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

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2009

or

[ ] 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	52-2135448
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
13710 FNB Parkway Omaha, Nebraska	68154-5200
(Address of principal executive offices)	(Zip code)

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

Indicate by check mark if 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 [ ]

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer [X] Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company) Smaller reporting company [ ]

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

As of August 4, 2009, there were 41,227,766 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.

Glossary

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

Acquisition	The acquisition of 100 per cent of North Baja Pipeline, LLC by the Partnership
Collar Agreement	Northern Border's interest rate collar agreement
EPA	United States Environmental Protection Agency
Exchange Agreement	Agreement with the general partner pursuant to which the Partnership issued new common units to the general partner and provided for revised incentive distribution rights in exchange for the cancellation of the incentive distribution rights available to the general partner under the Amended and Restated Agreement of Limited Partnership of the Partnership
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
General partner	TC PipeLines GP, Inc.
GLGT	Great Lakes Gas Transmission Limited Partnership
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest Corporation
IDRs	Incentive Distribution Rights
LIBOR	London Interbank Offered Rate
MMcf/d	Million cubic feet per day
NBPC	Northern Border Pipeline Company
Net WCSB Flows to Markets	Net of the supply of and demand for WCSB natural gas that is available for transportation to downstream markets; where supply represents WCSB production adjusted for injections into and withdrawals from WCSB storage
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
NOV	Notice of Violation
Offering	The sale of 2,609,680 newly issued, unregistered common units representing limited partner interests in the Partnership to TransCan Northern at a price per common unit of $30.042 for an aggregate amount of approximately $78.4 million
Old IDRs	Incentive Distribution Rights per the Amended and Restated Agreement of Limited Partnership
Our pipeline systems	Great Lakes, Northern Border and Tuscarora (and North Baja beginning on July 1, 2009)
Partnership	TC PipeLines, LP and its subsidiaries
PipeLP	TC PipeLines, LP and its subsidiaries
Purchase Agreement	Common Unit Purchase Agreement
Revised IDRs	Incentive Distribution Rights per the Second Amended and Restated Agreement of Limited Partnership
REX East	Eastern segment of the Rockies Express Pipeline
REX West	Western segment of the Rockies Express Pipeline
Senior Credit Facility	TC PipeLines' revolving credit and term loan agreement
SFAS	Statement of Financial Accounting Standards
TC PipeLines	TC PipeLines, LP and its subsidiaries
TGTC	Tuscarora Gas Transmission Company
TransCan Northern	TransCan Northern Ltd.
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

TC PipeLines, LP
Consolidated Statement of Income

(unaudited) *(millions of dollars except per common unit amounts)*	Three months ended June 30, **2009**	2008	Six months ended June 30, **2009**	2008
Equity income from investment in Great Lakes (Note 2)	**12.9**	13.8	**32.4**	32.4
Equity income from investment in Northern Border (Note 3)	**5.4**	8.7	**21.0**	28.2
Transmission revenues	**8.2**	8.2	**16.6**	15.1
Operating expenses	**(4.1)**	(2.3)	**(6.7)**	(4.5)
Depreciation	**(1.7)**	(1.7)	**(3.5)**	(3.3)
Financial charges, net and other	**(7.0)**	(7.5)	**(14.3)**	(15.1)
Net income	**13.7**	19.2	**45.5**	52.8
Net income allocation				
Common units	**10.8**	16.2	**39.3**	46.6
General partner	**2.9**	3.0	**6.2**	6.2
	13.7	19.2	**45.5**	52.8
Net income per common unit (Note 6)	**$ 0.31**	$ 0.47	**$ 1.13**	$ 1.34
Weighted average common units outstanding *(millions)*	**34.9**	34.9	**34.9**	34.9
Common units outstanding, end of the period *(millions)*	**34.9**	34.9	**34.9**	34.9

Consolidated Statement of Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended June 30, **2009**	2008	Six months ended June 30, **2009**	2008
Net income	**13.7**	19.2	**45.5**	52.8
Other comprehensive income/(loss)				
Change associated with hedging transactions (Note 9)	**5.0**	11.9	**6.4**	(0.4)
Change associated with hedging transactions of investees	**0.3**	1.9	**0.2**	0.3
	5.3	13.8	**6.6**	(0.1)
Total comprehensive income	**19.0**	33.0	**52.1**	52.7

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

TC PipeLines, LP
Consolidated Balance Sheet

(unaudited)

(millions of dollars)	**June 30, 2009**	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	**22.8**	8.4
Accounts receivable and other	**2.9**	3.4
	25.7	11.8
Investment in Great Lakes (Note 2)	**702.7**	704.5
Investment in Northern Border (Note 3)	**493.6**	514.8
Plant, property and equipment (net of $72.1 accumulated depreciation, 2008 - $68.6)	**131.0**	134.2
Goodwill	**81.7**	81.7
Other assets	**1.2**	1.5
	1,435.9	1,448.5
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable	**2.2**	2.2
Accrued interest	**1.4**	2.1
Current portion of long-term debt (Note 5)	**4.4**	4.4
Current portion of fair value of derivative contracts (Note 9)	**10.8**	11.8
	18.8	20.5
Fair value of derivative contracts and other (Note 9)	**14.8**	20.0
Long-term debt (Note 5)	**530.1**	532.4
	563.7	572.9
Partners' Equity		
Common units	**881.6**	891.4
General partner	**18.9**	19.1
Accumulated other comprehensive loss	**(28.3)**	(34.9)
	872.2	875.6
	1,435.9	1,448.5

Subsequent events (Note 12)

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

TC PipeLines, LP
Consolidated Statement of Cash Flows

(unaudited) *(millions of dollars)*	**Six months ended June 30, 2009**	2008
CASH GENERATED FROM OPERATIONS		
Net income	**45.5**	52.8
Depreciation	**3.5**	3.3
Amortization of other assets	**0.3**	0.2
Increase in long-term liabilities	**0.2**	0.1
Equity allowance for funds used during construction	**-**	(0.2)
Increase in operating working capital (Note 10)	**(0.2)**	(1.9)
	49.3	54.3
INVESTING ACTIVITIES		
Cumulative distributions in excess of equity earnings:		
Great Lakes	**1.8**	3.3
Northern Border	**25.7**	21.2
Investment in Northern Border (Note 3)	**(4.3)**	-
Capital expenditures	**(0.3)**	(5.4)
Increase in investing working capital (Note 10)	**-**	(2.5)
	22.9	16.6
FINANCING ACTIVITIES		
Distributions paid (Note 7)	**(55.5)**	(53.0)
Long-term debt repaid (Note 5)	**(2.3)**	(24.3)
	(57.8)	(77.3)
Increase/(decrease) in cash and cash equivalents	**14.4**	(6.4)
Cash and cash equivalents, beginning of period	**8.4**	7.5
Cash and cash equivalents, end of period	**22.8**	1.1
Interest payments made	**7.7**	14.3

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

TC PipeLines, LP
Consolidated Statement of Changes in Partners' Equity

(unaudited)	**Common Units**		**General Partner**	**Accumulated Other Comprehensive (Loss)/Income [1]**	**Partners' Equity**	
	(millions of units)	*(millions of dollars)*	*(millions of dollars)*	*(millions of dollars)*	*(millions of units)*	*(millions of dollars)*
Partners' equity at December 31, 2008	34.9	891.4	19.1	(34.9)	34.9	875.6
Net income	-	39.3	6.2	-	-	45.5
Distributions paid	-	(49.1)	(6.4)	-	-	(55.5)
Other comprehensive income	-	-	-	6.6	-	6.6
Partners' equity at June 30, 2009	**34.9**	**881.6**	**18.9**	**(28.3)**	**34.9**	**872.2**

[1] TC PipeLines, LP uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at June 30, 2009, the amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in the next 12 months is $10.8 million, which will be offset by a reduction to interest expense of a similar amount.

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

Note 1 Organization and Significant Accounting Policies

TC PipeLines, LP and its subsidiaries are collectively referred to herein as "TC PipeLines" or "the Partnership". In this report, references to "we", "us" or "our" refer to TC PipeLines or the Partnership.

The preparation of financial statements in conformity with United States of America (U.S.) generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as 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. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and include all adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the financial results for the interim periods presented.

The results of operations for the three and six months ended June 30, 2009 and 2008 are not necessarily indicative of the results that may be expected for a full fiscal year. The unaudited interim financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2008. Our significant accounting policies are consistent with those disclosed in Note 2 of the financial statements in our Annual Report on Form 10-K for the year ended December 31, 2008. Certain comparative figures have been reclassified to conform to the current period's presentation.

Note 2 Investment in Great Lakes

We own a 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). Great Lakes is regulated by the Federal Energy Regulatory Commission (FERC) and is operated by a wholly-owned subsidiary of TransCanada Corporation. TransCanada Corporation and its subsidiaries are herein collectively referred to as "TransCanada".

We use the equity method of accounting for our interest in Great Lakes. Great Lakes had no undistributed earnings for the six months ended June 30, 2009 and 2008.

The following tables contain summarized financial information of Great Lakes:

Summarized Consolidated Great Lakes Income Statement *(unaudited)*	**Three months ended June 30,**		**Six months ended June 30,**	
(millions of dollars)	**2009**	2008	**2009**	2008
Transmission revenues	**69.0**	67.5	**151.5**	147.2
Operating expenses	**(17.1)**	(13.7)	**(33.1)**	(28.8)
Depreciation	**(14.6)**	(14.6)	**(29.2)**	(29.2)
Financial charges, net and other	**(8.1)**	(8.2)	**(16.3)**	(16.4)
Michigan business tax	**(1.3)**	(1.3)	**(3.1)**	(3.0)
Net income	**27.9**	29.7	**69.8**	69.8

Summarized Consolidated Great Lakes Balance Sheet

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Assets		
Cash and cash equivalents	**-**	1.6
Other current assets	**91.0**	80.2
Plant, property and equipment, net	**895.7**	923.4
	986.7	1,005.2
Liabilities and Partners' Equity		
Current liabilities	**36.8**	43.0
Deferred credits	**3.0**	2.3
Long-term debt, including current maturities	**421.0**	430.0
Partners' capital	**525.9**	529.9
	986.7	1,005.2

Note 3 Investment in Northern Border

We own a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border). Northern Border is regulated by FERC and is operated by TransCanada.

We use the equity method of accounting for our interest in Northern Border. Northern Border had no undistributed earnings for the six months ended June 30, 2009 and 2008.

The following tables contain summarized financial information of Northern Border:

Summarized Northern Border Income Statement *(unaudited)*	**Three months ended June 30,**		**Six months ended June 30,**	
(millions of dollars)	**2009**	2008	**2009**	2008
Transmission revenues	**54.2**	61.3	**128.7**	145.1
Operating expenses	**(18.3)**	(18.8)	**(36.8)**	(38.2)
Depreciation	**(15.5)**	(15.3)	**(30.8)**	(30.5)
Financial charges, net and other	**(9.2)**	(9.5)	**(18.3)**	(19.2)
Net income	**11.2**	17.7	**42.8**	57.2

Summarized Northern Border Balance Sheet

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Assets		
Cash and cash equivalents	**13.1**	21.6
Other current assets	**26.3**	39.1
Plant, property and equipment, net	**1,368.7**	1,390.8
Other assets	**24.5**	24.5
	1,432.6	1,476.0
Liabilities and Partners' Equity		
Current liabilities	**41.4**	48.7
Deferred credits and other	**7.8**	11.2
Long-term debt, including current maturities	**639.5**	630.4
Partners' equity		
Partners' capital	**749.2**	791.4
Accumulated other comprehensive loss	**(5.3)**	(5.7)
	1,432.6	1,476.0

Note 4 Investment in Tuscarora

The Partnership wholly-owns Tuscarora Gas Transmission Company (Tuscarora). Tuscarora is regulated by FERC and operated by TransCanada.

We use the consolidation method of accounting for our investment in Tuscarora.

The following tables contain summarized financial information of Tuscarora:

Summarized Tuscarora Income Statement *(unaudited)* *(millions of dollars)*	**Three months ended June 30, 2009**	Three months ended June 30, 2008	**Six months ended June 30, 2009**	Six months ended June 30, 2008
Transmission revenues	**8.2**	8.2	**16.6**	15.1
Operating expenses	**(1.2)**	(1.1)	**(2.6)**	(2.3)
Depreciation	**(1.7)**	(1.7)	**(3.5)**	(3.3)
Financial charges, net and other	**(1.2)**	(1.1)	**(2.3)**	(2.0)
Net income	**4.1**	4.3	**8.2**	7.5

Summarized Tuscarora Balance Sheet

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Assets		
Other current assets	**7.6**	3.1
Plant, property and equipment, net	**131.0**	134.2
Other assets	**0.2**	0.3
	138.8	137.6
Liabilities and Partners' Equity		
Current liabilities	**2.1**	2.0
Long-term debt, including current maturities	**59.5**	61.8
Partners' capital	**77.2**	73.8
	138.8	137.6

Summarized Tuscarora Cash Flow Statement *(unaudited)* *(millions of dollars)*	**Three months ended June 30, 2009**	Three months ended June 30, 2008	**Six months ended June 30, 2009**	Six months ended June 30, 2008
Cash flows provided by operating activities	**4.8**	4.1	**12.0**	10.1
Cash flows used in investing activities	**(0.1)**	(3.9)	**(0.3)**	(7.9)
Cash flows used in financing activities	**(4.7)**	(0.2)	**(11.7)**	(8.3)
Decrease in cash and cash equivalents	-	-	-	(6.1)
Cash and cash equivalents, beginning of period	-	-	-	6.1
Cash and and cash equivalents, end of period	-	-	-	-

Note 5 Credit Facility and Long-Term Debt

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Senior Credit Facility	**475.0**	475.0
7.13% Series A Senior Notes due 2010	**49.7**	51.3
7.99% Series B Senior Notes due 2010	**4.7**	5.0
6.89% Series C Senior Notes due 2012	**5.1**	5.5
	534.5	536.8

TC PipeLines' revolving credit and term loan agreement (Senior Credit Facility) consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility. At June 30, 2009, no draws were made on our senior revolving credit facility; however, a $170.0 million draw was made subsequently to partially fund the North Baja acquisition. See Note 12 for further details.

