K. Girling holds 275,000 options and 12,565 shares of TransCanada; Kristine L. Delkus holds 73,833 options and 3,461 shares of TransCanda; Steven D. Becker holds 90,000 options and 2,212 shares of TransCanada; Ronald L. Cook holds 66,333 options and 10,403 shares of TransCanada; Gregory A. Lohnes holds 19,500 options and 3,000 shares of TransCanada; Amy W. Leong holds 5,600 options and 3,048 shares of TransCanada; Donald DeGrandis holds 20,776 options and 199 shares of TransCanada; Mark A.P. Zimmerman holds 16,500 options and 373 shares of TransCanada and Sean M.Brett holds 17,300 options and 11,054 shares of TransCanada. The directors and executive officers as a group hold 584,842 options and 46,315 shares of TransCanada. All options listed above are exercisable within 60 days from March 1, 2007.

* Less than 1%.

Item 13. Certain Relationships and Related Transactions

At March 2, 2007, a subsidiary of TransCanada owns 8,678,045 common units and the Partnership s general partner owns 2,035,106 common units representing an aggregate 30.1 per cent limited partner interest in the Partnership. In addition, the

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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 32.1 per cent by virtue of its indirect ownership of the general partner and 30.1 per cent aggregate limited partner interest.

The general partner is accountable to TC PipeLines 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 TC PipeLines, 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, TC PipeLines, 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 TC PipeLines. 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, TC PipeLines. Further, the general partner and its affiliates have no obligation to present business opportunities to TC PipeLines.

- The partnership agreement provides that the general partner and its officers and directors will not be liable for monetary damages to TC PipeLines, 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.

TC PipeLines 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 TC PipeLines. Indemnification is required for criminal proceedings if the General Partner and others had no reasonable cause to believe their conduct was unlawful.

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 or other compensation 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. The partnership agreement provides that the general partner will, in its sole discretion, determine the expenses that are allocable to the Partnership in any reasonable manner determined by it. Total costs reimbursed to the general partner by the Partnership were approximately $1.2 million for the year ended December 31, 2006. Such costs include personnel costs (such as salaries and employee benefits), overhead costs (such as office space and equipment) and out-of-pocket expenses related to the provision of services to the Partnership.

Pursuant to our Partnership agreement, whenever a potential conflict of interest exists or arises between the general partner or any of its affiliates and the Partnership, any resolution or course of action by the general partner or its affiliates in respect of such conflict of interest shall be permitted if the resolution or course of action is deemed to be fair and reasonable to the Partnership. As such, the general partner has established a Conflicts Committee, of not less than two independent directors, to oversee all matters relating to the resolution of conflicts of interest and to provide to our board of directors recommendation for such resolution of conflicts of interest.

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

On April 6, 2006, the Partnership acquired an additional 20 per cent general partnership interest in Northern Border Pipeline. As part of this transaction, the Partnership paid a $10 million transaction fee to a subsidiary of TransCanada, who will become the operator of Northern Border Pipeline in April 2007. This fee has been recorded as part of the Partnership s investment in Northern Border Pipeline and is being amortized over the term of the related operating agreement ending April 1, 2018.

On February 22, 2007, the Partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation. The acquisition was partially financed through a private placement for gross proceeds of $600 million. TransCan Northern Ltd. purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300 million. In 2006, transportation contracts held by TransCanada and ANR Pipeline, its wholly-owned subsidiary, represent approximately 58 per cent of Great Lakes revenue. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the remaining 3.55 per cent interest simultaneously with the Partnership s acquisition of its interest and now owns a controlling interest in Great Lakes. A wholly-owned subsidiary of TransCanada also became the operator of Great Lakes.

Item 14. Principal Accountant Fees and Services

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

	2006		2005	
Audit Fees	167,436	(1)	147,642	(1)
Audit Related Fees (2)				
Tax Fees (2)				
All Other Fees	45,995			

(1) Audit Fees include services performed related to Sarbanes-Oxley Act reporting requirements.

(2) The Partnership has not engaged its external auditors for any audit-related services or tax services in 2006 or 2005.

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 field 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 fess are reviewed and approved by our Audit committee.

PART IV

Item 15. Exhibits and 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	Partnership Interest Purchase and Sale Agreement dated as of December 31, 2005 by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP s Form 8K, February 15, 2006).
*2.2	General Partnership Interest Purchase Agreement dated as of November 1, 2006 by and between Tuscarora Gas Pipeline Co. and TC Tuscarora Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP s Form 8K, November 7, 2006).
*2.3	General Partner Interest Holder Agreement dated as of November 1, 2006 by and between Tuscarora Gas Pipeline Co. and TC Tuscarora Intermediate Limited Partnership (Exhibit 2.2 to TC PipeLines, LP s Form 8K, November 7, 2006).
*2.4	Purchase and Sale Agreement among El Paso Great Lakes Company, L.C.C., as Seller, and TC GL Intermediate Limited Partnership and TransCanada PipeLine USA Ltd., as Buyers dated as of December 22, 2006 (Exhibit 2.1 to TC PipeLines,

	LP s Form 8K, December 26, 2006).
*3.1	Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated May 28, 1999 (Exhibit 3.1 to TC PipeLines, LP s Form 10-K, March 28, 2000).

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*3.2 Certificate of Limited Partnership of TC PipeLines, LP (Exhibit 3.2 to TC PipeLines, LP s Form S-1 Registration Statement, Registration No. 333-69947, December 30, 1998).

*4.1 Indenture, dated as of August 17, 1999 between Northern Border Pipeline Company and Bank One Trust Company, NA, successor to The First National Bank of Chicago, Trustee (Exhibit 4.1 to Northern Border Pipeline Company, Form S-4 Registration Statement, Registration No. 333-88577, October 7, 1999).

*4.2 Indenture, Assignment and Security Agreement dated December 21, 1995 between Tuscarora Gas Transmission Company and Wilmington Trust Company, as trustee (Exhibit 99.1 to TC PipeLines, LP s Form 10-Q, September 30, 2000).

*4.3 Indenture dated September 17, 2001, between Northern Border Pipeline Company and Bank One Trust Company, N.A., Trustee (Exhibit 4.2 to Northern Border Pipeline Company, Form S-4 Registration Statement, Registration No. 333-73282, November 13, 2001).

*4.4 Indenture dated April 29, 2002, between Northern Border Pipeline Company and Bank One Trust Company, NA, Trustee (Exhibit 4.1 to Northern Border Pipeline Company s Form 10-Q, March 31, 2002).

*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, March 28, 2000).

*10.2 Northern Border Pipeline Company General Partnership Agreement between Northern Border Intermediate Limited Partnership, TransCanada Border PipeLine Ltd., and TransCan Northern Ltd., effective March 9, 1978 as amended (Exhibit 3.2 to Northern Border Partners, L.P. Form S-1 Registration Statement No. 33-66158).

*10.2.1 Seventh Supplement Amending Northern Border Pipeline Company General Partnership Agreement dated as of September 23, 1993 (Exhibit 10.3.1 to TC PipeLines, LP s Form S-1, December 30, 1998).

*10.2.2 Eighth Supplement Amending Northern Border Pipeline Company General Partnership Agreement dated May 21, 1999 by and among TransCan Border PipeLine Ltd., TransCanada Northern Ltd., Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (Exhibit 10.3.2 to TC PipeLines, LP s Form 10-K, March 28, 2000).

*10.2.3 Ninth Supplement Amending Northern Border Pipeline Company General Partnership Agreement dated July 16, 2001 by and among Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (Exhibit 10.37 to Northern Border Pipeline Company, Form S-4 Registration Statement, Registration No. 333-73282, November 13, 2001).

*10.2.4 Tenth Supplement Amending Northern Border Pipeline Company General Partnership Agreement dated March 3, 2005 (Exhibit 3.5 to Northern Border Pipeline Form 10-K, December 31, 2004).

*10.3 Renewal of U.S. $40,000,000 Two Year Revolving Credit Facility between TC PipeLines, LP, as borrower, and TransCanada PipeLine USA Ltd., as lender dated May 28, 2003 (Exhibit 10.1 to TC PipeLines, LP s Form 10-Q, August 14, 2003).

*10.4 Operating Agreement between Northern Border Pipeline Company and Northern Plains Natural Gas Company, dated February 28, 1980 (Exhibit 10.3 to Northern Border Partners, L.P. s Form S-1 Registration Statement No. 33-66158, July 16, 1993).

*10.4.1 Consent and Amendment to Operating Agreement by and between Northern Border Pipeline Company and Northern Plains Natural Gas Company, LLC, dated April 6, 2006 (Exhibit 10.1 to Northern Border Pipeline Company s Form 8K, Registration No. 333-88577, April 12, 2006).

*10.5 Northern Border Pipeline Agreement among Northern Plains Natural Gas Company, Pan Border Gas Company, Northwest Border Pipeline Company, TransCanada Border PipeLine Ltd., TransCan Northern Ltd., Northern Border Intermediate Limited Partnership, Northern Border Partners, L.P., and the Management Committee of Northern Border Pipeline, dated as of March 17, 1999 (Exhibit 10.21 to Northern Border Partners, L.P. s 1998 Form 10-K/A, March 24, 1999).

*10.6 Revolving Credit Agreement, dated as of May 16, 2005, among Northern Border Pipeline Company, the lenders from time to time party thereto, Wachovia Bank, National Association, as Administrative Agent, SunTrust Bank, as syndication agent, Harris Nesbit Financing, Inc., Barclays Bank PLC and Citibank, N.A., as co-documentation 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 8-K, File No. 333-88577, May 20, 2005).

*10.7 First Amendment to Revolving Credit Agreement dated as of March 29, 2006 among Northern Border Pipeline Company, the lenders from time to time party thereto, Wachovia Bank, National Association, as Administrative Agent; SunTrust Bank, as syndication agent; and Harris Nesbit Financing, Inc., Barclays Bank PLC and Citibank, N.A., as co-documentation agents (Exhibit 10.1 to Northern Border Pipeline Company s Form 8K, File No. 333-88577, April 4, 2006).

*10.8 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).

*10.9 Form of Contribution, Conveyance and Assumption Agreement among TC PipeLines, L.P., and Northern Border Intermediate Limited Partnership. (Exhibit 10.2 to TC PipeLines, L.P. s Form S-1/A, May 3, 2000).

*10.10 Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. (Exhibit 10.2 to Northern Border Pipeline Company s Form 8K, File No. 333-88577, April 12, 2006).

10.11 Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated as of December 19, 2006

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 and financial statement schedule of Northern Border Pipeline Company

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.

* Indicates exhibits incorporated by reference.

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 2nd day of March 2007.

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/ Amy W. Leong
	Amy W. Leong 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)	March 2, 2007
/s/	Amy W. Leong Amy W. Leong	Controller and Principal Financial Officer	March 2, 2007
/s/	Gregory A. Lohnes Gregory A. Lohnes	Director	March 2, 2007
/s/	Kristine L. Delkus Kristine L. Delkus	Director	March 2, 2007
	Steven D. Becker	Director	
/s/	Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	March 2, 2007
/s/	Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	March 2, 2007
	David L. Marshall	Director	

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To 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) as of December 31, 2006 and 2005 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, 2006. These consolidated financial statements are the responsibility of the General Partner 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 standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our 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 TC PipeLines, LP as of December 31, 2006 and 2005 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006 in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of TC PipeLines, LP s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission* (COSO), and our report dated February 27, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

Calgary, Canada
February 27, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP:

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control over Financial Reporting appearing under Item 9A, that TC PipeLines, LP maintained effective internal control over financial reporting as of December 31, 2006 based on the 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 maintaining effective internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Partnership s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting , evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and the receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; 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, management s assessment that TC PipeLines, LP maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of Treadway Commission* (COSO). Also, in our opinion, TC PipeLines, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of Treadway Commission* (COSO).

TC PipeLines, LP acquired an additional 49 % interest in Tuscarora Gas Transmission Company during 2006, and management excluded from its assessment of the effectiveness of TC PipeLines, LP s internal control over financial reporting as of December 31, 2006, Tuscarora Gas Transmission Company s internal control over financial reporting associated with assets representing 17 % of consolidated total assets and 14 % of consolidated net income of TC PipeLines, LP as of and for the year ended December 31, 2006. Our audit of internal control over financial reporting of TC PipeLines, LP also excluded an evaluation of the internal control over financial reporting of Tuscarora Gas Transmission Company.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TC PipeLines, LP as of December 31, 2006 and 2005 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, 2006 and our report dated February 27, 2007 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Calgary, Canada
February 27, 2007

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2006**	**2005**
Assets		
Current assets		
Cash and short-term investments	**4.0**	2.3
Accounts receivable and other	**2.5**	
	6.5	2.3
Investment in Northern Border Pipeline *(Note 3)*	**561.2**	274.5
Investment in Tuscarora *(Note 4)*		38.9
Plant, property and equipment *(Note 5)*	**127.0**	
Goodwill *(Note 6)*	**79.2**	
Other assets	**3.9**	
	777.8	315.7
Liabilities and Partners Equity		
Current liabilities		
Accounts payable	**3.3**	0.5
Accrued interest	**1.3**	0.1
Current portion of long-term debt *(Note 7)*	**4.7**	13.5
	9.3	14.1
Long-term debt *(Note 7)*	**463.4**	
	472.7	14.1
Non-controlling interests *(Note 6)*	**1.2**	
Partners equity *(Note 8)*		
Common units	**295.6**	294.4
General partner	**6.5**	6.5
Accumulated other comprehensive income	**1.8**	0.7
	303.9	301.6
	777.8	315.7

Commitments and contingences *(Note 16)*

Subsequent events *(Note 17)*

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

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TC PIPELINES, LP
CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 **(millions of dollars except per unit amounts)**	**2006**	**2005**	**2004**
Equity income from investment in Northern Border Pipeline *(Note 3)*	**56.6**	45.7	50.0
Equity income from investment in Tuscarora *(Note 4)*	**5.9**	7.5	7.5
Transmission revenues	**0.9**		
Operations, maintenance and administrative expenses	**(2.7)**	(2.0)	(1.9)
Depreciation	**(0.2)**		
Financial charges, net and other *(Note 9)*	**(15.8)**	(1.0)	(0.5)
Net income	**44.7**	50.2	55.1
Net income per unit *(Note 10)*	**$ 2.39**	$ 2.70	$ 2.99
Units outstanding *(millions)*	**17.5**	17.5	17.5

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 **(millions of dollars)**	**2006**	**2005**	**2004**
Net income	**44.7**	50.2	55.1
Other comprehensive income			
Change associated with current period hedging transactions *(Note 15)*	**1.6**		
Change associated with current period hedging transactions of investees	**(0.5)**	(0.5)	(0.4)
Total Comprehensive Income	**45.8**	49.7	54.7

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

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TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2006**	**2005**	**2004**
Cash Generated From Operations			
Net income	**44.7**	50.2	55.1
Depreciation	**0.2**		
Amortization of other assets *(Note 9)*	**0.9**		
(Increase)/decrease in operating working capital	**0.3**	(0.1)	0.1
	46.1	50.1	55.2
Investing Activities			
Return of capital from Northern Border Pipeline	**23.8**	15.2	11.7
Return of capital from Tuscarora	**1.8**	0.8	0.4
Investment in Northern Border Pipeline *(Note 3)*	**(311.1)**		(61.5)
Investment in Tuscarora, net of cash acquired *(Note 4)*	**(97.2)**	(0.3)	
Increase in cash due to the consolidation of Tuscarora *(Note 6)*	**2.6**		
Other assets	**(1.9)**		
	(382.0)	15.7	(49.4)
Financing Activities			
Distributions paid *(Note 11)*	**(43.5)**	(43.0)	(41.8)
Long-term debt issued *(Note 7)*	**707.0**		37.0
Long-term debt repaid *(Note 7)*	**(325.9)**	(23.0)	(6.0)
	337.6	(66.0)	(10.8)
Increase/(decrease) in cash and short-term investments	**1.7**	(0.2)	(5.0)
Cash and short-term investments, beginning of year	**2.3**	2.5	7.5
Cash and short-term investments, end of year	**4.0**	2.3	2.5
Interest payments made	13.9	1.0	0.5

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

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TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS EQUITY