The interest rate on the Senior Credit Facility averaged 1.65 per cent for the three months ended June 30, 2009 (2008 - 3.44 per cent), while for the six months ended June 30, 2009 the interest rate on the Senior Credit Facility averaged 2.04 per cent (2008 - 4.24 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.76 per cent for the three months ended June 30, 2009 (2008 - 5.02 per cent) and 4.91 per cent for the six months ended June 30, 2009 (2008 - 5.15 per cent). Prior to hedging activities, the interest rate was 1.19 per cent at June 30, 2009 (December 31, 2008 - 2.67 per cent). At June 30, 2009, we were in compliance with our financial covenants.

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

(unaudited) *(millions of dollars)*	
2009	2.2
2010	53.4
2011	475.8
2012	3.1
	534.5

Note 6 Net Income per Common Unit

Net income per common unit is computed by dividing net income, after deduction of the general partner's allocation, by the weighted average number of common units outstanding. The general partner's allocation is equal to an amount based upon the general partner's two per cent interest, plus an amount equal to incentive distributions. Incentive distributions are received by the general partner if quarterly cash distributions on the common units exceed levels specified in the partnership agreement. Net income per common unit was determined as follows:

(unaudited)	**Three months ended June 30,**		**Six months ended June 30,**	
(millions of dollars except per unit)	**2009**	2008	**2009**	2008
Net income	**13.7**	19.2	**45.5**	52.8
Net income allocated to general partner				
General partner interest	**(0.3)**	(0.4)	**(0.9)**	(1.1)
Incentive distribution income allocation	**(2.6)**	(2.6)	**(5.3)**	(5.1)
	(2.9)	(3.0)	**(6.2)**	(6.2)
Net income allocable to common units	**10.8**	16.2	**39.3**	46.6
Weighted average common units outstanding *(millions)*	**34.9**	34.9	**34.9**	34.9
Net income per common unit	**$ 0.31**	$ 0.47	**$ 1.13**	$ 1.34

Effective January 1, 2009, the Partnership adopted the provisions of EITF 07-4 "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per share*, to Master Limited Partnerships".

According to the new standard, for purposes of calculating net income per common unit, net income must be reduced by the amount of available cash that will be distributed with respect to that period. Any undistributed income must be allocated to the various interest holders based on the contractual provisions of the partnership agreement. Under the partnership agreement, for any quarterly period, the participation of the incentive distribution rights (IDRs) is limited to available cash distributions declared. Accordingly, the undistributed net income has been allocated to the general partner's two per cent interest and the common unitholders.

The retrospective application of EITF 07-4 impacted the amount of net income allocated to the IDR holder in the six months ended June 30, 2008, as the amount previously allocated to the IDR holder was based on the cash distribution paid in that period and will now be based on the amount declared for the period. This did not impact the net income per common unit for the second quarter of 2008, but resulted in a reduction from $1.36 to $1.34 in net income per common unit for the six months ended June 30, 2008.

Note 7 Cash Distributions

For the three and six months ended June 30, 2009, we distributed $0.705 and $1.41 per common unit (2008 - $0.70 and $1.365 per common unit). The distributions for the three and six months ended June 30, 2009 included incentive distributions to the general partner of $2.7 million and $5.3 million (2008 - $2.5 million and $4.4 million).

Note 8 Related Party Transactions

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $0.5 million and $0.9 million for the three and six months ended June 30, 2009 (2008 - $0.6 million and $1.1 million).

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

Total costs charged to our pipeline systems during the three and six months ended June 30, 2009 and 2008 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at June 30, 2009 and December 31, 2008 are summarized in the following tables:

(unaudited) *(millions of dollars)*	**Three months ended June 30, 2009**	2008	**Six months ended June 30, 2009**	2008
Costs charged by TransCanada and its affiliates:				
Great Lakes	**8.2**	7.9	**15.5**	15.2
Northern Border	**6.4**	9.2	**12.7**	16.0
Tuscarora	**0.8**	0.9	**1.5**	2.0
Impact on the Partnership's net income:				
Great Lakes	**3.7**	3.1	**6.9**	6.5
Northern Border	**3.1**	3.1	**6.0**	6.4
Tuscarora	**0.7**	0.9	**1.4**	2.0

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Amount owed to TransCanada and its affiliates:		
Great Lakes	**3.8**	4.5
Northern Border	**2.7**	2.8
Tuscarora	**0.7**	0.8

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed price contracts with remaining terms ranging from one to nine years. Great Lakes earned $35.1 million of transportation revenues under these contracts for the three months ended June 30, 2009 (2008 - $37.9 million). This amount represents 50.9 per cent of total revenues earned by Great Lakes for the three months ended June 30, 2009 (2008 - 56.1 per cent). $16.3 million of affiliated revenue is included in our equity income from Great Lakes for the three months ended June 30, 2009 (2008 - $17.6 million).

Great Lakes earned $72.4 million of transportation revenues from TransCanada and its affiliates for the six months ended June 30, 2009 (2008 - $68.2 million). This amount represents 47.8 per cent of total revenues earned by Great Lakes for the six months ended June 30, 2009 (2008 - 46.3 per cent). $33.6 million of this transportation revenue is included in our equity income from Great Lakes for the six months ended June 30, 2009 (2008 - $31.7 million).

At June 30, 2009, $12.1 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2008 - $12.5 million).

Note 9 Derivative Financial Instruments

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged at June 30, 2009 was $375.0 million (December 31, 2008 - $475.0 million). At June 30, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $25.3 million (December 31, 2008 - negative $31.7 million). Under Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS 157), financial instruments are recorded at fair value on a recurring basis. We have classified all our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. During the three and six months ended June 30, 2009, we recorded interest expense of $3.7 million and $6.9 million in regards to the interest rate swaps and options. In 2008, we recorded interest expense of $2.0 million and $2.3 million for the three and six months ended June 30 in regards to the interest rate swaps and options. These expenses are included in the line item "Financial charges, net and other" on the Partnership's consolidated statement of income.

Note 10 Changes in Working Capital

(unaudited)	**Six months ended June 30,**	
(millions of dollars)	**2009**	2008
Decrease in accounts receivable and other	**0.5**	0.6
Decrease in bank indebtedness	-	(1.4)
Decrease in accounts payable	-	(2.8)
Decrease in accrued interest	**(0.7)**	(0.8)
	(0.2)	(4.4)
Increase in investing working capital	-	(2.5)
Increase in operating working capital	**(0.2)**	(1.9)

Note 11 Accounting Pronouncements

The Partnership adopted the provision of SFAS No. 157-2, *Effective Date of FASB Statement No. 157* (SFAS 157-2), for all non-financial assets and liabilities measured on a recurring basis, effective January 1, 2009. The adoption of SFAS 157-2 has had no material impact on our results of operations or financial position.

The Emerging Issues Task Force of the Financial Accounting Standards Board (FASB) issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per share*, to Master Limited Partnerships," which was ratified by the FASB in March 2008. EITF 07-4 is effective for fiscal years beginning after December 15, 2008. The Partnership adopted the provisions of EITF 07-4 effective January 1, 2009. Refer to Note 6 for the impact to our financial statements.

The Partnership adopted the provisions of SFAS No. 161, *Disclosures about Derivatives Instruments and Hedging activities-an amendment of FASB Statement No. 133*, effective January 1, 2009. There was no material effect on the Partnerships' disclosure following adoption of this standard.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS 165), which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS 165 is effective for the Partnership's interim reporting at June 30, 2009. SFAS 165 did not have a material impact on the Partnership's disclosures.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification ™ and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168), as a replacement of SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS 168 will become the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. SFAS 168 is effective for the Partnership's interim reporting period ending after September 15, 2009. The adoption of this standard will have no impact on disclosures or amounts recorded in the Partnership's financial statements.

Note 12 Subsequent Events

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja Pipeline, LLC (North Baja) from Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, for an initial total purchase price of $271.3 million, subject to certain closing adjustments. The acquisition was financed through a combination of (i) a draw of $170.0 million on the Partnership's $250.0 million revolving portion of its Senior Credit Facility, which previously had no outstanding borrowings, (ii) issuance of 2,609,680 common units at $30.042 per common unit to TransCan Northern Ltd., a wholly-owned subsidiary of TransCanada, for gross proceeds of $78.4 million, (iii) issuance of additional general partner interest to the general partner of $1.6 million, which is required to maintain the general partner's two per cent general partner interest in the Partnership, and (iv) approximately $21.3 million in cash on hand.

If GTN completes an expansion of the pipeline from the Mexico/Arizona border to Yuma City, Arizona by June 30, 2010, the Partnership will pay GTN up to an additional $10.0 million for the expansion, which amount shall be determined using a formula that is based on transportation service agreements to be entered into in connection with the expansion.

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

The Revised IDRs reset the IDRs to two per cent, down from the distribution levels of the Old IDRs at 50 per cent. The distribution levels of the Revised IDRs increase to 15 per cent and 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit or $3.24 and $3.52 per common unit on an annualized basis, respectively.

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

On July 21, 2009, the Board of Directors of the general partner declared the Partnership's second quarter 2009 cash distribution in the amount of $0.73 per common unit, payable on August 14, 2009, to unitholders of record on July 31, 2009.

The Partnership has evaluated subsequent events from July 1, 2009 through August 4, 2009, which represents the date the financial statements were issued.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discusses the results of operations and liquidity and capital resources of TC PipeLines, LP, along with those of Great Lakes Gas Transmission Limited Partnership (Great Lakes), Northern Border Pipeline Company (Northern Border) and Tuscarora Gas Transmission Company (Tuscarora), as a result of the Partnership's ownership interests.

As the acquisition of North Baja Pipeline, LLC (North Baja) occurred subsequent to June 30, 2009, the following does not include a discussion of the financial condition and results of operations of North Baja.

FORWARD-LOOKING STATEMENTS

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

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

- the ability of Great Lakes and Northern Border to continue to make distributions at their current levels;
- the impact of unsold capacity on Great Lakes and Northern Border being greater or less than expected;
- competitive conditions in our industry and the ability of Great Lakes, Northern Border, Tuscarora and North Baja, (together "our pipeline systems"), to market pipeline capacity on favorable terms, which is affected by:
  - future demand for and prices of natural gas;
  - level of natural gas basis differentials;
  - competitive conditions in the overall natural gas and electricity markets;
  - availability of supplies of Canadian and United States (U.S.) natural gas, including newly discovered natural gas developments such as the Horn River and Montney shale gas developments in Western Canada, U.S. Rockies and U.S. Mid-Continent shale gas developments, and the Marcellus shale gas developments;
  - availability of additional storage capacity and current storage levels;
  - level of liquefied natural gas imports;
  - weather conditions that impact supply and demand;
  - ability of shippers to meet credit worthiness requirements; and
  - competitive developments by Canadian and U.S. natural gas transmission companies;
- changes in relative cost structures of natural gas producing basins, such as changes in royalty programs, that may prejudice the development of the Western Canada Sedimentary Basin (WCSB);
- the decision by other pipeline companies to advance projects which will affect our pipeline systems and the regulatory, financing and construction risks related to construction of interstate natural gas pipelines;
- performance of contractual obligations by customers of our pipeline systems;
- the imposition of entity level taxation by states on partnerships;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the impact of current and future laws, rulings and governmental regulations, particularly Federal Energy Regulatory Commission (FERC) regulations, and proposed and pending legislation by Congress and proposed and pending regulations by the U.S. Environmental Protection Agency (EPA) related to greenhouse gas emissions on us and our pipeline systems;
- our ability to control operating costs and the ability of TransCanada to implement its reorganization of U.S. pipeline operations, including the operations of our pipeline systems, and realize expected cost savings; and
- the severity and length of the current economic downturn, which impacts:
  - the debt and equity capital markets and our ability to access these markets;
  - the overall demand for natural gas by end users; and
  - natural gas prices

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. Please also read Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2008. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. These forward-looking statements and information are made only as of the date of the filing of this report, and except as required by applicable law, we undertake no obligation to update these forward-looking statements and information to reflect new information, subsequent events or otherwise.

The following discussion and analysis should be read in conjunction with our 2008 Annual Report on Form 10-K and the unaudited financial statements and notes thereto included in Item 1. "Financial Statements" of this Quarterly Report on Form 10-Q. All amounts are stated in U.S. dollars.

PARTNERSHIP OVERVIEW

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

TC PipeLines, LP and its subsidiaries are collectively referred to herein as "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., a wholly-owned subsidiary of TransCanada. TransCanada and its subsidiaries are herein collectively referred to as "TransCanada".

We own a 46.45 per cent general partner interest in Great Lakes. The other 53.55 per cent partner interest in Great Lakes is held by TransCanada.

We own a 50 per cent general partner interest in Northern Border, while the other 50 per cent general partner interest is held by ONEOK Partners, L.P., a publicly traded limited partnership that is controlled by ONEOK, Inc.

We own 100 per cent of Tuscarora.

We own 100 per cent of North Baja, which we acquired on July 1, 2009 from TransCanada. Please read Recent Developments within this section for additional information regarding the acquisition.

Our general partner interests in Great Lakes, Northern Border, Tuscarora and North Baja represent our only material assets at July 1, 2009. As a result, we are dependent upon our pipeline systems for all of our available cash. Our pipeline systems derive their operating revenue from transportation of natural gas.