	Common Units (millions of units)	(millions of dollars)	Subordinated Units (millions of units)	(millions of dollars)	General Partner (millions of dollars)	Accumulated Other Comprehensive Income (millions of dollars)	Partners (millions of units)	Equity (millions of dollars)
Partners equity at December 31, 2003	16.5	260.4	1.0	13.9	6.1	1.6	17.5	282.0
Net income		51.0		1.4	2.7			55.1
Distributions paid		(37.8)		(1.5)	(2.5)			(41.8)
Subordinated unit conversion	1.0	13.8	(1.0)	(13.8)				
Other comprehensive income						(0.4)		(0.4)
Partners equity at December 31, 2004	17.5	287.4			6.3	1.2	17.5	294.9
Net income		47.3			2.9			50.2
Distributions paid		(40.3)			(2.7)			(43.0)
Other comprehensive income						(0.5)		(0.5)
Partners equity at December 31, 2005	17.5	294.4			6.5	0.7	17.5	301.6
Net income		41.8			2.9			44.7
Distributions paid		(40.6)			(2.9)			(43.5)
Other comprehensive income						1.1		1.1
Partners equity at December 31, 2006	**17.5**	**295.6**			**6.5**	**1.8**	**17.5**	**303.9**

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

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TC PIPELINES, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP, and its subsidiary limited partnerships, TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership, all Delaware limited partnerships, are collectively referred to herein as TC PipeLines or the Partnership. TC PipeLines was formed by TransCanada PipeLines Limited, a subsidiary of TransCanada Corporation (collectively referred to herein as TransCanada), to acquire, own and participate in the management of United States (U.S.) -based pipeline assets.

TC PipeLines, through TC PipeLines Intermediate Limited Partnership, owns a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border Pipeline), a Texas general partnership. Northern Border Pipeline 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.

TC PipeLines also, through TC Tuscarora Intermediate Limited Partnership, owns or controls a 99 per cent general partner 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 (GTN), a wholly-owned subsidiary of TransCanada, to northern Nevada.

TC PipeLines is managed by its general partner, TC PipeLines GP, Inc., an indirect wholly-owned subsidiary of TransCanada. The general partner provides certain administrative services for the Partnership and is reimbursed for its costs and expenses. In addition to its aggregate 2 per cent general partner interest in TC PipeLines, LP and its subsidiary limited partnership on a combined basis, the general partner owns 2,035,106 common units, representing an effective 7.7 per cent limited partner interest in the Partnership at December 31, 2006.

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, 2006 and 2005 and the results of its operations, cash flows and changes in partners equity for the years ended December 31, 2006, 2005 and 2004. The Partnership uses the equity method of accounting for its investment in Northern Border Pipeline, over which it is able to exercise significant influence. TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006. On this date, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora and as a result of acquiring a controlling interest in Tuscarora, began to consolidate Tuscarora s operations. 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 Short-Term Investments

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 relates solely to Tuscarora as is stated at original cost. Costs of migrating 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 of 30 years and of the compression equipment of

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25 years. Equipment is depreciated on a straight-line basis over the estimated useful lives of the equipment which range from three to 30 years. Repair and maintenance costs are expensed as incurred. Costs that are considered a betterment are capitalized.

Long-lived assets are assessed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amounts of such assets exceed the fair value of the assets.

(e) Partners Equity

Costs incurred in connection with the issuance of units are deducted from the proceeds received. Costs incurred to convert subordinated units to common units are deducted from partners equity.

(f) Revenue Recognition

Transmission revenues are recognized in the period in which the service is provided. When rate cases are pending final FERC approval, a portion of revenue collected is subject to possible refund. As of December 31, 2006, the Partnership has not recognized any transmission revenue that is subject refund.

(g) Income Taxes

As a partnership, TC PipeLines 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 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 but is amortized for tax purposes. Goodwill is re-evaluated on an annual basis for impairment.

(i) Derivative Financial Instruments and Hedging Activities

The Company utilizes derivative and other financial instruments to manage its exposure to changes in interest rates. Derivatives and other instruments must be designated and be effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. 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 deferred and 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

SFAS No. 143, *Accounting for Asset Retirement 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 SFAS No. 143 are those for which a legal

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obligation exists under enacted laws, statutes, ordinances, or written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The plant, property and equipment of Tuscarora consist primarily of underground pipelines and above ground compression equipment and other facilities. No amount has been recorded for asset retirement obligations relating to these assets based on management s assessment that no legal obligation exists.

NOTE 3 INVESTMENT IN NORTHERN BORDER PIPELINE

The Partnership owns a 50 per cent general partner interest in Northern Border Pipeline. The remaining 50 per cent partnership interest in Northern Border Pipeline is held by ONEOK Partners, LP (ONEOK), a publicly traded limited partnership. The Northern Border Pipeline system is operated by ONEOK Partners GP, LLC (ONEOK Partners GP), a wholly-owned subsidiary of ONEOK. Northern Border Pipeline is regulated by the Federal Energy Regulatory Commission (FERC).

TC PipeLines Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Northern Border Pipeline. TC PipeLines, LP holds a 98.9899 per cent limited partnership interest in TC PipeLines Intermediate Limited Partnership. See Note 9 Commitments and Contingencies to the Northern Border Pipeline s Financial Statements included elsewhere in this report.

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border Pipeline. The Partnership uses the equity method of accounting for its investment in Northern Border Pipeline. TC PipeLines equity income for the year ended December 31, 2006 includes 30 per cent of the net income of Northern Border Pipeline up to April 6, 2006 and 50 per cent thereafter. TC PipeLines equity income from its investment in Northern Border Pipeline amounted to $56.6 million, $45.7 million and $50.0 million for the years ended December 31, 2006, 2005 and 2004, respectively. Northern Border Pipeline had no undistributed earnings for the years ended December 31, 2006, 2005 and 2004, respectively.

The following sets out summarized financial information for Northern Border Pipeline as at December 31, 2006 and 2005 and for the years ended December 31, 2006, 2005 and 2004:

Summarized Northern Border Pipeline Balance Sheet

December 31 **(millions of dollars)**	**2006**	**2005**
Assets		
Cash and cash equivalents	**11.0**	22.0
Other current assets	**35.5**	45.7
Plant, property and equipment, net	**1,475.7**	1,516.1
Other assets	**22.5**	20.9
	1,544.7	1,604.7
Liabilities and Partners Equity		
Current liabilities	**47.7**	56.0
Long-term debt, including current maturities	**619.8**	628.9
Reserves and deferred credits	**2.1**	4.8
Partners equity		
Partners capital	**874.1**	912.7
Accumulated other comprehensive income	**1.0**	2.3
	1,544.7	1,604.7

Summarized Northern Border Pipeline Income Statement

Year ended December 31 (millions of dollars)	2006	2005	2004
Revenues	**310.9**	321.7	329.1
Costs and expenses	**(81.0)**	(70.8)	(63.2)
Depreciation	**(58.7)**	(58.1)	(58.3)
Financial charges	**(43.1)**	(42.6)	(41.3)
Other income	**1.8**	2.1	0.5
Net income	**129.9**	152.3	166.8

NOTE 4 INVESTMENT IN TUSCARORA

On September 1, 2000, the Partnership acquired its initial 49 per cent interest in Tuscarora from a subsidiary of TransCanada. Tuscarora is regulated by the FERC. TC PipeLines equity income from its investment in Tuscarora amounted to $5.9 million, $7.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. Tuscarora had no undistributed earnings for the years ended December 31, 2006, 2005 and 2004, respectively.

On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. Prior to the acquisition, the Partnership used the equity method of accounting for its investment in Tuscarora. Subsequent to the acquisition, the Partnership used the consolidation method of accounting for its investment in Tuscarora. At December 31, 2006, the Partnership owns a 98 per cent general partner interest in Tuscarora. The remaining general partner interests in Tuscarora are held one per cent by Sierra Pacific Resources and one per cent by TransCanada. The Partnership recorded net income from Tuscarora under the consolidation method of $0.4 million for the period December 19, 2006 to December 31, 2006.