Great Lakes Overview

Great Lakes is a Delaware limited partnership formed in 1990. 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 Canadian border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

Northern Border Overview

Northern Border is a Texas general partnership formed in 1978. Northern Border transports natural gas from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota, and in the Powder River Basin of Wyoming and Montana, as well as synthetic gas produced at the Dakota Gasification plant in North Dakota.

Tuscarora Overview

Tuscarora is a Nevada general partnership formed in 1993. Tuscarora originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs southeast through Northeastern California and Northwestern Nevada. Tuscarora's pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada.

North Baja Overview

The Partnership acquired 100 per cent of North Baja from TransCanada on July 1, 2009. North Baja is a Delaware limited liability company formed in 2000. The North Baja system extends from an interconnection with El Paso Natural Gas Company near Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border where it connects with the Gasoducto Bajanorte natural gas pipeline system which is owned by Sempra Energy International.

The pipeline system was initially placed in service in 2002 and was constructed to service demand from new electricity generators in Baja California, Mexico. In 2008, an expansion was completed to allow the pipeline to receive gas sourced from Sempra Energy International's Energia Costa Azul LNG terminal off the coast of Baja California, Mexico and flow this gas north into markets in Southern California and Arizona.

North Baja consists of an 80-mile pipeline with 30 and 36-inch diameter pipe and a physical capacity of up to 600 million cubic feet per day (MMcf/d). There is one compressor station with a total of 21,600 horsepower, and measurement facilities at two receipt points and three delivery points.

North Baja's transportation contracts are with electricity generators in Baja California, Mexico and owners of the Costa Azul LNG facility, which generated $32.9 million of transmission revenues and $16.2 million in net income in 2008. Due to North Baja's bi-directional capability, its contracted capacity is in excess of its physical capacity. At June 30, 2009, North Baja had firm transportation contracts for approximately 133 per cent of its physical capacity. Substantially all of these contracts expire between 2022 and 2028. The weighted average remaining life of these contracts at June 30, 2009 was 16.6 years with over 87 per cent of the volumes contracted under negotiated rates.

North Baja currently receives gas for transportation from its interconnection with El Paso Natural Gas Company near Ehrenberg, Arizona. The average throughput on the North Baja system was 283 MMcf/d in 2008. There was no throughput in 2008 sourced from the Costa Azul LNG facility.

Due to the long-term nature of North Baja's transportation contracts and the fact that its capacity is fully contracted, changes in the supply of and demand for natural gas have limited impact on North Baja's results.

North Baja is operated by TransCanada.

RECENT DEVELOPMENTS

North Baja Acquisition and IDR Restructuring

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja from GTN, a wholly-owned subsidiary of TransCanada, for an initial total purchase price of $271.3 million, subject to certain closing adjustments. The acquisition was financed through a combination of (i) a draw of $170.0 million on the Partnership's $250.0 million revolving portion of its Senior Credit Facility, which previously had no outstanding borrowings, (ii) issuance of 2,609,680 common units at $30.042 per common unit to TransCan Northern Ltd., an wholly-owned subsidiary of TransCanada, for gross proceeds of $78.4 million, (iii) issuance of additional general partner interest to the general partner of $1.6 million, which is required to maintain the general partner's two per cent general partner interest in the Partnership, and (iv) approximately $21.3 million in cash on hand.

If GTN completes an expansion of the pipeline from the Mexico/Arizona border to Yuma City, Arizona by June 30, 2010, the Partnership will pay GTN up to an additional $10.0 million for the expansion, which amount shall be determined using a formula that is based on transportation service agreements to be entered into in connection with the expansion.

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

The Revised IDRs reset the IDRs to two per cent, down from the distribution levels of the Old IDRs at 50 per cent. The distribution levels of the Revised IDRs increase to 15 per cent and 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit or $3.24 and $3.52 per common unit on an annualized basis, respectively.

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

FACTORS THAT IMPACT OUR BUSINESS

Key factors that impact our business are the cash flows received from our investments and our ability to maintain a strong and balanced financial position. Cash flows from our investments are dependent upon the ability of Great Lakes and Northern Border to make distributions to us and of Tuscarora and North Baja to generate positive operating cash flows. Partnership cash flows from our investments are necessary to fund distributions to our unitholders. A strong financial position will ensure that we are able to maintain a prudent level of available cash to make distributions to our unitholders.

FACTORS THAT IMPACT THE BUSINESS OF OUR PIPELINE SYSTEMS

Our pipeline systems provide natural gas transportation services to their customers. Key factors that impact their business are the supply of and demand for natural gas in the markets in which our pipeline systems operate; the customers of our pipeline systems and the mix of services they require; competition; and government regulation of natural gas pipelines. These factors are discussed in more detail below.

Supply and Demand of Natural Gas

Our pipeline systems, excluding North Baja, depend upon the continued availability of natural gas production and reserves in the regions we access, primarily the WCSB. Our pipeline systems provide their customers with natural gas transportation services to market demand areas. The Net WCSB Flows to Markets are dependent upon natural gas production levels, demand for natural gas in Western Canada, and storage capacity for Western Canadian natural gas and demand for storage injection. The Net WCSB Flows to Markets were approximately one billion cubic feet per day lower in the second quarter of 2009 compared to the same period in 2008, due mainly to a decrease in production combined with a reduction in net withdrawals from Western Canadian storage. Low commodity prices for natural gas have resulted in reductions in exploration and development activity for natural gas in the WCSB. As well, with these low prices and reduced market demand, producers are reluctant to withdraw natural gas from storage. U.S. natural gas production, a supply competitor to the WCSB, continues to be strong, mainly due to the development of unconventional reserves in the lower 48 states.

Decreases in WCSB production are expected to continue throughout the remainder of 2009 due to a decline in drilling and exploration activity by WCSB producers, mainly related to the low commodity price environment. Decreases in U.S. natural gas production are also expected in the remainder of the year as a result of lower commodity prices and the related reduction in exploration and development activity. Natural gas prices are expected to continue to be under pressure during the remainder of 2009 due to declining oil prices, declining natural gas demand, current levels of gas in storage and the general economic slowdown.

Factors which may mitigate declines related to WCSB production in the future include strengthening gas prices and decreases in oil prices as they affect demand from Alberta oil sands production. Over the long-term, we expect WCSB producers will continue to explore and develop new fields in Western Canada as well as direct significant activity at unconventional resources such as coal bed methane and shale gas. Additional Canadian natural gas supply sources may be available in the future if new pipeline projects associated with the Montney and Horn River shale gas regions in Western Canada, the Mackenzie Delta in Northern Canada and the North Slope of Alaska are constructed.

Factors which may impact the overall demand for natural gas include weather conditions, economic conditions, government regulation, availability and price of alternative energy sources, fuel conservation measures, and technological advances in fuel economy and energy generation devices. Although demand for natural gas is expected to continue to decline in North America in 2009 with the current economic downturn, we expect a demand increase in the long term. In certain sectors, such as the electric generation sector, lower natural gas prices should lead to an increase in demand for natural gas.

Western Canadian natural gas in storage is currently at a five year high. U.S. working gas storage levels are also at near record high levels. High levels of injection into Western Canadian gas storage result in less WCSB gas available for export while high U.S. gas storage levels impact the demand for natural gas in the market areas that storage serves. High overall storage levels have a dampening effect on natural gas prices which in turn impacts ongoing production. High Western Canadian gas storage levels may impact WCSB gas available for export over the short term as producers may be forced to either transport or shut in production beyond the capacity of the storage facilities.

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

Net WCSB Flows to Markets is one of the factors which impacts the throughput on our Great Lakes and Northern Border pipeline systems. The other important factor impacting throughput is the activity in the natural gas markets served by our pipeline systems. We cannot predict the impact of any continued declines in Net WCSB Flows to Markets and uncertain market conditions are expected to continue to affect throughput for the remainder of 2009.

Throughput on the Great Lakes pipeline system in the second quarter of 2009 (average 2,053 MMcf/d) was slightly lower compared to the same period in 2008 (average 2,071 MMcf/d). Increases in short term and discretionary volumes were more than offset by the underutilization of firm contracts. Decreases in throughput related to underutilization of firm contracts have a minimal impact on revenue.

Throughput on Northern Border declined in the second quarter of 2009 (average 1,499 MMcf/d) relative to the same period in 2008 (average 1,620 MMcf/d) as the Midwest markets served by Northern Border continued to be impacted by the incremental supply from the Rockies natural gas basins transported to these markets on the western segment of the Rockies Express Pipeline (REX West). Decreased overall demand also reduces the ability to contract available pipeline capacity serving this market area.

Tuscarora transports natural gas supply from the WCSB; however, the transportation capacity on our Tuscarora pipeline system is substantially contracted under long term firm contracts. All of North Baja's physical capacity has been contracted under long-term firm contracts and North Baja transports gas sourced either from the Costa Azul LNG facility or from El Paso Natural Gas Company which is primarily gas originating from the Texas supply region. Therefore, although throughput may vary on these pipeline systems, there is minimal impact on revenue.

Customers and Contracting

Great Lakes' average contracted capacity was 97 per cent of its design capacity for the second quarter of 2009 compared to 95 per cent for the same period last year. At June 30, 2009, 96 per cent of its average design capacity was contracted on a firm basis for the remainder of the year and the weighted average remaining life of firm transport contracts was 2.4 years. Great Lakes' competitive rate combined with strong spread values between Alberta and Dawn, Ontario continued to support strong transportation values for Great Lakes, which was able to take advantage of daily sales in the short-term market.

Northern Border's average contracted capacity was 55 per cent of its design capacity for the second quarter of 2009 compared to 74 per cent for the same period last year. At June 30, 2009, Northern Border had approximately 49 per cent of its design capacity uncontracted beginning in the third quarter of 2009 and approximately 53 per cent uncontracted beginning in the fourth quarter of 2009. Prevailing market conditions and competitive factors in North America, including the Rockies Express Pipeline, will continue to impact the value of Northern Border's transportation and its ability to market available capacity. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue. As at June 30, 2009, the weighted average remaining life of Northern Border's firm transportation contracts was 2.4 years.

Tuscarora operates under long-term contracts and had 98 per cent of its design capacity contracted for the second quarter of 2009 compared to 95 per cent for the same period last year. As at June 30, 2009, 98 per cent of its design capacity was contracted on a firm basis for the remainder of the year with a weighted average remaining life of 11.2 years.

North Baja operates under long-term contracts and, as at June 30, 2009, in excess of 100 per cent of its physical capacity was contracted on a firm basis for the remainder of the year. The weighted average remaining life of the contracts at June 30, 2009 was 16.6 years.

Competition

Our pipeline systems compete primarily with other interstate and intrastate pipelines in the transportation of natural gas. Additionally, supply competition from other natural gas sources can impact demand for transportation on our pipeline systems. Growth in supplies available from other natural gas producing regions can impact prices for natural gas delivered to some of the markets our pipeline systems serve relative to other market regions.

Factors impacting the competition for Net WCSB Flows to Markets during the remainder of 2009 will include high natural gas storage levels in Eastern Canada and California.

Changes in North American gas flow patterns are expected as a result of new pipeline projects which will change the supply competition in the markets served by our pipeline systems.

REX West introduced new gas supplies from the Rockies gas basin into the markets served by Northern Border in the second quarter of 2008. The Eastern segment of the Rockies Express Pipeline (REX East) was placed into interim service on June 29, 2009 to Lebanon, Ohio. Rockies Express Pipeline has announced that full in-service of REX East to Clarington, Ohio is scheduled for November 2009. REX East is mitigating excess supply in the Mid-Continent region which is resulting in a reduction in the downward pressure on prices experienced following the REX West project. The movement of these natural gas supplies further east is expected to create additional supply in the markets Great Lakes serves, but may also provide opportunities for Great Lakes to market its Eastern zone capacity for storage injection and withdrawal. As well, there may be increased supply in the Chicago market served by Northern Border as a result of the in-service of REX East.

Two new pipeline projects to transport volumes from the lower Mid-Continent east to the existing Gulf Coast pipeline infrastructure went into service in the second quarter of 2009. These pipelines transport volumes from the lower Mid-Continent east to existing pipelines that can deliver this supply to the Chicago market area, Eastern U.S. market area, or to the Gulf market depending on demand. Additional supply in the Chicago market may continue to impact Northern Border's ability to contract upstream available capacity for the remainder of 2009 if natural gas flows to Chicago materially decrease.

REGULATORY DEVELOPMENTS

Other Laws and Regulations

U.S. Congress is actively considering federal legislation to reduce emissions of "greenhouse gases" (including carbon dioxide and methane). The House of Representatives narrowly approved the Waxman-Markey Bill on June 26, 2009. The legislation is now under consideration by the Senate, and could be rejected by the Senate, or could be significantly amended before being approved by the Senate. If passed, such legislation could result in increased costs to (i) operate and maintain our pipeline systems' facilities; (ii) install new emission controls on our pipeline systems' facilities; (iii) require the construction of new facilities; and (iv) administer and manage any greenhouse gas emissions reduction program that may be applicable to our pipeline systems' operations. Separately, the EPA has proposed regulations relating to monitoring and reporting greenhouse gas emissions pursuant to its authority under the Clean Air Act. While our pipeline systems may be able to include some or all of the costs associated with this environmental compliance, including future compliance with greenhouse gas laws and regulations, in its transportation rates, the ability to recover such costs is uncertain and may depend on events beyond our pipeline systems' control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

On February 2, 2009, Northern Border received a Notice of Violation (NOV) from the EPA alleging that Northern Border was in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on its system. Northern Border disputes the NOV. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty.

RESULTS OF OPERATIONS OF TC PIPELINES

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. generally accepted accounting principles (GAAP) requires us to make estimates and assumptions with respect to values or conditions which cannot be known with certainty, that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ. There were no significant changes to our critical accounting policies and estimates during the six months ended June 30, 2009.

Information about our critical accounting estimates is included under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in our Annual Report on Form 10-K for the year ended December 31, 2008.

Recent Accounting Pronouncements

The Partnership adopted the provision of Statement of Financial Accounting Standards (SFAS) No. 157-2, *Effective Date of FASB Statement No. 157* (SFAS 157-2), for all non-financial assets and liabilities measured on a recurring basis, effective January 1, 2009. The adoption of SFAS 157-2 has had no material impact on our results of operations or financial position.

The Emerging Issues Task Force of the Financial Accounting Standards Board (FASB) issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per share*, to Master Limited Partnerships," which was ratified by the FASB in March 2008. EITF 07-4 is effective for fiscal years beginning after December 15, 2008. The Partnership adopted the provisions of EITF 07-4 effective January 1, 2009. Refer to Note 6 for the impact to our financial statements.

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Net Income

To supplement our financial statements, we have presented a comparison of the earnings contribution components from each of our investments. We have presented net income in this format in order to enhance investors' understanding of the way management analyzes our financial performance. We believe this summary provides a more meaningful comparison of our net income to prior periods, as we account for our partially owned pipeline systems using the equity method. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

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

(unaudited)	**Three months ended June 30, 2009**					**Six months ended June 30, 2009**				
(millions of dollars)	**PipeLP**	TGTC	Other	GLGT	NBPC[1]	**PipeLP**	TGTC	Other	GLGT	NBPC[1]
Transmission revenues	**8.2**	8.2	-	69.0	54.2	**16.6**	16.6	-	151.5	128.7
Operating expenses	**(4.1)**	(1.2)	(2.9)	(17.1)	(18.3)	**(6.7)**	(2.6)	(4.1)	(33.1)	(36.8)
	4.1	7.0	(2.9)	51.9	35.9	**9.9**	14.0	(4.1)	118.4	91.9
Depreciation	**(1.7)**	(1.7)	-	(14.6)	(15.5)	**(3.5)**	(3.5)	-	(29.2)	(30.8)
Financial charges, net and other	**(7.0)**	(1.2)	(5.8)	(8.1)	(9.2)	**(14.3)**	(2.3)	(12.0)	(16.3)	(18.3)
Michigan business tax	-	-	-	(1.3)	-	-	-	-	(3.1)	-
				27.9	11.2				69.8	42.8
Equity income	**18.3**	-	-	12.9	5.4	**53.4**	-	-	32.4	21.0
Net income	**13.7**	4.1	(8.7)	12.9	5.4	**45.5**	8.2	(16.1)	32.4	21.0

(unaudited)	Three months ended June 30, 2008					Six months ended June 30, 2008				
(millions of dollars)	PipeLP	TGTC	Other	GLGT	NBPC[(1)]	PipeLP	TGTC	Other	GLGT	NBPC[(1)]
Transmission revenues	8.2	8.2	-	67.5	61.3	15.1	15.1	-	147.2	145.1
Operating expenses	(2.3)	(1.1)	(1.2)	(13.7)	(18.8)	(4.5)	(2.3)	(2.2)	(28.8)	(38.2)
	5.9	7.1	(1.2)	53.8	42.5	10.6	12.8	(2.2)	118.4	106.9
Depreciation	(1.7)	(1.7)	-	(14.6)	(15.3)	(3.3)	(3.3)	-	(29.2)	(30.5)
Financial charges, net and other	(7.5)	(1.1)	(6.4)	(8.2)	(9.5)	(15.1)	(2.0)	(13.1)	(16.4)	(19.2)
Michigan business tax	-	-	-	(1.3)	-	-	-	-	(3.0)	-
				29.7	17.7				69.8	57.2
Equity income	22.5	-	-	13.8	8.7	60.6	-	-	32.4	28.2
Net income	19.2	4.3	(7.6)	13.8	8.7	52.8	7.5	(15.3)	32.4	28.2

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

Second Quarter 2009 Compared with Second Quarter 2008

Net income was $13.7 million in the second quarter of 2009, a decrease of $5.5 million compared to $19.2 million in the second quarter of 2008. This decrease is primarily due to lower equity income from both Northern Border and Great Lakes, and increased operating expenses.

Equity income from Great Lakes decreased $0.9 million to $12.9 million in the second quarter of 2009, compared to $13.8 million for the same period last year. The decrease in equity income was primarily due to increased operating expenses, partially offset by increased transmission revenues. Great Lakes' operating expenses increased $3.4 million for the three months ended June 30, 2009 primarily due to increased pipeline integrity expenses and property taxes. Great Lakes' transmission revenues increased $1.5 million for the three months ended June 30, 2009 compared to the same period last year, primarily due to an increase in sales of short-term services, partially offset by decreased long-term services as a result of capacity turnbacks and renewed capacity at lower rates.

Equity income from Northern Border was $5.4 million in the second quarter of 2009, a decrease of $3.3 million compared to $8.7 million for the same period last year. The decrease in equity income was primarily due to decreased transmission revenues, partially offset by lower operating expenses. Northern Border's transmission revenues decreased by $7.1 million for the three months ended June 30, 2009 compared to the same period last year primarily due to reduced system utilization, as Northern Border continues to be negatively impacted by the incremental natural gas supply from the Rockies Basin into the Mid-Continent market as a result of the in-service of REX West. Operating expenses decreased $0.5 million in the second quarter of 2009 compared to the same period last year primarily as a result of decreased property taxes.

Tuscarora's net income of $4.1 million in the second quarter of 2009 is comparable to the same period last year.

Costs at the Partnership level increased by $1.1 million to $8.7 million in the second quarter of 2009 compared to the same period last year. This increase is due to higher operating expenses, partially offset by decreased financial charges, net and other. Operating expenses increased by $1.7 million primarily due to costs relating to the North Baja acquisition and the amendment to the IDRs. Financial charges, net and other decreased by $0.6 million primarily due to lower interest rates and average debt outstanding, partially offset by losses on interest rate derivatives.

Six Months Ended June 30, 2009 Compared with Six Months Ended June 30, 2008

Net income decreased $7.3 million to $45.5 million for the six months ended June 30, 2009 compared to $52.8 million in the same period last year. This decrease is primarily due to lower equity income from Northern Border and increased operating expenses in 2009, partially offset by higher transmission revenue from Tuscarora and lower financial charges, net and other.

Equity income from Great Lakes was $32.4 million for the six months ended June 30, 2009, which is consistent with the same period last year. Great Lakes' transmission revenues increased by $4.3 million due primarily to an increase in sales of short-term services as a result of available capacity, partially offset by decreased long-term services as a result of capacity turnbacks and renewed capacity at lower rates. Great Lakes' operating expenses increased $4.3 million for the six months ended June 30, 2009 compared to the same period in the prior year primarily due to increased pipeline integrity, repairs and overhauls and other operational expenses.

Equity income from Northern Border was $21.0 million for the six months ended June 30, 2009, a decrease of $7.2 million compared to $28.2 million in the same period last year. The decrease in equity income was primarily due to decreased transmission revenues, partially offset by lower operating expenses and lower financial charges, net and other. Northern Border's transmission revenues decreased by $16.4 million for the six months ended June 30, 2009 compared to the same period last year, primarily due to reduced system utilization, as Northern Border continues to be negatively impacted by the incremental natural gas supply from the Rockies Basin into the Mid-Continent market as a result of the in-service of REX West. Northern Border's operating expenses decreased by $1.4 million primarily due to lower general and administrative costs. Northern Border's financial charges, net and other decreased by $0.9 million, primarily due to increased miscellaneous income and decreased interest rates, partially offset by an increase in average debt outstanding.

Tuscarora's net income was $8.2 million for the six months ended June 30, 2009, an increase of $0.7 million compared to $7.5 million in the same period last year. This increase is primarily due to higher transmission revenues resulting from the Likely compressor station expansion project that went into service on April 1, 2008.

Costs at the Partnership level increased by $0.8 million to $16.1 million for the six months ended June 30, 2009 compared to the same period last year. This increase is due to higher operating expenses, partially offset by decreased financial charges, net and other. Operating expenses increased by $1.9 million primarily due to costs relating to the North Baja acquisition and the amendment to the IDRs. Financial charges, net and other decreased by $1.1 million primarily due to lower interest rates and lower average debt outstanding, partially offset by losses on interest rate derivatives.

Partnership Cash Flows

The Partnership uses the non-GAAP financial measures "Partnership cash flows" and "Partnership cash flows allocated to common units" as financial performance measures. As the Partnership's financial performance underpins the availability of cash flows to fund the cash distributions that the Partnership pays to its unitholders, the Partnership believes these are key measures of the available cash flows to its unitholders. The following Partnership cash flows information is presented to enhance investors' understanding of the way that management analyzes the Partnership's financial performance. Partnership cash flows and Partnership cash flows allocated to common units are provided as a supplement to financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP.

(unaudited) *(millions of dollars except per common unit amounts)*	**Three months ended June 30, 2009**	2008	**Six months ended June 30, 2009**	2008
Net Income	**13.7**	19.2	**45.5**	52.8
Add:				
Cash flows provided by Tuscarora's operating activities	**4.8**	4.1	**12.0**	10.1
Cash distributions from Great Lakes [(1)]	**21.7**	24.1	**34.2**	35.7
Cash distributions from Northern Border [(1)]	**22.5**	26.3	**46.7**	49.4
	49.0	54.5	**92.9**	95.2
Less:				
Tuscarora's net income	**(4.1)**	(4.3)	**(8.2)**	(7.5)
Equity income from investment in Great Lakes	**(12.9)**	(13.8)	**(32.4)**	(32.4)
Equity income from investment in Northern Border	**(5.4)**	(8.7)	**(21.0)**	(28.2)
	(22.4)	(26.8)	**(61.6)**	(68.1)
Partnership cash flows	**40.3**	46.9	**76.8**	79.9
Partnership cash flows allocated to general partner [(2)]	**(3.2)**	(3.2)	**(6.4)**	(6.2)
Partnership cash flows allocated to common units	**37.1**	43.7	**70.4**	73.7
Cash distributions declared	**(30.7)**	(27.8)	**(58.5)**	(55.2)
Cash distributions declared per common unit [(3)]	**$ 0.730**	$ 0.705	**$ 1.435**	$ 1.405
Cash distributions paid	**(27.8)**	(27.4)	**(55.5)**	(53.0)
Cash distributions paid per common unit [(3)]	**$ 0.705**	$ 0.700	**$ 1.410**	$ 1.365
Weighted average common units outstanding *(millions)*	**34.9**	34.9	**34.9**	34.9

(1) In accordance with the cash distribution policies of the respective pipeline assets, cash distributions from Great Lakes and Northern Border are based on their respective prior quarter financial results.

(2) Partnership cash flows allocated to general partner represents the cash distributions declared to the general partner with respect to its two per cent interest plus an amount equal to incentive distributions. Prior to 2009, Partnership cash flows allocated to general partner were based on the cash distributions paid during the quarter to the general partner. As a result of the retrospective application of EITF 07-4, Partnership cash flows allocated to general partner in the second quarter of 2008 increased from $3.0 million to $3.2 million. Partnership cash flows allocated to the general partner for the six months ended June 30, 2008 increased from $5.4 million to $6.2 million.

(3) Cash distributions declared per common unit and cash distributions paid per common unit are computed by dividing cash distributions, after the deduction of the general partner's allocation, by the number of common units outstanding. The general partner's allocation is computed based upon the general partner's two per cent interest plus an amount equal to incentive distributions.

Second Quarter 2009 Compared with Second Quarter 2008

Partnership cash flows decreased $6.6 million to $40.3 million for the second quarter of 2009 compared to $46.9 million for the same period of last year. This decrease is primarily a result of decreased cash distributions from Northern Border and Great Lakes, in addition to higher costs at the Partnership level, partially offset by increased cash flows provided by Tuscarora's operating activities. Northern Border's decreased distribution was primarily due to lower net income, partially offset by a reduction in maintenance capital expenditures. Great Lakes' decreased distribution was primarily due to scheduled debt repayments, partially offset by lower maintenance capital expenditures. Costs at the Partnership level increased due to costs relating to the North Baja acquisition and the amendment to the IDRs, partially offset by lower financial charges, net and other. Cash flows provided by Tuscarora's operating activities increased primarily due to decreases in working capital.

The Partnership paid distributions of $27.8 million in the second quarter of 2009, an increase of $0.4 million compared to the same period in the prior year due to an increase in quarterly per common unit distribution amounts. We repaid $2.3 million of our outstanding debt balance during the three months ended June 30, 2009, compared to $16.3 million for the same period in the prior year.

Six Months Ended June 30, 2009 Compared with Six Months Ended June 30, 2008

Partnership cash flows decreased $3.1 million to $76.8 million for the six months ended June 30, 2009 compared to $79.9 million for the same period of last year. This decrease is primarily a result of decreased cash distributions from Northern Border and Great Lakes, in addition to higher costs at the Partnership level, partially offset by increased cash flows provided by Tuscarora's operating activities. Northern Border's decreased distribution was primarily due to lower net income, partially offset by a reduction in maintenance capital expenditures. Great Lakes' decreased distribution was primarily due to scheduled debt repayments, partially offset by lower maintenance capital expenditures. Costs at the Partnership level increased due to costs relating to the North Baja acquisition and the amendment to the IDRs, partially offset by lower financial charges, net and other. Cash flows provided by Tuscarora's operating activities increased primarily due to higher transmission revenues resulting from the Likely compressor station expansion project that went into service on April 1, 2008.

The Partnership paid distributions of $55.5 million in the six months ended June 30, 2009, an increase of $2.5 million compared to the same period in the prior year due to an increase in quarterly per common unit distribution amounts. We repaid $2.3 million of our outstanding debt balance during the six months ended June 30, 2009, compared to $24.3 million for the same period in the prior year.