The following sets out summarized financial information for Tuscarora as at December 31, 2006 and 2005 and for the years ended December 31, 2006, 2005 and 2004:

Summarized Tuscarora Balance Sheet

December 31 (millions of dollars)	2006	2005
Assets		
Cash and cash equivalents	**2.2**	3.8
Other current assets	**2.5**	3.0
Plant, property and equipment, net	**127.0**	131.6
Other assets	**1.2**	1.4
	132.9	139.8
Liabilities and Partners Equity		
Current liabilities	**2.4**	6.8
Long-term debt	**71.1**	71.1
Partners equity		
Partners capital	**59.3**	61.8
Accumulated other comprehensive income	**0.1**	0.1
	132.9	139.8

Summarized Tuscarora Income Statement

Year ended December 31 (millions of dollars)	2006	2005	2004
Revenues	**29.5**	32.3	32.6
Costs and expenses	**(4.7)**	(4.4)	(4.9)
Depreciation	**(6.2)**	(6.2)	(6.1)
Financial charges	**(5.5)**	(5.8)	(6.1)
Other income	**0.2**	0.2	0.8
Net income	**13.3**	16.1	16.3

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

December 31, 2006 (millions of dollars)	Cost	Accumulated Depreciation	Net Book Value
Tuscarora			
Pipeline facilities	160.1	51.9	108.2
Compression equipment	20.9	3.5	17.4
Construction work in progress	1.3		1.3
Plant held for future use	0.1		0.1
	182.4	**55.4**	**127.0**

NOTE 6 ACQUISITIONS

Northern Border Pipeline

On April 6, 2006, the Partnership acquired an additional 20 per cent general partnership interest in Northern Border Pipeline for approximately $297 million plus a $10 million transaction fee payable to a subsidiary of TransCanada, bringing the Partnership s total interest to 50 per cent. Through the acquisition, TC PipeLines indirectly assumed approximately $120 million of debt. The Partnership funded the transaction through a Bridge Loan Credit Facility. In connection with this transaction, a subsidiary of TransCanada will become the operator of Northern Border Pipeline in April 2007.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated using an estimate of fair value of the net assets at the date of acquisition. The difference between the purchase price and the fair value of net assets of $114 million, being goodwill, was recorded as part of the Partnership s investment in Northern Border Pipeline. The $10 million transaction fee payable to a subsidiary of TransCanada, who will become the operator of Northern Border Pipeline in April 2007, has been recorded as part of the Partnership s investment in Northern Border Pipeline and is being amortized over the term of the related operating agreement.

Tuscarora

On December 19, 2006, the Partnership acquired an additional 49 per cent general partnership interest in Tuscarora for $99.9 million, subject to closing adjustments. Through the acquisition TC PipeLines indirectly assumed $37.5 million of Tuscarora debt. The Partnership funded the transaction through the Senior Credit Facility. In connection with this transaction, a subsidiary of TransCanada became the operator of Tuscarora.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated as follows using an estimate of fair value of the assets acquired and liabilities assumed at the date of acquisition:

Purchase Price Allocation (millions of dollars)	Acquisition of additional 49% interest
Current assets	4.7
Plant, property and equipment	56.6
Other non-current assets	0.7
Goodwill	79.2
Current liabilities	(2.6)
Long-term debt	(37.5)
Non-controlling interests	(1.2)
	99.9

Tuscarora s business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Tuscarora were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisition.

Pro forma financial information for the Northern Border Pipeline and Tuscarora acquisitions

The following unaudited pro forma financial information for the year ended December 31, 2006 has been prepared as if the acquisitions occurred on January 1, 2006:

Year ended December 31 (millions of dollars except per unit amounts)	2006
Equity income from investment in Northern Border Pipeline	**64.1**
Transmission revenues	**29.5**
Net income	**51.0**
Net income per unit	**$ 2.74**

NOTE 7 CREDIT FACILITIES AND LONG-TERM DEBT

(millions of dollars)	2006	2005
Senior Credit Facility	**397.0**	
Series A Senior Notes	**57.9**	
Series B Senior Notes	**6.0**	
Series C Senior Notes	**7.2**	
Revolving Credit Facility		13.5
Total	**468.1**	13.5

On February 28, 2006, the Partnership renewed a $20.0 million, previously $30.0 million, unsecured credit facility (Revolving Credit Facility). Loans under the Revolving Credit Facility bore interest, at the option of the Partnership, at a one-, two-, three-, or six-month London interbank offered rate (LIBOR) plus 0.75 per cent or 1.00 per cent if total debt was less than 15 per cent of capitalization, or greater than or equal to 15 per cent of capitalization, respectively, or at a floating rate based on the higher of the federal funds effective rate plus 0.5 per cent and the prime rate. In 2005, the Partnership repaid $16.5 million on the Revolving Credit Facility and had $13.5 million outstanding at December 31, 2005. In 2006, TC PipeLines repaid the Revolving Credit Facility in full and it was terminated. The interest rate on the Revolving Credit Facility averaged 5.60 per cent and 4.40 per cent for the years ended December 31, 2006 and 2005, respectively, and at December 31, 2005 the interest rate was 5.62 per cent.

On March 31, 2006, the Partnership entered into an unsecured credit agreement for a $310 million credit facility (Bridge Loan Credit Facility) with a banking syndicate. Borrowings under the Bridge Loan Credit Facility bore interest, at the option of the Partnership, at the LIBOR or the base rate plus an applicable margin. On April 5, 2006, the Partnership borrowed $307 million under the Bridge Loan Credit Facility to finance the purchase price and a $10 million transaction fee payable in connection with the acquisition of an additional 20 per cent general partnership interest in Northern Border Pipeline. The remaining $3 million commitment under the Bridge Loan Credit Facility was terminated. On December 12, 2006, the Bridge Loan Credit Facility was refinanced through a $297 million draw on a $410 million credit agreement (Senior Credit Facility) with a banking syndicate and the use of $10 million cash on hand. The interest rate on the Bridge Loan Credit Facility averaged 6.29 per cent for the year ended December 31, 2006.

On December 12, 2006, the Partnership entered into a credit agreement for the Senior Credit Facility. On December 19, 2006, TC PipeLines borrowed an additional $100 million under the Senior Credit Facility to finance the purchase price of an additional 49% general partner interest in Tuscarora. The Senior Credit Facility matures on December 12, 2011, at which time all amounts outstanding will be due and payable. Amounts borrowed may be repaid in part or in full prior to that time without penalty. Borrowings under the Senior Credit Facility will bear interest based, at the Partnership s election, on the LIBOR or the prime rate plus, in either case, an applicable margin. There was $397 million outstanding under the Senior Credit Facility at December 31, 2006. The interest rate on the Senior Credit Facility averaged 6.16 per cent for the year ended December 31, 2006 and at December 31, 2006, the interest rate was 6.07 per cent. At December 31, 2006, the Partnership was in compliance with its financial covenants.

On December 21, 1995, Tuscarora issued $91.7 million of 7.13% senior secured notes, which require principal and interest payments over 15 years and mature on December 21, 2010 (Series A). On December 21, 2000, Tuscarora issued $8.0 million of 7.99% senior secured notes, which require principal and interest payments over ten years and mature on December 21, 2010 (Series B). On March 15, 2002, Tuscarora issued $10.0 million of 6.89% senior secured notes, which require principal and interest payments over ten years and mature on December 21, 2012 (Series C). The Series A, Series B and Series C notes (collectively, the Notes) have a final payment at maturity of $46.7 million, $4.1 million and $2.7 million, respectively. The Notes are secured by Tuscarora s transportation contracts, supporting agreements and substantially all of Tuscarora s property. The credit agreement for the Notes contains certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners.

Annual maturities of the Senior Credit Facility and the Notes are summarized as follows (*millions of dollars*):

2007	4.7
2008	4.6
2009	4.4
2010	53.5
2011	397.8
Thereafter	3.1
	468.1

NOTE 8 PARTNERS CAPITAL

Partners capital consists of 17,500,000 common units representing an aggregate 98 per cent limited partner interest in the Partnership (which number includes 2,035,106 common units held by the general partner) and an aggregate two per cent general partner interest. In aggregate the general partner s interests represent an effective 13.4 per cent ownership in the Partnership.