During the six months ended June 30, 2009, the Partnership made an equity contribution of $4.3 million to Northern Border, representing the Partnership's 50 per cent share of an $8.6 million cash call issued by Northern Border to complete the Des Plaines Project.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES

Overview

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

The Partnership's Debt and Credit Facility

The following table summarizes our debt and credit facility outstanding as of June 30, 2009:

	Payments Due by Period		
(unaudited) *(millions of dollars)*	Total	Less Than 1 Year	Long-term Portion
Senior Credit Facility due 2011	475.0	-	475.0
7.13% Series A Senior Notes due 2010	49.7	3.1	46.6
7.99% Series B Senior Notes due 2010	4.7	0.5	4.2
6.89% Series C Senior Notes due 2012	5.1	0.8	4.3
Total	534.5	4.4	530.1

TC PipeLines' revolving credit and term loan agreement (Senior Credit Facility) consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility. At June 30, 2009, no draws were made on our senior revolving credit facility; however, a $170.0 million draw was made subsequently to partially fund the North Baja acquisition.

The interest rate on the Senior Credit Facility averaged 1.65 per cent for the three months ended June 30, 2009 (2008 - 3.44 per cent), while for the six months ended June 30, 2009 the interest rate on the Senior Credit Facility averaged 2.04 per cent (2008 - 4.24 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.76 per cent for the three months ended June 30, 2009 (2008 - 5.02 per cent) and 4.91 per cent for the six months ended June 30, 2009 (2008 - 5.15 per cent). Prior to hedging activities, the interest rate was 1.19 per cent at June 30, 2009 (December 31, 2008 - 2.67 per cent). At June 30, 2009, we were in compliance with our financial covenants.

Interest Rate Swaps and Options

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged at June 30, 2009 was $375.0 million (December 31, 2008 - $475.0 million). At June 30, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $25.3 million (December 31, 2008 - negative $31.7 million). Under Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS 157), financial instruments are recorded at fair value on a recurring basis. We have classified all our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. During the three and six months ended June 30, 2009, we recorded interest expense of $3.7 million and $6.9 million in regards to the interest rate swaps and options. In 2008, we recorded interest expense of $2.0 million and $2.3 million for the three and six months ended June 30 in regards to the interest rate swaps and options. These expenses are included in the line item "Financial charges, net and other" on the Partnership's consolidated statement of income.

2009 Second Quarter Cash Distribution

On July 21, 2009, the Board of Directors of the general partner declared the Partnership's 2009 second quarter cash distribution in the amount of $0.73 per common unit. This cash distribution, totaling $30.7 million, will be paid on August 14, 2009 to unitholders of record as of July 31, 2009, in the following manner: $30.1 million to common unitholders (including $4.2 million to the general partner as holder of 5,797,106 common units and $8.2 million to TransCan Northern Ltd. as holder of 11,287,725 common units) and $0.6 million to the general partner in respect of its two per cent general partner interest. This distribution was calculated pursuant to the Second Amended and Restated Agreement of Limited Partnership dated July 1, 2009 which includes the IDR restructuring.

2009 Capital Requirements

Northern Border's distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by its Management Committee to establish the timing and amount of required equity contributions. In accordance with this policy, Northern Border currently estimates that it will require an equity contribution of approximately $76 million in the third quarter of 2009, of which the Partnership's share would be approximately $38 million. The Partnership expects to finance this equity contribution with a combination of debt and operating cash flows.

LIQUIDITY AND CAPITAL RESOURCES OF OUR PIPELINE SYSTEMS

Overview

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

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

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

Debt of Great Lakes

The following table summarizes Great Lakes' debt outstanding as of June 30, 2009:

(unaudited) *(millions of dollars)*	Payments Due by Period Total	Less than 1 year	Long-term Portion
8.74% series Senior Notes due 2007 to 2011	30.0	10.0	20.0
6.73% series Senior Notes due 2009 to 2018	81.0	9.0	72.0
9.09% series Senior Notes due 2012 to 2021	100.0	-	100.0
6.95% series Senior Notes due 2019 to 2028	110.0	-	110.0
8.08% series Senior Notes due 2021 to 2030	100.0	-	100.0
Total	421.0	19.0	402.0

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the Senior Note Agreements, approximately $227.0 million of Great Lakes' partners' capital was restricted as to distributions as of June 30, 2009 (December 31, 2008 - $232.0 million). As at June 30, 2009, Great Lakes was in compliance with all of its financial covenants.

Debt and Credit Facility of Northern Border

The following table summarizes Northern Border's debt and credit facility outstanding as of June 30, 2009:

(unaudited) *(millions of dollars)*	Payments Due by Period Total	Less than 1 year	Long-term Portion
7.75% senior notes due 2009	200.0	200.0	-
7.50% senior notes due 2021	250.0	-	250.0
$250 million credit agreement due 2012 [a]	190.0	-	190.0
Total	640.0	200.0	440.0

[a] Northern Border is required to pay a facility fee of 0.05% on the principal commitment amount of its credit agreement.

As of June 30, 2009, Northern Border had outstanding borrowings of $190.0 million under its $250.0 million revolving credit agreement and was in compliance with the covenants of the agreement. The weighted average interest rate related to the borrowings on its credit agreement was 1.10 per cent at June 30, 2009.

Senior Notes due 2009
On September 1, 2009, the $200.0 million of 7.75 per cent senior notes will mature. As market conditions dictate, Northern Border intends to refinance the senior notes with a combination of equity contributions from its partners, long-term fixed-rate and short-term variable-rate debt.

Interest Rate Collar Agreement
At June 30, 2009, Northern Border's balance sheet reflected an unrealized loss of approximately $2.5 million with a corresponding increase to accumulated other comprehensive loss related to the changes in fair value of its interest rate collar agreement (the "Collar Agreement") since inception. During the three and six months ended June 30, 2009, Northern Border recorded interest expense of $1.2 million and $2.0 million, respectively, under the Collar Agreement. The hedge was effective for the three and six months ended June 30, 2009; therefore, had no impact on net income.

RELATED PARTY TRANSACTIONS

Operating Agreements

Our pipeline systems, including the recently acquired North Baja, are operated by TransCanada and its affiliates pursuant to operating agreements. TransCanada has internally announced a reorganization of its U.S. operations, which will include the closing of certain offices, relocation of employees and equipment, and some severance costs, with certain operational cost savings to be expected in the future. According to our operating agreements, some of these costs could be borne by our pipeline systems. It is expected that the reorganization will be complete in 2010, with some activities possibly occurring in 2009.

Acquisition of North Baja and IDR Structuring

In connection with the acquisition of North Baja on July 1, 2009, the following transactions were consummated with certain TransCanada affiliates. The Partnership entered into a Common Unit Purchase Agreement (Purchase Agreement) with TransCan Northern Ltd. (TransCan Northern) to sell 2,609,680 newly issued, unregistered common units representing limited partner interests in the Partnership to TransCan Northern at a price per common unit of $30.042 for an aggregate amount of approximately $78.4 million (Offering). The Offering closed on July 1, 2009. TransCan Northern is a wholly-owned subsidiary of TransCanada, which is the ultimate parent company of TC PipeLines GP, Inc., the sole general partner of the Partnership.

The Partnership used the net proceeds from the offering to fund a portion of the cash consideration for the Partnership's acquisition of the 100 per cent interest in North Baja Pipeline, LLC (Acquisition).

The Partnership entered into an Exchange Agreement with TC PipeLines GP, Inc. pursuant to which the Partnership issued to the general partner Revised IDRs and 3,762,000 newly issued, unregistered common units representing limited partner interests in the Partnership in exchange for the cancellation of the Old IDRs under the Amended and Restated Agreement of Limited Partnership of the Partnership.

The Revised IDRs provide for distribution levels at two per cent, down from the distribution levels of the Old IDRs at 50 per cent. The distribution levels of the Revised IDRs increase to 15 per cent and are capped at 25 per cent when quarterly distributions increase to $0.81 and $0.88 per common unit or $3.24 and $3.52 per common unit on an annualized basis, respectively. The quarterly distribution level of the Old IDRs was $0.705 per common unit or $2.82 on an annualized basis.

As a result of the closing of the Acquisition and the transactions pursuant to the Purchase Agreement and Exchange Agreement, TransCanada and its affiliates own 17,084,831 common units, representing an aggregate 40.6 per cent limited partner interest in the Partnership. In addition, the general partner owns an aggregate two per cent general partner interest in the Partnership (and its subsidiary limited partnerships on a combined basis) through which it manages and operates the Partnership. As a result, TransCanada's aggregate ownership interest in the Partnership (and its subsidiary limited partnerships on a combined basis) is 42.6 per cent by virtue of its indirect ownership of the general partner and 40.6 per cent aggregate limited partner interest.

The conflicts committee of the board of directors of the general partner, which is comprised entirely of independent directors, unanimously recommended approval by the board of directors of the Acquisition, the Offering, the Exchange Agreement and the terms of the Second Amended and Restated Agreement of Limited Partnership of the Partnership. The conflicts committee retained independent legal and financial advisors to assist it in evaluating and negotiating the Acquisition, the Offering and the Exchange Agreement. The board of directors of the General Partner unanimously approved the terms of the Acquisition, the Offering, the Exchange Agreement and the Second Amended and Restated Agreement of Limited Partnership of the Partnership.

Transportation Agreements

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed price contracts with remaining terms ranging from one to nine years. Great Lakes earned $35.1 million of transportation revenues under these contracts for the three months ended June 30, 2009 (2008 - $37.9 million). This amount represents 50.9 per cent of total revenues earned by Great Lakes for the three months ended June 30, 2009 (2008 - 56.1 per cent). $16.3 million of affiliated revenue is included in our equity income from Great Lakes for the three months ended June 30, 2009 (2008 - $17.6 million).

Great Lakes earned $72.4 million of transportation revenues from TransCanada and its affiliates for the six months ended June 30, 2009 (2008 - $68.2 million). This amount represents 47.8 per cent of total revenues earned by Great Lakes for the six months ended June 30, 2009 (2008 - 46.3 per cent). $33.6 million of this transportation revenue is included in our equity income from Great Lakes for the six months ended June 30, 2009 (2008 - $31.7 million).

At June 30, 2009, $12.1 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2008 - $12.5 million).

Please read Note 8 within Item 1. "Financial Statements" for additional information regarding related party transactions.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that would occur assuming hypothetical future movements in interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates and the timing of transactions.

We are exposed to market risk due to interest rate fluctuations. Market risk is the risk of loss arising from adverse changes in market rates. We utilize financial instruments to manage the risks of certain identifiable or anticipated transactions to achieve a more predictable cash flow. Our risk management function follows established policies and procedures to monitor interest rates to ensure our hedging activities mitigate market risks. Our primary risk management objective is to protect earnings and cash flow, and ultimately unitholder value. We do not use financial instruments for trading purposes.

In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (SFAS 133) we record derivative financial instruments on the balance sheet as assets and liabilities based on fair value. We estimate the fair value of financial instruments using available market information and appropriate valuation techniques. Changes in these financial instruments' fair value are recognized in earnings unless the instrument qualifies as a hedge under SFAS 133 and meets specific hedge accounting criteria. Qualifying financial instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

MARKET RISK AND INTEREST RATE RISK

From time to time, and in order to finance our business and that of our pipeline systems, the Partnership and our pipeline systems incur debt to invest in growth opportunities and provide for ongoing operations. The issuance of debt exposes the Partnership and our pipeline systems to market risk from changes in interest rates which affect earnings and the value of the financial instruments we hold.

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

- Swaps - contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Partnership and our pipeline systems enter into interest rate swaps to mitigate the impact of changes in interest rates.

- Options - contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period. The Partnership and our pipeline systems enter into option agreements to mitigate the impact of changes in interest rates.

Interest rate risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in the market interest rates. Our interest rate exposure results from our Senior Credit Facility, which is subject to variability in London Interbank Offered Rate (LIBOR) interest rates. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk. The notional amount hedged at June 30, 2009 was $375.0 million (December 31, 2008 - $475.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid is 3.86 per cent. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The fair value of interest rate derivatives has been calculated using period-end market rates. At June 30, 2009, the fair value of the Partnership's interest rate swaps accounted for as hedges was negative $25.3 million (December 31, 2008 - negative $31.7 million), of which $10.8 million is classified as a current liability (December 31, 2008 - $11.8 million). The fair value of the interest rate swaps is calculated using the period-end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change.

At June 30, 2009, we had $475.0 million outstanding on our Senior Credit Facility. Utilizing the conditions of the interest rate swaps, if LIBOR interest rates hypothetically increased by one per cent (100 basis points) compared to the rates in effect as of June 30, 2009, our annual interest expense would have increased and our net income would have decreased by $1.0 million; and if LIBOR interest rates hypothetically decreased by one per cent (100 basis points) compared to the rates in effect as of June 30, 2009, our annual interest expense would have decreased and our net income would have increased by $1.0 million. These amounts have been determined by considering the impact of the hypothetical interest rates on unhedged debt outstanding as of June 30, 2009.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its credit facility. Northern Border regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. As of June 30, 2009, 70 per cent of Northern Border's outstanding debt was at fixed rates (December 31, 2008 - 71 per cent). Northern Border utilizes its Collar Agreement to limit the variability of the interest rate on $140.0 million of variable-rate borrowings through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent.

Utilizing the conditions of the Collar Agreement, if interest rates hypothetically increased by one per cent (100 basis points) compared with rates in effect as of June 30, 2009, Northern Border's annual interest expense would increase and its net income would decrease by approximately $0.5 million; and if interest rates hypothetically decreased by one per cent (100 basis points) compared with rates in effect as of June 30, 2009, Northern Border's annual interest expense would decrease and its net income would increase by approximately $0.5 million.

Northern Border has $200.0 million of senior notes maturing September 1, 2009. As market conditions dictate, Northern Border intends to refinance the senior notes with a combination of equity contributions from its partners, fixed-rate and short-term variable-rate debt.

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

OTHER RISKS

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

Counterparty credit risk represents the financial loss that the Partnership and our pipeline systems would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Partnership or its pipeline systems. Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consist primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets. At June 30, 2009, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $2.7 million (December 31, 2008 - $2.9 million).

The Partnership and our pipeline systems have significant credit exposure to financial institutions as they provide committed credit lines and critical liquidity in the interest rate derivative market, as well as letters of credit to mitigate exposures to non-creditworthy parties. Due to the deterioration of global financial markets in 2008 and 2009, we continue to closely monitor the creditworthiness of our counterparties, including financial institutions. Overall, we do not believe the Partnership and our pipeline systems have any significant concentrations of counterparty credit risk.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they fall due. Our approach to managing liquidity risk is to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation. At June 30, 2009, the Partnership has a committed revolving bank line of $250.0 million maturing in December 2011. As of June 30, 2009, no draws were made on this facility; however, $170.0 million was drawn on July 1, 2009 to partially fund the North Baja acquisition. In addition, at June 30, 2009, Northern Border has a committed revolving bank line of $250.0 million maturing in April 2012. As of June 30, 2009, $190.0 million was drawn on this facility.

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

The Partnership does not have any material foreign exchange risks.

Item 4. 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 period covered by this quarterly report, the principal executive officer and principal financial officer of the general partner of the Partnership have concluded that the Partnership's disclosure controls and procedures were effective in ensuring that the information required to be disclosed by the Partnership in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that information required to be disclosed by the Partnership in the reports that the Partnership files or submits under the Exchange Act is accumulated and communicated to the management of the general partner of the Partnership, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the quarter ended June 30, 2009, there has been no change in the Partnership's internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1A. Risk Factors

The following updated risk factor should be read in conjunction with the risk factors disclosed in Part I, Item 1A, "Risk Factors", in our Annual Report on Form 10-K for the year ended December 31, 2008.

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

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

The U.S. Congress is actively considering federal legislation to reduce emissions of "greenhouse gases" (including carbon dioxide and methane). The House of Representatives narrowly approved the Waxman-Markey Bill on June 26, 2009 ("Waxman-Markey Bill"). The legislation is now under consideration by the Senate, and could be rejected by the Senate, or could be significantly amended before being approved by the Senate. Several states of the U.S. have already taken legal measures to reduce emissions of greenhouse gases. At this time, it is unclear what our pipeline systems future environmental compliance costs relating to greenhouse gases will be or if the Waxman-Markey Bill will be adopted in its current form. Various federal and state legislative proposals have been made over the last several years and it is possible that legislation will be enacted in the future that could negatively impact the operations of our pipeline systems and our financial results. The level of such impact will likely depend upon whether any of our pipeline systems' facilities will be directly responsible for compliance with any adopted program; whether cost containment measures will be available; the ability of our pipeline systems to recover compliance costs from their customers; and the manner in which allowances are provided. At the federal regulatory level, the U.S. Environmental Protection Agency (EPA) has requested public comments on the potential regulation of greenhouse gases under the Clean Air Act. It is uncertain whether the EPA will proceed with adopting final rules or whether the regulation of greenhouse gases will be addressed in federal and state legislation.

It is uncertain what impact these actions might have on our pipeline systems until further definition is known; there is risk that such future measures could result in changes to the operations of our pipeline systems and to the consumption and demand for natural gas. If passed, changes to the operations of our pipeline systems could include increased costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; (iii) construct new facilities; and (iv) administer and manage any greenhouse gas emissions reduction program that may be applicable to our operations. Separately, the EPA has proposed regulations relating to monitoring and reporting greenhouse gas emissions pursuant to its authority under the Clean Air Act. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental compliance, including future compliance with greenhouse gas laws and regulations, in the rates charged by our pipeline systems, their ability to recover such costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

One of our pipeline systems, Northern Border, received a Notice of Violation (NOV) from the EPA on February 2, 2009 alleging that Northern Border was in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on its system. Northern Border disputes the NOV. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty.

Item 6. Exhibits

No.	Description
*2.1	Agreement for Purchase and Sale of Membership Interest dated May 19, 2009 by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on May 20, 2009 (File No. 000-26091)).
*3.1	Second Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated July 1, 2009 (Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009 (File No. 000-26091)).
*10.1	Common Unit Purchase Agreement dated July 1, 2009 by and between TC PipeLines, LP and TransCan Northern Ltd. (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009 (File No. 000-26091)).
10.2	Management Services Agreement dated January 1, 2002 by and between Gas Transmission Service Company, LLC (formally PG&E Gas Transmission Service Company, LLC) and North Baja Pipeline, LLC.
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 the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

TC PipeLines, LP
(a Delaware Limited Partnership)

By: TC PipeLines GP, Inc., its general partner

Date: August 4, 2009

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

Date: August 4, 2009

By: /s/ Amy W. Leong
Amy W. Leong
Controller
TC PipeLines GP, Inc. (Principal Financial Officer)

Exhibit 10.2

MANAGEMENT SERVICES AGREEMENT

This Management Services Agreement is made and entered into as of the 1st day of January, 2002, by and between PG&E Gas Transmission Service Company, LLC, a Delaware limited liability company ("ServiceCo"), and North Baja Pipeline, LLC, a Delaware Limited Liability Company ("Pipeline").

WHEREAS, Pipeline is in the process of developing, and will own and operate, a FERC-regulated interstate natural gas pipeline extending from an interconnection with El Paso Natural Gas near Ehrenberg, Arizona to an interconnection with Gasoducto Bajanorte near the U.S.-Mexico border between Yuma, Arizona and Mexicali, Baja California, Mexico;

WHEREAS, ServiceCo is an entity engaged in managing and operating natural gas pipeline facilities; and

WHEREAS, Pipeline and ServiceCo desire to enter into this Management Services Agreement pursuant to which ServiceCo shall manage the day-to-day affairs of Pipeline;

NOW, THEREFORE, in consideration of the promises and mutual covenants and provisions contained in this Agreement and subject to all terms and conditions set forth below, Pipeline and ServiceCo hereby agree as follows:

1. Appointment as Manager. Subject to the terms and conditions of this Management Services Agreement, Pipeline hereby appoints ServiceCo to act as Manager hereunder, and ServiceCo hereby accepts such appointment and agrees to act pursuant to the provisions of this Management Services Agreement. The Manager shall function as an independent contractor under this Management Services Agreement, and shall in no event ever act as, or be considered to be, an employee of Pipeline.

2. Manager's General Authority. The Manager is authorized to conduct the business and affairs of Pipeline in accordance with the Annual Business Plan (as defined in Section 4 herein) and other provisions of this Agreement. Except as otherwise expressly provided in this Management Services Agreement, the Manager shall have full and complete authority, power and discretion to execute contracts and manage and control the business, affairs and properties of Pipeline, to make all decisions regarding those matters and to perform any and all other acts or activities customary or incident to the management of Pipeline's business. Without limiting the foregoing, the Manager shall have the authority to make decisions with respect to the engineering, design, construction, regulatory approvals for, and operation (including physical operation, scheduling and dispatch of gas inventory) of Pipeline. The Manager shall not exceed the authority granted to the Manager by this Management Services Agreement.

3. Manager's Specific Duties.

   The Manager shall be responsible for the operation of Pipeline's interstate pipeline facilities in accordance with sound, workmanlike and prudent practices of the natural gas pipeline industry and in compliance with Pipeline's FERC Gas Tariff and with all applicable laws, statutes, ordinances, safety codes, regulations, rules and authorizations and requirements of governmental authorities having jurisdiction. Accordingly, subject to the provisions of this Management Services Agreement, the Manager shall:

   3.1.1 Provide or cause to be provided the day-to-day operating and maintenance services, administrative liaison and related services to Pipeline, including, but not limited to, customer support, legal, accounting, human resources, procurement, electronic bulletin board, engineering, construction, repair, replacement, inspection, operational planning, budgeting, tax and technical services, and insurance and regulatory administration.

   3.1.2 Upon prior approval by Pipeline, file, execute and prosecute applications for the authorizations required by Pipeline for the acquisition, construction, ownership and operation of facilities and the provision of the transportation services on the facilities. The Manager also shall make routine and periodic filings required of Pipeline by governmental authorities having jurisdiction.

3.1.3 Review from time to time the rates and fees charged for the transportation services, recommend appropriate rate revisions to Pipeline, prepare, and upon prior approval by Pipeline, file, execute and prosecute rate change filings.

3.1.4 Review from time to time the services offered by Pipeline, and recommend and implement improvements or additions to such service.

3.1.5 Prepare financing plans for Pipeline and negotiate financing commitments, if any, to be entered into by Pipeline, subject to final approval by Pipeline.

3.1.6 Negotiate and execute contracts for the purchase of services, materials, equipment and supplies necessary for the operation of Pipeline.

3.1.7 Prepare, negotiate and execute in the name of company rights-of-way, land in fee, permits and contracts, and, unless otherwise directed by Pipeline, initiate, prosecute and settle (if applicable) eminent domain condemnation proceedings, necessary for construction, operation and maintenance of the Facilities, and resist the perfection of any involuntary liens against Pipeline property.

3.1.8 Construct and install, or cause to be constructed and installed, facilities necessary for the safe and efficient operation of Pipeline, including expansions thereto.

3.1.9 Make reports to and consult with Pipeline regarding all duties, responsibilities and actions of the Manager under this Management Services Agreement in the form and at the times reasonably requested by Pipeline.

3.1.10 Maintain accurate and itemized accounting records for the operation of the Pipeline, together with any information reasonably required by Pipeline relating to such records.

3.1.11 Prepare financial reports.

3.1.12 Cause the operation of the Pipeline to be in accordance with all applicable laws, statutes, ordinances, safety codes, regulations, rules and authorizations and requirements of all governmental authorities having jurisdiction, including, but not limited to, local, state and federal environmental laws and the requirements of the United States Department of Transportation set forth in 49 C.F.R. Parts 192 and 199, and in accordance with sound, workmanlike and prudent practices of the natural gas industry and Pipeline's FERC Gas Tariff, and provide or cause to be provided such appropriate supervisory, audit, administrative, technical and other services as may be required for the operation of the Pipeline.

3.1.13 Prepare and file all necessary federal and state income tax returns and all other tax returns and filings for Pipeline. The Pipeline shall furnish to the Manager all pertinent information in its possession relating to Pipeline operations that is necessary to enable such returns to be prepared and filed.

3.1.14 Maintain and administer bank and investment accounts and arrangements for company funds, draw checks and other orders for the payment of money and designate individuals with authority to sign or give instructions with respect to those accounts and arrangements.

3.1.15 Negotiate, execute and administer the gas transportation contracts in accordance with Pipeline's FERC Gas Tariff, including, but not limited to, the preparation and collection of all bills to the shippers for services rendered thereunder; provided that the Manager shall execute gas transportation contracts for discounted firm or interruptible transportation services only to the extent the discounts are in accordance with Pipeline's discounting policy in effect from time to time, and provided further that any gas transportation contracts which require the construction of additional facilities for the performance thereof shall be subject to the prior approval of Pipeline.

3.1.16 Receive requests for service from shippers and potential shippers and issue confirmations for service in accordance with Pipeline's FERC Gas Tariff.

3.1.17 Recommend and establish guidelines for sale of capacity, including sales at discount and/or negotiated rates on a non-discriminatory basis.

3.1.18 Propose to Pipeline such procedures as may be reasonable and appropriate to comply with or to obtain an exemption from the marketing affiliate rules set forth in Part 161 of the FERC's regulations (as the same may be amended or superseded), and seek to implement such procedures as are approved by Pipeline.

3.1.19 Dispatch and allocate daily scheduled nominations for, and effectuate the physical receipt and delivery of, the natural gas quantities to be received, transported and/or delivered on behalf of the shippers in accordance with Pipeline's FERC Gas Tariff.

3.1.20 Utilize electronic flow measurement equipment for volume determinations and natural gas chromatographs as deemed appropriate by the Manager for heating value determinations at applicable metering points, as further described in Pipeline's FERC Gas Tariff.

3.1.21 Except as otherwise provided by applicable laws or governmental regulations or as otherwise directed by Pipeline, retain all books of account and Pipeline tax returns for three (3) years from the date of completion of the activity to which such records relate.

3.1.22 Procure and furnish on behalf of Pipeline all materials, equipment, supplies, services and labor necessary for, and perform, repairs to Pipeline's facilities that Manager determines to be appropriate and prudent.

3.1.23 Perform such other duties as are reasonably necessary or appropriate in the Manager's discretion and enter into such other arrangements as reasonably requested by Pipeline to discharge the Manager's responsibilities under this Management Services Agreement.

4. Manager's Budget and Annual Business Plan. Manager shall prepare an annual operating plan and budget for each year ("Annual Business Plan"), as it may be adjusted from time to time, setting forth estimates of management costs and other costs and expenses anticipated by Manager in connection with operating Pipeline. The approval by Pipeline of such Annual Business Plan shall constitute authorization for the Manager to incur the costs, expenses and expenditures set forth in such budget.

5. Claims. Any and all claims against Pipeline instituted by anyone other than the Manager arising out of the operation of the Facilities that are not covered by insurance in accordance with Section 9 of this Management Services Agreement shall be settled or litigated and defended by the Manager in accordance with its reasonable judgment and discretion except when (a) the amount involved is stated to be (or estimated to, as the case may be) greater than $1,000,000, or (b) criminal sanction is sought. The settlement or defense of any claim described in (a) or (b) above shall be decided by Pipeline. The Manager shall provide notice to Pipeline as soon as practicable of any claims instituted against Pipeline (regardless of the amount or nature of the claim).