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NOTE 9 FINANCIAL CHARGES, NET AND OTHER

Year ended December 31 (millions of dollars)	2006	2005	2004
Interest expense on long-term debt	**14.8**		0.5
Interest expense on short-term debt	**0.3**	1.1	
Interest income	**(0.4)**	(0.1)	(0.1)
Amortization of other assets	**0.9**		
Other	**0.2**		0.1
	15.8	1.0	0.5

NOTE 10 NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deduction of the general partner s allocation, by the weighted average number of common and subordinated units outstanding. The general partner s allocation is equal to an amount based upon the general partner s two per cent interest, adjusted to reflect an amount equal to incentive distributions. Net income per unit was determined as follows:

Year ended December 31 (millions of dollars except per unit amounts)	2006	2005	2004
Net income	**44.7**	50.2	55.1
Net income allocated to general partner			
General partner interest	**(0.9)**	(1.0)	(1.0)
Incentive distribution income allocation	**(2.0)**	(1.9)	(1.7)
	(2.9)	(2.9)	(2.7)
Net income allocable to units	**41.8**	47.3	52.4
Weighted average units outstanding *(millions)*	**17.5**	17.5	17.5
Net income per unit	**$ 2.39**	$ 2.70	$ 2.99

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, 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 $0.60 per unit if and to the extent there is sufficient available cash. Common units will not accrue arrearages with respect to distributions for any quarter after the subordination period.

As an incentive, the general partner s percentage interest in quarterly distributions is increased after certain specified target levels are met. The incremental incentive distributions payable to the General Partner are 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, respectively, per unit. For the years ended December 31, 2006, 2005 and 2004, the Partnership distributed $2.325, $2.30 and $2.275, respectively, per unit. The distributions for the year ended December 31, 2006, 2005 and 2004 included incentive distributions to the general partner in the amount of $2.0 million, $1.9 million and $1.7 million, respectively. 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 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 or other compensation 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. The Partnership Agreement provides that the general partner will determine the expenses that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs reimbursed to the general partner by the Partnership were approximately $1.2 million, $1.1 million and $0.9 million for the years ended December 31, 2006, 2005 and 2004, respectively. Such costs include (i) personnel costs (such as salaries and employee benefits), (ii) overhead costs (such as office space and equipment) and (iii) out-of-pocket expenses related to the provision of such services.

On April 6, 2006, the Partnership acquired an additional 20 per cent general partnership interest in Northern Border Pipeline. As part of this transaction, the Partnership paid a $10 million transaction fee to a subsidiary of TransCanada, who will become the operator of Northern Border Pipeline in April 2007. This fee has been recorded as part of the Partnership s investment in Northern Border Pipeline and is being amortized over the term of the related operating agreement.

NOTE 13 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected financial data for the four quarters of each of 2006 and 2005.

Quarter ended **(millions of dollars except per unit amounts)**	**Mar 31**	**Jun 30**	**Sep 30**	**Dec 31**
2006				
Transmission revenues				**0.9**
Equity income	**13.2**	**13.9**	**17.9**	**17.5**
Net income	**12.4**	**9.0**	**12.0**	**11.3**
Net income per unit	**$ 0.67**	**$ 0.47**	**$ 0.65**	**$ 0.60**
Cash distributions paid	**10.7**	**10.8**	**10.7**	**11.3**
2005				
Transmission revenues				
Equity income	14.2	10.4	15.6	13.0
Net income	13.4	9.7	14.8	12.3
Net income per unit	$ 0.72	$ 0.52	$ 0.81	$ 0.65
Cash distributions paid	10.7	10.8	10.7	10.8

NOTE 14 CAPITAL REQUIREMENTS

The Partnership contributed $3.1 million during 2006, representing its then 30 per cent share of a $10.3 million cash call issued by Northern Border Pipeline. The funds were used by Northern Border Pipeline to fund an expansion project.

NOTE 15 FINANCIAL INSTRUMENTS

The carrying value of cash and short-term investments, accounts receivable and other, accounts payable 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 current borrowing rates.

The estimated fair values of the Partnership s and its subsidiary s long-term debt as of December 31, 2006 are as follows:

(millions of dollars)	Carrying Value	Fair Value
Senior Credit Facility	397.0	397.0
Series A Senior Notes	57.9	60.9
Series B Senior Notes	6.0	6.4
Series C Senior Notes	7.2	7.5
Total	468.1	471.8

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

At December 31, 2006, the fair value of the interest rate swaps accounted for as hedges was $1.6 million. The fair value of interest rate derivatives has been calculated using year-end market rates. The notional amount hedged was $200 million. The interest rate swaps are structured such that the cash flows match those of the Senior Credit Facility from March 12, 2007 to December 12, 2011.

NOTE 16 COMMITMENTS AND CONTINGENCIES

At December 31, 2006, Tuscarora is party to a contract with a third party for maintenance services on certain components of pipeline equipment. The contract requires payments of approximately $0.7 million in 2007 and expires in November 2007. In 2006, Tuscarora paid $0.8 million under this contract.

NOTE 17 SUBSEQUENT EVENTS

On January 18, 2007, the Board of Directors of the general partner declared the Partnership s 2006 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 14, 2007 to unitholders of record as of January 31, 2007, totaled $11.3 million and was paid in the following manner: $10.5 million to common unitholders (including $1.2 million to the general partner as holder of 2,035,106 common units), $0.6 million to the general partner as holder of the incentive distribution rights, and $0.2 million to the general partner in respect of its two per cent general partner interest.

Northern Border Pipeline declared and paid a distribution of approximately $44.4 million on February 1, 2007, where the Partnership received its 50 per cent share of $22.2 million.

On February 22, 2007, the Partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation. The total purchase price was $962 million, subject to certain closing adjustments, and included the indirect assumption of approximately $212 million of debt. The acquisition was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600 million which closed concurrently with the acquisition. TransCan Northern Ltd. purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300 million. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with the acquisition. The amount available under the senior credit facility increased from $410 million to $950 million, consisting of a $700 million senior term loan and a $250 million senior revolving credit facility, with $194 million of the senior term loan available being terminated upon closing of the acquisition. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private equity placement.

TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the remaining 3.55 per cent interest simultaneously with the Partnership s acquisition of its interest. A wholly-owned subsidiary of TransCanada also became the operator of Great Lakes. The Partnership used the equity method of accounting for its interest in Great Lakes at the date of acquisition.

Report of Independent Registered Public Accounting Firm

Northern Border Pipeline Company:

We have audited the accompanying balance sheets of Northern Border Pipeline Company (the Company) as of December 31, 2006 and 2005, 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, 2006. 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included 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 of 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, 2006 and 2005, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Omaha, Nebraska
February 27, 2007

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NORTHERN BORDER PIPELINE COMPANY

BALANCE SHEETS

	December 31, 2006 (In thousands)	2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,997	$ 22,039
Accounts receivable	30,073	38,252
Related party receivables	355	2,294
Materials and supplies, at cost	3,970	3,566
Prepaid expenses and other	1,118	1,540
Total current assets	46,513	67,691
Property, plant and equipment:		
In service natural gas transmission plant	2,488,765	2,463,555
Construction work in progress	2,522	13,260
Total property, plant and equipment	2,491,287	2,476,815
Less: Accumulated provision for depreciation and amortization	1,015,646	960,740
Property, plant and equipment, net	1,475,641	1,516,075
Other assets:		
Regulatory assets (Note 2)	19,144	17,422
Unamortized debt expense	3,284	3,434
Other	109	76
Total other assets	22,537	20,932
Total assets	$ 1,544,691	$ 1,604,698
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt (Note 7)	$ 150,000	$
Notes payable (Note 6)	20,000	27,000
Accounts payable	4,577	10,550
Related party payables	2,539	3,555
Accrued taxes other than income	27,571	27,637
Accrued interest	11,515	11,525
Other	1,511	2,755
Total current liabilities	217,713	83,022
Long-term debt, net of current maturities (Note 7)	449,844	601,916
Reserves and deferred credits	2,099	4,775
Commitments and contingencies (Note 9)		
Partners equity:		
Partners capital	874,057	912,723
Accumulated other comprehensive income	978	2,262
Total partners equity	875,035	914,985
Total liabilities and partners equity	$ 1,544,691	$ 1,604,698

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

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NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