6. Employees, Consultants and Subcontractors.

6.1 Initial Adoption by Manager of Pipeline Employees and Employee Obligations. Upon the Effective Date of this Management Services Agreement, Pipeline shall transfer to Manager all employees and employment-related agreements, and Manager shall employ all such employees and shall adopt, honor and continue all obligations and commitments related to such employees, specifically including, without limitation, salary and benefit agreements and elective deferral agreements under Internal Revenue Code Section 401k and employee elections under a cafeteria plan under Internal Revenue Code Section 125. Notwithstanding the foregoing, Pipeline shall remain responsible for, either primarily or as a successor employer, any assets or liabilities of any employee benefit plans, arrangements, commitments or policies provided by the Manager or any affiliate of the Manager; and if and to the extent that Pipeline is deemed by law or otherwise to be liable as a successor employer for such purposes, the Manager shall indemnify Pipeline for the full and complete costs, fees and other liabilities which result. In particular, but without limiting the generality of the foregoing, Pipeline shall not assume liability for any group health continuation coverage or coverage rights under Internal Revenue Code Section 4980B and ERISA Section 601 and related provisions which exist as of the Effective Date or which arise as a result of the Manager's dissolution and/or termination of its or any of its affiliate's group health plan or plans, and if and to the extent that Pipeline is deemed by law or otherwise to be liable as a successor employer for such group health continuation coverage purposes, the Manager shall indemnify Pipeline for the full and complete amount of any resulting costs, fees and other liabilities.

6.2 Manager's Employees, Consultants, Subcontractors and Independent Contractors. The Manager shall employ or retain and have supervision over the persons (including Manager's affiliates, consultants and professional service or other organizations) required or deemed advisable by the Manager to perform its duties and responsibilities hereunder in an efficient and economically prudent manner. The compensation for the Manager's employees shall be determined by the Manager, provided that the amount and terms of such compensation billed to Pipeline shall be comparable to those prevailing in the natural gas industry for similar work.

6.3 Standards for Manager and its Employees. The Manager shall perform its services and carry out its responsibilities hereunder, and shall require all of its employees and consultants, and contractors, subcontractors and materialmen furnishing labor, material or services for the operation of Pipeline to carry out their respective responsibilities in accordance with sound, workmanlike and prudent practices of the natural gas pipeline industry and in compliance with Pipeline's FERC Gas Tariff and with all applicable laws, statutes, ordinances, safety codes, regulations, rules, authorizations and requirements of governmental authorities having jurisdiction applicable to Pipeline's facilities. The Manager shall take reasonable measures to monitor the compliance of such employees and consultants, and contractors, subcontractors and materialmen, to these standards.

6.4 Non-Discrimination and Drugs. In performing under this Management Services Agreement, the Manager shall not discriminate against any employee or applicant for employment because of race, creed, color, religion, sex, national origin, age or disability, and will comply with all provisions of Executive Order 11246 of September 24, 1965, and any successor order thereto, to the extent that such provisions are applicable to the Manager or Pipeline. Neither Pipeline nor the Manager shall condone in any way the use of illegal drugs or controlled substances. Any person known by the Manager to be in possession of any illegal drug or controlled substance will be disciplined by the Manager and/or removed in accordance with the Manager's policies and procedures. In addition, the Manager shall meet all the applicable requirements imposed by the Department of Transportation as specified in 49 C.F.R., Parts 40 and 199 (as the same may be amended or superseded). Furthermore, upon request and to the extent permitted by law, the Manager will furnish Pipeline copies of the records of employee drug test results required to be kept under the provisions of 49 C.F.R. Part 199. The provisions of this Section 6.4 shall be applicable to any employees, contractors, consultants and subcontractors retained in connection herewith, and the Manager shall cause the agreements with any contractor, consultant or subcontractor to contain similar language.

7. Financial and Accounting.

7.1 Accounting and Compensation.

7.1.1 The Manager shall keep a full and complete account of all costs, expenses and expenditures incurred by it in connection with its obligations hereunder in the manner set forth in the Accounting Procedure attached hereto as Exhibit A, and shall otherwise keep a full and complete account of all accounts that Pipeline is required to maintain.

7.1.2 The Manager shall be reimbursed by Pipeline at the rate and in the manner set forth in the Accounting Procedure for all costs and expenses of the Manager incurred in accordance with this Management Services Agreement and in connection with the operation of Pipeline or otherwise to fulfill the Manager's duties under this Management Services Agreement.

7.1.3 Disputed Charges. Pipeline may, within the audit period referred to in Section 7.1.4 hereof, take written exception to any bill or statement rendered by the Manager for any expenditure or any part thereof on the ground that the same was not appropriate for reimbursement under the terms of Section 7.1.2 above. Pipeline shall nevertheless pay in full when due the amount of all statements submitted by the Manager. Such payment shall not be deemed a waiver of the right of Pipeline to recoup any contested portion of any bill or statement. If the amount as to which such written exception is taken or any part thereof is ultimately determined not to be appropriate for reimbursement under the terms of Section 7.1.2 of this Management Services Agreement, such amount or portion thereof (as the case may be) shall be refunded by the Manager to Pipeline, together with interest thereon at a rate (which in no event shall be higher than the maximum rate permitted by applicable law) equal to two percent (2%) per annum over the prime rate of Citibank, N.A. (or its successor) from time to time publicly announced and in effect, during the period from the date of payment by Pipeline to the date of refund by the Manager.

7.1.4 Audit and Examination. Pipeline shall have the right during normal business hours to audit or examine all books and records maintained by the Manager, including support for costs charged by the Manager's contractors, relating to the operation of Pipeline. The right to conduct an audit or examination shall include the right to meet with the Manager's internal and independent auditors to discuss matters relevant to the audit or examination. Pipeline shall have the right to conduct one (1) audit of the Manager's records for any twelve (12) month period.

8. Indemnification.

8.1 By Manager. Manager shall indemnify, defend, save, and hold harmless Pipeline and its affiliates, and all of their respective officers, directors, employees, agents, partners, shareholders and representatives, from and against any and all claims arising out of any actions by Manager, its officers, directors or employees which are outside the scope of Manager's authority under this Management Services Agreement, or actions or failures to act of Manager, its officers, directors or employees which in each case constitute gross negligence or willful misconduct; provided, however, that Manager's total aggregate liability hereunder during the term of this Management Services Agreement shall in no event exceed $500,000 over and above the amount covered by insurance.

8.2 By Pipeline. Pipeline shall indemnify, defend, save, and hold harmless Manager, its constituent partners and their affiliates, and all of their respective officers, directors, employees, agents, partners, shareholders and representatives, from and against any and all claims arising out of the acts (or failures to act), or for any obligation, liability, or commitment incurred by or on behalf of Pipeline as a result of any such acts (or failures to act); provided, however, that Manager, its officers, directors and employees shall not be entitled to indemnification hereunder for any claims resulting from their gross negligence or willful misconduct.

8.3 Other Claims. Except as otherwise provided in Sections 8.1 and 8.2, any and all suits or claims against Pipeline asserted by anyone other than Manager arising out of the design, construction, supervision, operations, maintenance or administration of Pipeline that are not covered by insurance shall be litigated and defended by Manager on behalf of Pipeline, in accordance with Manager's reasonable judgment and discretion.

8.4 Indemnification Notices. Whenever a party entitled to indemnification under Section 8.1 or 8.2 of this Management Services Agreement (an "Indemnitee") shall learn of a claim which, if allowed (whether voluntarily or by a judicial or quasi-judicial tribunal or agency), would entitled such Indemnitee to indemnification under Section 8.1 or 8.2 of this Management Services Agreement, before paying the same or agreeing thereto, the Indemnitee shall promptly notify the party required to pay such indemnification (the "Indemnitor") in writing of all material facts within the Indemnitee's knowledge with respect to such claim and the amount thereof; provided, however, that the Indemnitee's right to indemnification shall be diminished by the failure to give prompt notice only to the extent that the Indemnitee's failure to give such notice was prejudicial to the interests of the Indemnitor. If, prior to the expiration of fifteen (15) days from the giving of such notice, the Indemnitor shall request, in writing, that such claim not be paid, the Indemnitee shall not pay the same, provided that the Indemnitor proceeds promptly to settle or litigate, in good faith, such claim. The Indemnitee shall have the right to participate in any such negotiation, settlement or litigation. The Indemnitee shall not be required to refrain from paying any claim which has matured by a court judgment or decree, unless an appeal is duly taken therefrom and execution thereof has been stayed, nor shall it be required to refrain from paying any claim where the delay to pay such claim would result in the foreclosure of a lien upon any of the property of the Indemnitee, or where any delay in payment would cause the Indemnitee an economic loss, unless the Indemnitor shall have agreed to compensate the Indemnitee for such loss.

9. Insurance.

9.1 Required Insurance. The Manager shall carry and maintain, or cause to be carried and maintained, for the benefit of and on behalf of Pipeline and the Manager, with insurance companies and deductibles and retentions selected by the Manager (unless otherwise required by Pipeline), the insurance described below. The parties agree that they shall cooperate reasonably with one another in an effort to reduce insurance costs hereunder.

9.1.1 General and/or Excess Liability insurance with limits of not less than $10,000,000 per occurrence for bodily injury and property damage combined. Limits in excess of $10,000,000 will only be procured with Pipeline approval. This insurance will include coverage for personal injury, contractual liability, broad form property damage, independent contractors, products/completed operations, cross liability, explosion, collapse and underground hazards.

9.1.2 At all times during the operation of the facilities and covering all employees of the Manager, (a) Worker's Compensation insurance complying with the laws of the state(s) having jurisdiction over each employee, and (b) Employer's Liability insurance with limits of not less than $1,000,000 per accident. To the extent permitted by applicable law, the Manager may self-insure the Worker's Compensation and Employer's Liability Insurance required herein.

9.1.3 At all times during the operation of the facilities, Automobile Liability insurance with a combined single limit of $1,000,000 per occurrence for bodily injury and property damage, including coverage for all owned, non-owned and hired vehicles, covering all vehicles owned or used by or on behalf of the Manager.

9.1.4 Any other insurance deemed necessary or appropriate by the Manager.

9.2 Conditions. The following conditions shall apply to the foregoing insurance provisions:

9.2.1 For the insurance required in Sections 9.1.1 and 9.1.3 above, (a) Pipeline and the Manager will be additional insureds under the policies, (b) the affiliates of the Manager will be additional insureds with respect to Pipeline and the operation of the facilities, (c) the insurance will be primary for such additional insureds, and (d) the Manager will provide certificates of insurance upon request.

9.2.2 For the insurance required in Section 9.1.3 above, the policies will provide for a waiver of all rights of subrogation in favor of Pipeline, and the Manager and their respective affiliates.

9.2.3 For the insurance maintained pursuant to Sections 9.1.3 and 9.1.4 above, the Manager will provide a certificate of upon request.

9.2.4 For the insurance required in Section 9.1.4 above, Pipeline and the Manager and their affiliates will be additional insureds under the policies with respect to Pipeline and the operation of Pipeline. Such insurance will be primary for such additional insureds.

9.3 Reimbursement. The costs for premiums, deductibles and retentions for the insurance maintained by the Manager pursuant to this Management Services Agreement shall be reimbursable costs pursuant to Section 7.1.2 of this Management Services Agreement. In addition, in the event that the Manager self-insures the Workers' Compensation and/or Employer's Liability insurance required above, the Manager shall be reimbursed as provided in Section 3.09 of the Accounting Procedure.

10. Term and Termination.

10.1 Term. This Management Services Agreement shall be effective as of January 1, 2002 (the "Effective Date") and shall continue for a Term of thirty (30) years unless terminated sooner pursuant to Section 10.2 below.

10.2 Termination.

10.2.1 Continuing Default by Manager. Unless caused by an event of "force majeure" as defined in or pursuant to Pipeline's FERC Gas Tariff, if the Manager materially defaults in the performance of its obligations under this Management Services Agreement and such material default continues for a period of 45 days after notice thereof by Pipeline to the Manager, Pipeline may, by notice to the Manager, terminate this Management Services Agreement; provided, however, that no such termination shall occur if the Manager has initiated action to cure such material default but, despite its good faith efforts, has been unable to complete such cure within such 45 day period, and the Manager's actions to complete such cure continue in good faith beyond the end of the 45 day period until such cure is completed. If, during the 45 day period, an emergency or other situation requiring prompt action arises and the Manager is not reasonably responding in a prompt fashion, Pipeline shall have the right to take such remedial action as it deems appropriate, provided that Pipeline shall use all reasonable efforts to notify the Manager prior to the taking by Pipeline of such action.

10.2.2 Continuing Default by Pipeline. Unless caused by an event of "force majeure" as defined in or pursuant to Pipeline's FERC Gas Tariff, if Pipeline materially defaults in the performance of its obligations under this Management Services Agreement and such material default continues for a period of 45 days after notice thereof by the Manager to Pipeline, the Manager may, by notice to Pipeline, terminate this Management Services Agreement; provided, however, that no termination shall occur if Pipeline has initiated action to cure such material default but, despite its good faith efforts, has been unable to complete such cure within such 45 day period, and the actions of Pipeline to complete such cure continue in good faith beyond the end of the 45 day period until such cure is completed.

10.2.3 Additional Events of Termination. In addition to termination in accordance with Sections 10.2.1 and 10.2.2, this Management Services Agreement shall terminate if (a) Pipeline and the Manager mutually agree to terminate this Management Services Agreement, or (b) either party, upon six (6) months prior written notice to the other party, terminates this Management Services Agreement.

11. Rights upon Termination and Survival of Obligations.

11.1 Rights Upon Termination. Upon Pipeline's termination of this Management Services Agreement, ServiceCo shall deliver to Pipeline at Pipeline's principal place of business all records, documents, accounts, files and other materials of Pipeline or pertaining to Pipeline's business as Pipeline may reasonably request, provided that ServiceCo may retain copies of any such items delivered to Pipeline. Pipeline shall assume and become liable for any contracts or obligations that ServiceCo may have undertaken with third parties in connection with its obligations hereunder, and ServiceCo shall execute all documents and take all other reasonable steps requested by Pipeline which may be required to assign to and vest in Pipeline all rights, benefits, interests and titles in connection with such contracts or obligations.