	Years Ended December 31, 2006	2005	2004
	(In thousands)		
Operating revenue	$ 310,900	$ 321,651	$ 329,115
Operating expenses			
Operations and maintenance	49,500	39,506	33,763
Depreciation and amortization	58,721	58,052	58,375
Taxes other than income	31,541	31,345	29,368
Operating expenses	139,762	128,903	121,506
Operating income	171,138	192,748	207,609
Interest expense			
Interest expense	43,218	42,792	41,374
Interest expense capitalized	(137)	(157)	(18)
Interest expense, net	43,081	42,635	41,356
Other income (expense)			
Allowance for equity funds used during construction	192	269	31
Other income (Note 12)	2,218	2,396	2,552
Other expense (Note 12)	(622)	(532)	(2,059)
Other income, net	1,788	2,133	524
Net income to partners	$ 129,845	$ 152,246	$ 166,777

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31, 2006	2005	2004
	(In thousands)		
Net income to partners	$ 129,845	$ 152,246	$ 166,777
Other comprehensive income:			
Changes associated with current period hedging transactions	(1,284)	(1,500)	(1,440)
Total comprehensive income	$ 128,561	$ 150,746	$ 165,337

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2006	2005	2004
	(In thousands)		
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	$ 129,845	$ 152,246	$ 166,777
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	59,325	58,404	58,740
Allowance for equity funds used during construction	(192)	(269)	(31)
Changes in components of working capital	1,827	(127)	(12,611)
Other	(5,479)	(3,793)	(6,726)
Total adjustments	55,481	54,215	39,372
Net cash provided by operating activities	185,326	206,461	206,149
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	(20,857)	(28,555)	(10,569)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	10,330		205,000
Distributions to partners	(178,841)	(202,901)	(205,635)
Issuance of debt	105,000	136,000	107,000
Retirement of debt	(112,000)	(109,000)	(313,000)
Proceeds upon termination of derivatives			7,575
Debt reacquisition costs			(4,897)
Long term debt financing costs		(321)	
Net cash used in financing activities	(175,511)	(176,222)	(203,957)
Net change in cash and cash equivalents	(11,042)	1,684	(8,377)
Cash and cash equivalents at beginning of year	22,039	20,355	28,732
Cash and cash equivalents at end of year	$ 10,997	$ 22,039	$ 20,355
Supplemental disclosures for cash flow information:			
Cash paid for interest, net of amount capitalized	$ 45,170	$ 44,067	$ 41,098
Changes in components of working capital:			
Accounts receivable and related party receivables	$ 10,118	$ (6,677)	$ (2,969)
Materials and supplies	(404)	(157)	697
Prepaid expenses and other	422	149	578
Accounts payable and other current liabilities	(8,233)	5,874	(9,731)
Accrued taxes other than income	(66)	524	(1,834)
Accrued interest	(10)	160	648
Total	$ 1,827	$ (127)	$ (12,611)

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

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NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CHANGES IN PARTNERS EQUITY

	TC PipeLines Intermediate Limited Partnership (In thousands)	ONEOK Partners Intermediate Limited Partnership	Accumulated Other Comprehensive Income	Total Partners Equity
Partners equity at December 31, 2003	$ 239,171	$ 558,065	$ 5,202	$ 802,438
Net income to partners	50,033	116,744		166,777
Changes associated with current period hedging transactions			(1,440)	(1,440)
Equity contributions received	61,500	143,500		205,000
Distributions paid	(61,690)	(143,945)		(205,635)
Partners equity at December 31, 2004	289,014	674,364	3,762	967,140
Net income to partners	45,674	106,572		152,246
Changes associated with current period hedging transactions			(1,500)	(1,500)
Distributions paid	(60,870)	(142,031)		(202,901)
Partners equity at December 31, 2005	273,818	638,905	2,262	914,985
Net income to partners	57,452	72,393		129,845
Changes associated with current period hedging transactions			(1,284)	(1,284)
Equity contributions received	3,099	7,231		10,330
Distributions paid	(80,420)	(98,421)		(178,841)
Ownership change	183,080	(183,080)		
Partners equity at December 31, 2006	$ 437,029	$ 437,028	$ 978	$ 875,035

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

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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. In April 2006, ONEOK Partners completed the sale of a 20 percent partnership interest in us to TC PipeLines. ONEOK Partners and TC PipeLines each own a 50 percent interest in us. As a result of the transaction, our General Partnership Agreement was amended and restated effective April 6, 2006.

The ownership percentages of our partners at December 31, 2006 and 2005 are as follows:

	Ownership and Voting Percentage			
Partner	**2006**		**2005**	
ONEOK Partners	50	%	70	%
TC PipeLines	50	%	30	%

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.

The day-to-day management of our affairs is the responsibility of ONEOK Partners GP until March 31, 2007, pursuant to an operating agreement between us and ONEOK Partners GP. ONEOK Partners GP also utilizes ONEOK and its affiliates for management services related to us. We are charged for the salaries, benefits and expenses of ONEOK Partners GP, ONEOK and its affiliates attributable to our operations. For the years ended December 31, 2006, 2005, and 2004, our charges from ONEOK Partners GP and its current and former affiliates totaled approximately $26.2 million, $20.1 million and $18.3 million, respectively. Effective April 1, 2007, TransCan will become our operator under a new operating agreement.

See Note 13 for a discussion of our previous relationships with Enron and developments involving Enron.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with GAAP 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 FERC. Our accounting policies conform to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Accordingly, certain assets that result from the regulated ratemaking process are reflected on the balance sheets as regulatory assets.

At December 31, 2006 and 2005, we have reflected regulatory assets of approximately $19.1 million and $17.4 million, respectively, on the balance sheets. These assets are being amortized as directed by the FERC in our current or previous regulatory proceedings over varying time periods up to 44 years.

The following table presents a summary of regulatory assets, net of amortization, at December 31, 2006, and 2005.

	December 31, 2006 (In thousands)	2005
Fort Peck lease option	$ 9,507	$ 7,971
Pipeline extension project	6,920	7,106
Unamortized loss on reacquired debt	376	1,503
Deferred rate case expenditures	2,341	842
Total regulatory assets	$ 19,144	$ 17,422

We continually assess the potential recovery of our regulatory assets based on such factors as regulatory changes and the impact of competition to determine the probability of future recovery of these assets. We believe the recovery of the existing regulatory assets is probable. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time.

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. 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. We had no allowance for doubtful accounts at December 31, 2006 and 2005. We do not own the gas that we transport, and therefore we do not assume the related natural gas commodity risk.

Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these financial statements. Our FERC tariff, through December 31, 2006, established the method of accounting for and calculating income taxes which would have been paid or accrued if we were organized during the period as a corporation. As a result, for purposes of determining Partners' capital for regulatory accounting purposes, it is reduced by the amount equivalent to the net accumulated deferred income taxes. Such amounts were approximately $365 million and $360 million at December 31, 2006, and 2005, respectively, and are primarily related to accelerated depreciation and other plant-related differences. Pursuant to the terms of the settlement of our 2005 rate case, during the time period that the rates effective January 1, 2007 are in effect, the treatment historically accorded deferred income taxes will be observed by us for regulatory accounting purposes.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

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, net of salvage and cost of removal. 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. The effective depreciation rate applied to our transmission plant was 2.25 percent for 2004, 2005, and 2006. Composite rates are applied to all other functional groups of property having similar economic characteristics. See Note 4 for changes to our depreciation rate effective January 1, 2007.

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 operators 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 use financial instruments in the management of our interest rate exposure. A control environment has been established which includes policies and procedures for risk assessment and the approval, reporting and monitoring of financial instrument activities. We do not use these instruments for trading purposes. SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and SFAS No. 138, requires that all derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheets as either an asset or liability measured at their fair value. We determine the fair value of a derivative instrument by the present value of its future cash flows based on market prices from third party sources. 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 8 for a discussion of our derivative instruments and hedging activities.

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. If operating leases include escalating rental payments, we determine the cumulative rental payments anticipated and recognize rent expense on a straight-line basis over the term of the lease.

Impairment of Long-Lived Assets

We assess our long-lived assets for impairment based on SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. 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 the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

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 in accordance with SFAS No. 5, Accounting for Contingencies. 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.

Reclassifications

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

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3. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. Effective December 31, 2005, we adopted FIN 47, Accounting for Conditional Asset Retirement Obligations an interpretation of SFAS No. 143. FIN 47 clarifies the term conditional asset retirement obligation, as used in SFAS No. 143 and the circumstances under which an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. 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.

4. RATES AND REGULATORY ISSUES

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

As required by the provisions of the settlement of our 1999 rate case, on November 1, 2005 we filed a rate case with the FERC. In December 2005, the FERC issued an order that identified issues that were raised in the proceeding and accepted the proposed rates, but suspended their effectiveness until May 1, 2006. Beginning May 1, 2006, the new rates were collected subject to refund through September 30, 2006. Based on the settlement, discussed below, we refunded $10.8 million to our customers in the fourth quarter of 2006.

On September 18, 2006, we filed a stipulation and agreement which documented the settlement reached between us and our participant customers and supported by the FERC trial staff. The uncontested settlement was approved by the FERC on November 21, 2006.

The settlement established maximum long-term mileage-based rates and charges for transportation on our system. Beginning in 2007, overall rates were reduced, compared with rates prior to the filing, by approximately 5 percent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dth is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The factors used in calculating depreciation expense for transmission plant were increased from 2.25 percent to 2.40 percent. 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.

5. TRANSPORTATION SERVICE AGREEMENTS

Operating revenues are collected pursuant to the FERC tariff through transportation service agreements. Our firm service agreements at December 31, 2006, extend for various terms with termination dates that range from December 2006 to May 2016. We also have interruptible transportation service agreements and other transportation service agreements with numerous shippers. 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.

At December 31, 2006, our largest shippers, Nexen Marketing, U.S.A. Inc. (Nexen), BP Canada Energy Marketing Corp. (BP Canada) and Cargill Inc. (Cargill) were obligated for approximately 16 percent, 16 percent and 14 percent of design capacity, respectively. The Nexen, BP Canada and Cargill firm service agreements extend for various terms with termination dates ranging from December 2006 to December 2013, December 2006 to April 2014 and February 2007 to December 2008, respectively.

For the year ended December 31, 2006, shippers providing significant operating revenues were BP Canada and Cargill with revenues of $66.7 million and $43.0 million, respectively. For the year ended December 31, 2005, shippers providing significant operating revenues were BP Canada, Nexen, EnCana Marketing (USA) Inc. (EnCana) and Cargill with revenues of $56.1 million, $38.1 million, $37.9 million and $34.1 million, respectively. For the year ended December 31, 2004, shippers providing significant operating revenues were BP Canada and EnCana with revenues of $65.6 million and $56.3 million, respectively.

At December 31, 2006, 2005 and 2004, we had contracted firm capacity held by one shipper affiliated with one of our general partners. ONEOK Energy, a subsidiary of ONEOK, holds firm service agreements representing approximately 1 percent of design capacity at December 31, 2006. The firm service agreements with ONEOK Energy extend for various terms with termination dates that range from March 2007 to November 2011. ONEOK Energy became affiliated with us on November 17, 2004 in connection with ONEOK s purchase of ONEOK Partners GP. Revenue from ONEOK Energy for 2006, 2005 and the period from the date of affiliation to December 31, 2004 was $7.0 million, $7.7 million and $1.1 million, respectively. At December 31, 2006 and 2005, we had outstanding receivables from ONEOK Energy of $0.3 million and $0.9 million, respectively.

6. CREDIT FACILITIES

We have entered into revolving credit facilities that are used for capital expenditures, acquisitions and general business purposes and for refinancing existing indebtedness. We entered into a $175 million five-year credit agreement (the 2005 Pipeline Credit Agreement) with certain financial institutions in May 2005. At our option, the interest rate on the outstanding borrowings may be the lender s base rate or the LIBOR plus a spread that is based on our long-term unsecured debt ratings. The 2005 Pipeline 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 fee on the principal commitment amount of $175 million. At December 31, 2006 and 2005, amounts outstanding under the 2005 Pipeline Credit Agreement were $20 million at an interest rate of 6.33 percent and $27 million at an interest rate of 5.11 percent, respectively. Borrowings under the 2005 Pipeline Credit Agreement are included in notes payable on the balance sheets.

Under the 2005 Pipeline Credit Agreement, we are required to comply with certain financial, operational and legal covenants. The 2005 Pipeline Credit Agreement requires the maintenance of a ratio of EBITDA to interest expense of greater than 3 to 1. It also requires the maintenance of the ratio of indebtedness to adjusted EBITDA (EBITDA adjusted for pro forma operating results of acquisitions made during the year) of no more than 4.5 to 1. Pursuant to the 2005 Pipeline Credit Agreement, if one or more acquisitions are consummated in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA is increased to 5 to 1 for two calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2005 Pipeline Credit Agreement may become due and payable immediately. At December 31, 2006, we were in compliance with our financial covenants.

7. LONG-TERM DEBT

Detailed information on long-term debt is as follows:

		December 31, 2006 (in thousands)	2005
1999 Pipeline Senior Notes	7.75%, due 2009	$ 200,000	$ 200,000
2001 Pipeline Senior Notes	7.50%, due 2021	250,000	250,000
2002 Pipeline Senior Notes	6.25%, due 2007	150,000	150,000
Unamortized debt (discount) premium		(156)	1,916
Current maturities		(150,000)	
Long-term debt		$ 449,844	$ 601,916

On December 1, 2004, we redeemed $75 million of the 6.25 percent Senior Notes due 2007 (the 2002 Pipeline Senior Notes). In connection with the redemption, we were required to pay a premium of $4.8 million, incurred a $0.4 million loss related to the unamortized debt costs and discount associated with the debt and received $2.5 million from the termination of interest rate swaps associated with the debt (see Note 8). The net loss of $2.7 million from the redemption is recorded as a loss on reacquired debt and amortized to interest expense over the remaining life of the 2002 Pipeline Senior Notes. During the years ended December 31, 2006, 2005 and 2004, we amortized approximately $1.1 million, $1.1 million and $0.1 million, respectively, to interest expense. At December 31, 2006, and 2005, the net unamortized loss on reacquired debt was $0.4 million and $1.5 million, respectively, which is recorded in regulatory assets on the balance sheets.

Aggregate required repayments of long-term debt for the next five years are $150 million in 2007 and $200 million in 2009. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2008, 2010 or 2011. We anticipate expanding the capacity of the 2005 Pipeline Credit Agreement and utilizing borrowings under this agreement as well as equity contributions from our partners to repay our senior notes due May 1, 2007.

Certain of our long-term debt arrangements contain requirements as to the maintenance of minimum partners capital and debt to capitalization ratios, leverage ratios and interest coverage ratios that restrict the incurrence of other indebtedness by us and also place certain restrictions on distributions to our partners.

The following estimated fair values of financial instruments represent the amount at which each instrument could be exchanged in a current transaction between willing parties. Based on quoted market prices for similar issues with similar terms and remaining maturities, the estimated fair value of the aggregate of the 1999 Pipeline Senior Notes, 2001 Pipeline Senior Notes and 2002 Pipeline Senior Notes was approximately $623 million and $637 million at December 31, 2006, and 2005, respectively. We presently intend to maintain the current schedule of maturities for the 1999 Pipeline Senior Notes, the 2001 Pipeline Senior Notes and the 2002 Pipeline Senior Notes, which will result in no gains or losses on their respective repayments. The fair value of the 2005 Pipeline Credit Agreement (Note 6) approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

8. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Prior to the anticipated issuance of fixed rate debt, we entered into forward starting interest rate swap agreements. The interest rate swap agreements were designated as cash flow hedges as they hedged the fluctuations in Treasury rates and spreads between the execution date of the swap agreements and the issuance of the fixed rate debt. The notional amount of the interest rate swap agreements did not exceed the expected principal amount of fixed rate debt to be issued. Upon issuance of the fixed rate debt, the swap agreements were terminated and the proceeds received or amounts paid to terminate the swap agreements were recorded in accumulated other comprehensive income and amortized to interest expense over the term of the debt.

During the years ended December 31, 2006, 2005, and 2004, respectively, we amortized approximately $1.3 million, $1.5 million, and $1.4 million related to the terminated interest rate swap agreements as a reduction to interest expense from accumulated other comprehensive income. We expect to amortize approximately $1.6 million as a reduction to interest expense in 2007.

In November 2004, we terminated our interest rate swap agreements with notional amounts of $225 million and received $7.5 million. Of the total proceeds, $2.5 million related to the redemption of $75 million of the 2002 Pipeline Senior Notes (see Note 7). The remaining $5.0 million is recorded in long-term debt with such amount amortized to interest expense over the remaining life of the interest rate swap agreements. During the years ended December 31, 2006, 2005, and 2004, we amortized approximately $2.1 million, $2.1 million and $0.2 million, respectively, as a reduction to interest expense. We expect to amortize approximately $0.7 million as a reduction of interest expense in 2007 for these agreements.

9. COMMITMENTS AND CONTINGENCIES

Operating Leases

Future minimum lease payments under non-cancelable operating leases on office space and rights-of-way are as follows (in thousands):

Year ending December 31,	**(In thousands)**
2007	$ 2,511
2008	2,511
2009	2,511
2010	2,186
2011	1,889
Thereafter	62,960
	$ 74,568

Expenses incurred related to these lease obligations for the years ended December 31, 2006, 2005 and 2004 were $0.7 million, $0.6 million, and $0.6 million, respectively.

Transition *Related Costs*

ONEOK Partners GP and TransCan entered into a transition services agreement for the transfer of the operator responsibilities effective April 1, 2007. As a part of the agreement, we will pay ONEOK Partners an amount of approximately $1.0 million per year for five years for previously agreed to obligations related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used to support our operations. In addition, we agreed to transfer certain identified assets of immaterial value to ONEOK Partners at either no cost or net book value as defined in the agreement.

Environmental Matters

We are not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

Other

On July 31, 2001, the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation (the Tribes) filed a lawsuit in Tribal Court against us to collect more than $3 million in back taxes, together with interest and penalties. The lawsuit related to a utilities tax on certain of our properties within the Fort Peck Indian Reservation. The Tribes and we, through a mediation process, reached a settlement with respect to pipeline right-of-way lease and taxation issues documented through an Option Agreement and Expanded Facilities Lease executed in August 2004. The settlement 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. Of the amount paid in 2004, $1.0 million was determined to be a settlement of previously accrued property taxes. The remainder has been recorded in regulatory assets on the balance sheets.

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.

10.   CASH DISTRIBUTION POLICY

Our 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 such distributions. Any changes to, or suspension of, our cash distribution policy requires the unanimous approval of our Management Committee. In December 2003, our Management Committee voted to (i) issue equity cash calls to our partners in the total amount of $130 million in 2004 and $90 million in 2007; (ii) fund future growth capital expenditures with 50 percent equity capital contributions from our partners; and (iii) change our cash distribution policy. Effective January 1, 2004, cash distributions are equal to 100 percent of 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. Upon closing the sale of the 20 percent partnership interest by ONEOK Partners to TC Pipelines, our Management Committee adopted certain changes to our cash distribution policy related to financial ratio targets and capital contributions. The change was to define minimum equity to total capitalization ratios to be used by the Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions.

On November 30, 2004, we issued an equity cash call to our partners in the total amount of $75 million, which was utilized to repay existing bank debt. This equity contribution will reduce the previously approved 2007 equity cash call from $90 million to $15 million.

11.   QUARTERLY FINANCIAL DATA (Unaudited)

2006	**Operating Revenue (In thousands)**	**Operating Income**	**Net Income to Partners**
First Quarter	$ 79,827	$ 47,697	$ 37,353
Second Quarter	71,441	35,996	25,406
Third Quarter	80,267	43,683	33,682
Fourth Quarter	79,365	43,762	33,404
2005			
First Quarter	$ 82,825	$ 51,035	$ 40,631
Second Quarter	69,786	38,781	28,763
Third Quarter	89,008	55,767	46,177
Fourth Quarter	80,032	47,165	36,675

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12. OTHER INCOME (EXPENSE)

Other income (expense) on the statement of income includes such items as investment income, nonoperating revenues and expenses, and nonrecurring other income and expense items. For the years ended December 31, 2006, 2005 and 2004, other income (expense) included:

	Years Ended December 31,		
	2006	2005	2004
	(In thousands)		
Other income			
Investment income	$ 1,086	$ 1,134	$ 1,111
Nonoperating revenue	627	487	329
Interconnects constructed	126	164	681
Bad debt expense adjustment		408	
Other	379	203	431
Other income	$ 2,218	$ 2,396	$ 2,552
Other expense			
Depreciation and amortization for non-regulated property	$ (604)	$ (351)	$ (351)
Reserves		(28)	(645)
Bad debt expense		(78)	(522)
Other	(18)	(75)	(541)
Other expense	$ (622)	$ (532)	$ (2,059)

13. RELATIONSHIPS WITH ENRON

In December 2001, Enron and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy Court. ONEOK Partners GP was affiliated with Enron until November 2004.

Enron North America, a wholly owned subsidiary of Enron in bankruptcy, was a party to transportation contracts, which obligated Enron North America to pay for 3.5 percent of our capacity. Enron had also guaranteed these obligations to us. In 2002, we had fully reserved for amounts invoiced to Enron North America. We filed claims in the bankruptcy proceedings and as a result of a settlement agreement between Enron North America, Enron and us, each of Enron North America and Enron agreed to allow our claim of approximately $20.6 million. In 2004, we adjusted our allowance for doubtful accounts to reflect an estimated recovery of $1.1 million for the claims. In June 2005, we sold our settled bankruptcy claims to a third party. Proceeds from the sale of the claims were $11.1 million. In the second quarter of 2005, we made an adjustment to our allowance for doubtful accounts of $0.6 million to reflect the agreements for the sale. In the third quarter of 2005, we recognized revenue of $9.4 million as a result of the sale.

Under the operating agreement with ONEOK Partners GP, termination costs related to Enron Corp. s Cash Balance Plan could have been Northern Border Pipeline s responsibility. As of December 31, 2003, we accrued $3.1 million, an amount estimated as our responsibility under our operating agreement for reimbursement of a proportionate share of termination costs for certain Enron defined benefit plans. In 2004, we were advised that no claim for reimbursement of the termination costs would be made, resulting in an adjustment in reserves during 2004 of $3.1 million for the termination costs.

14. ACCOUNTING PRONOUNCEMENTS

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157), which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. SFAS No. 157 is effective for our fiscal year beginning January 1, 2008. We are currently reviewing the applicability of SFAS No. 157 to our results of operations and financial position.

In September 2006, the SEC staff issued SAB Topic 1N, Financial Statements Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements (SAB No. 108), which addresses how to quantify the effect of an error on the financial statements. SAB No. 108 was effective for our fiscal year ended December 31, 2006. The adoption of SAB No. 108 did not have a material impact on our results of operations or financial position.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment (SFAS No. 123R), which requires companies to expense the fair value of share-based payments and includes changes related to the expense calculation for share-based payments. ONEOK Partners GP adopted SFAS No. 123R as of January 1, 2006, and charges us for our proportionate share of the expense recorded by ONEOK Partners GP. The adoption of SFAS No. 123R by ONEOK Partners GP did not have a material impact on our results of operations or financial position.

15. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $44.4 million was declared and paid on February 1, 2007 for the fourth quarter of 2006.

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Report of Independent Registered Public Accounting Firm on Schedule

Northern Border Pipeline Company:

We have audited in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States), the financial statements of Northern Border Pipeline Company as of December 31, 2006 and 2005 and for each of the years in the three-year period ended December 31, 2005 included in this Form 10-K, and have issued our report thereon dated February 27, 2007.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule of Northern Border Pipeline Company listed in Item 15 of Part IV of this Form 10-K is the responsibility of the Company s management and is presented for purposes of complying with the Securities and Exchange Commission s rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states, in all material respects, the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

/s/ KPMG LLP

Omaha, Nebraska
February 27, 2007

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NORTHERN BORDER PIPELINE COMPANY

SCHEDULEII VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Charged to Other Accounts (In thousands)	Deductions for Purpose for which Reserves were Created	Balance at End of Year
Reserve for regulatory issues:					
2006	$ 630	$	$ 10,787	$ 10,787	$ 630
2005	$ 1,955	$ 25	$	$ 1,350	$ 630
2004	$ 6,315	$ 640	$	$ 5,000	$ 1,955
Allowance for doubtful accounts:					
2006	$	$	$	$	$
2005	$ 4,208	$ 171	$	$ 4,379	$
2004	$ 4,815	$ 523	$	$ 1,130	$ 4,208

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