11.2 Termination Payment. In the event of a termination of this Management Services Agreement pursuant to Section 10, ServiceCo shall be entitled, in addition to all other amounts due hereunder as of the date of termination, to a cancellation payment equal to all costs and expenses reasonably incurred by ServiceCo as a direct result of such termination, including all reasonable severance and relocation costs incurred with respect to third parties. Such amount shall be due and payable by Pipeline within fifteen (15) days of ServiceCo's submission of an invoice therefore.

11.3 Survival of Obligations. Expiration or termination of this Management Services Agreement shall not relieve any party hereto of liability that has accrued or arisen prior to the date of such expiration or termination. The obligations of confidentiality and indemnification set forth herein shall survive expiration or termination of this Management Services Agreement.

12. Law of the Contract and Dispute Resolution.

12.1 Law of the Contract. THIS MANAGEMENT SERVICES AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF DELAWARE, WITHOUT REGARD TO THE PRINCIPLES OF CONFLICTS OF LAWS.

12.2 Dispute Resolution. Resolution of any and all controversies, disputes or claims, arising out of, relating to, in connection with or resulting from this Agreement (or any written amendment hereto or any transaction contemplated hereby), including as to its interpretation, performance, non-performance, validity, breach or termination, including any claim based on contract, tort, regulation, rule, statute or constitution and any claim raising questions of law, whether arising before or after termination of this Agreement (collectively, "Disputes"), shall be exclusively governed by and settled in accordance with the provisions of this Section 12. Unless otherwise agreed in writing, the parties will continue to honor their obligations not subject to Dispute under this Management Services Agreement during the course of dispute resolution pursuant to the provisions of this Section 12 with respect to all matters not subject to such dispute, controversy or claim.

12.3 Negotiation. The parties shall make a good faith attempt to resolve any Dispute through negotiation. Within thirty (30) days after notice of a Dispute is given by one party to another party or parties, each such party shall select one or more representatives of such party, which representatives shall meet and make a good faith attempt to resolve such Dispute and shall continue to negotiate in good faith in an effort to resolve the Dispute. If a settlement is mutually agreed upon as a result of the negotiation, then such settlement shall be recorded in writing, signed by the affected parties, and shall be binding on them. If such representatives fail to resolve a Dispute within thirty (30) days after the first meeting of the representatives, such Dispute shall be referred to the chief executive officers of the applicable parties for resolution. During the course of negotiations under this Section 12.3, all reasonable requests made by one party to any other party for information, including requests for copies of relevant documents, shall be promptly honored. The requesting party shall compensate the providing party for the reasonable costs, if any, of creating, gathering and copying such requested information. The specific format for such negotiations shall be left to the discretion of the designated representatives but may include the preparation of agreed upon statements of fact or written statements of position furnished by a party to another party or parties.

12.4 Alternative Dispute Resolution.

a. Alternative Dispute Resolution. In the event that any Dispute is not settled by the parties within fifteen (15) days after the first meeting of the chief executive officers under Section 12.3, the parties may attempt to resolve such Dispute by mediation and/or arbitration and in accordance with the terms and conditions (including allocation costs and expenses) established by the parties. If the parties elect to mediate the Dispute, once mediation has commenced, no litigation for the resolution of such Dispute may be commenced until the parties have completed in good faith the mediation. If a settlement is mutually agreed upon as a result of the mediation, then such settlement shall be recorded in writing, signed by the parties, and shall be binding on them and their respective successors and assigns. If the Parties elect to arbitrate the Dispute (either in lieu of or after mediation), the parties shall be deemed to have waived their right to litigate such Dispute in court and may not commence a court action pursuant to Section 12.4(b) of this Agreement. Any arbitration shall be governed by the Commercial Arbitration Rules of the American Arbitration Association.

b. Court Actions. In the event that a party, after complying with the provisions set forth in Section 12.3 and, if applicable, the mediation provisions of Section 12.4(a), desires to commence a court action, suit or other proceeding (an "Action") in respect to a Dispute, such party may, subject to the other provisions of this Management Services Agreement, submit the Dispute to any court of competent jurisdiction. If there is any court Action between any parties pursuant to this Section 12.4(b), the unsuccessful party to such court Action shall pay the prevailing party all costs and expenses, including reasonable attorneys' fees and disbursements, incurred by such prevailing party in such court Action and in any appeal in connection therewith. If such prevailing party recovers a judgment in any such court Action or appeal, such costs, expenses and attorneys' fees and disbursements shall be included in and as part of such judgment.

c. Specific Performance. Notwithstanding Sections 12.2 and 12.3 and paragraphs (a) and (b) of this Section 12.4, Manager and Pipeline agree that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms or were otherwise breached. It is accordingly agreed that Manager and Pipeline shall be entitled to injunctive relief to prevent breaches of this Agreement and to enforce specifically the terms and provisions hereof.

13. Special and Consequential Damages. Except as provided in Section 8 of this Management Services Agreement, neither party shall have any liability hereunder to the other party for any special, indirect, consequential or punitive damages.

14. Manager's Obligations Not Exclusive. The Parties agree that Manager's obligations under this Agreement are not exclusive, and nothing in this Agreement shall be deemed to limit Manager's right to offer or provide management services to any other entity (a "Third-Party Customer").

15. General.

15.1 Effect of Agreement; Amendments. This Management Services Agreement reflects the whole and entire agreement between the parties with respect to the subject matter hereof and supersedes all prior agreements and understandings, oral and written, between the parties with respect to the subject matter hereof. This Management Services Agreement can be amended, restated or supplemented only by the written agreement of the Manager and Pipeline.

15.2 Notices. Unless otherwise specifically provided in this Management Services Agreement, any notice or other communication shall be in writing and may be sent by (a) personal delivery (including delivery by a courier service), (b) telecopy to the following telecopy numbers (until changed in accordance with this Section 15.2) or (c) registered or certified mail, postage prepaid, addressed as set forth below (or at such other address as may be designated in accordance with this Section 15.2):

If to the Manager:

PG&E Gas Transmission Service Company, LLC
1400 SW Fifth Avenue, Suite 900
Portland, OR 97201
Attention: Robert T. Howard
Telecopy number: 503-833-4927

If to Pipeline:

North Baja Pipeline LLC
1400 SW Fifth Avenue, Suite 900
Portland, OR 97201
Attention: Legal Department
Telecopy number: 503-402-4004

Notices shall be deemed given upon receipt. Either party may change its address and/or telephone numbers for notice purposes by providing notice of such change to the other party.

15.3 Counterparts. This Management Services Agreement may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

15.4 Waiver. No waiver by either party of any default by the other party in the performance of any provision, condition or requirement herein shall be deemed to be a waiver of, or in any manner release the other party from, performance of any other provision, condition or requirement herein, nor shall such waiver be deemed to be a waiver of, or in any manner a release of, the other party from future performance of the same provision, condition or requirement. Any delay or omission of either party to exercise any right hereunder shall not impair the exercise of any such right, or any like right, accruing to it hereafter.

15.5 Assignability; Successors. This Management Services Agreement, and the rights, duties, and obligations hereunder, may not be assigned or delegated by either party without the written consent of the other party, except with respect to delegation by either party of all or a portion of its rights and obligations hereunder to its affiliates so long as such party remains responsible for all obligations (including any liability resulting from any defaults) of said affiliates; provided, however, that such consent shall not be unreasonably delayed or withheld. This Management Services Agreement and all of the obligations and rights herein established shall extend to and be binding upon and shall inure to the benefit of the respective successors and permitted assigns of the respective parties hereto. Unless consent to the assignment has been obtained, any assignment of this Management Services Agreement shall not relieve the assigning party of any of its obligations hereunder.

15.6 Third Persons. Except as otherwise provided in this Management Services Agreement nothing herein expressed or implied is intended or shall be construed to confer upon or to give any person not a party hereto any rights, remedies or obligations under or by reason of this Management Services Agreement.

15.7 Laws and Regulatory Bodies. This Management Services Agreement and the obligations of the parties hereunder are subject to all applicable laws, rules, orders and regulations of governmental authorities having jurisdiction, and to the extent of conflict, such laws, rules, orders and regulation of governmental authorities having jurisdiction shall control.

15.8 Section Numbers; Headings. Unless otherwise indicated, references to Section numbers are to Sections of this Management Services Agreement. Headings and captions are for reference purposes only and shall not affect the meaning or interpretation of this Management Services Agreement.

15.9 Severability. Any provision of this Management Services Agreement that is prohibited or unenforceable in any jurisdiction shall, as to that jurisdiction, be ineffective to the extent of that prohibition or unenforceability without invalidating the remaining provisions hereof or affecting the validity or enforceability of that provision in any other jurisdiction.

15.10 Further Assurances. Each party agrees to execute and deliver all such other and additional instruments and documents and to do such other acts and things as may be reasonably necessary more fully to effectuate the terms and provisions of this Management Services Agreement.

IN WITNESS WHEREOF, the parties have caused this Management Services Agreement to be executed by their duly authorized representatives as of the date first above written.

MANAGER:

PG&E Gas Transmission Services Company, LLC

By: /s/ Robert T. Howard
Name: Robert T. Howard
Title: Vice President

PIPELINE:

North Baja Pipeline LLC

By: /s/ Peter G. Lund
Name: Peter G. Lund
Title: Vice President

EXHIBIT A
TO
MANAGEMENT SERVICES AGREEMENT

ACCOUNTING PROCEDURE

ARTICLE I

General Provisions

1.01 Statements and Billings. The Manager shall bill Pipeline on or before the tenth (10th) Day of each Month or as soon as reasonably possible thereafter for the costs and expenses for the prior Month, including any adjustment that may be necessary to correct prior billings. Bills will be summarized by appropriate classifications indicative of the nature thereof and will be accompanied by such detail and supporting documentation as Pipeline may reasonably request.

1.02 Payment by Pipeline. Pipeline shall pay all bills presented by the Manager as provided in this Management Services Agreement on or before the fifteenth (15th) Day after the bill is received. If payment is not made within such time, the unpaid balance shall bear interest until paid at a rate (which shall in no event be higher than the maximum rate permitted by applicable law) equal to two percent (2%) per annum over the prime rate of Citibank, N.A. (or its successor) from time to time publicly announced and in effect. Payment by or on behalf of Pipeline shall not be deemed a waiver of the right to recoup any amount in question

1.03 Financial Records. The Manager shall maintain accurate books and records in accordance with FERC and FASB accounting procedures covering all of the Manager's actions under this Management Services Agreement.

ARTICLE II

Capital Items, Non-Capital Items, and Contribution of Inventory and Facilities

2.01 Capital Items

2.01.01 Definition of Capital Items. The term "Capital Items" as used herein shall mean any item of real and/or personal property that, if owned by and utilized for a FERC-regulated interstate pipeline company, would qualify for treatment as a capital expense under standard FERC accounting practices.

2.01.02 Certain Capital Items Owned by Manager. To the extent the Manager or any of its affiliates own any Capital Items necessary or desirable for the operation of the Pipeline ("Manager's Capital Items"), that Manager or such affiliates in its sole discretion (subject to Section 2.01.03 below) is willing to transfer for consideration to Pipeline, the Manager or such affiliates may, if approved by Pipeline, transfer such property to Pipeline. In the event of such a transfer, the Manager may charge Pipeline the net book value thereof (as reflected on the books of the Manager or such affiliates on the date of transfer). To the extent the Manager or any of its affiliates own Manager's Capital Items, and the Manager or such affiliates in its sole discretion chooses not to transfer such property to Pipeline, Manager may include as part of its costs to be reimbursed by Pipeline carrying costs and overhead expense related to such property, provided, however, Manager shall not charge carrying costs and overhead expense related to such property above the total costs (including return on equity) to which Pipeline would be entitled to collect from ratepayers if such property were owned by Pipeline.

2.01.03 Purchase of Additional Capital Items. Capital Items intended for the sole use of Pipeline shall be purchased by Manager on behalf of Pipeline and be owned by Pipeline. Capital Items intended to be utilized by Manager on behalf of Pipeline as well as Third-Party Customers (as defined in the Management Services Agreement) shall, at Manager's descretion, (i) be owned by Manager, subject to reimbursement by Pipeline of an allocated share of purchase costs, including carrying costs and overhead expense, as specified in Section 2.01.02 above or (ii) be owned by Pipeline in proportionate share with Third Party Customers.

2.02 Non-Capital Items

2.02.01 Contribution by Pipeline. Pipeline owns or holds rights to certain non-capital inventory and assets, such as office equipment and office space ("Expense Items"), that Manager may desire to use from time to time in providing service to Pipeline and/or Manager's other activities. Manager shall credit Pipeline for utilization of such Expense Items at fair market value.

ARTICLE III

Costs and Expenses

Subject to the limitations hereafter prescribed and provisions of this Management Services Agreement, the Manager shall charge Pipeline for all reasonable costs and expenses in providing services to Pipeline under this Management Services Agreement, including, but not limited to, the following items, to the extent reasonable and actually incurred or allocated to Pipeline:

3.01 Rentals. All rentals paid by the Manager.

3.02 Labor Costs.

3.02.01 Salaries and wages of employees of the Manager and its affiliates engaged in connection with the management of Pipeline and, in addition, amounts paid as salaries and wages of others temporarily employed in connection therewith. Such salaries and wages shall be loaded to include the Manager's actual costs of bonuses, holiday, vacation, sickness and jury service benefits and other customary allowances for time not worked paid to persons whose salaries and wages are chargeable under this Section 3.02.01.

3.02.02 Expenditures or contributions made pursuant to assessments imposed by Governmental Authority that are applicable to salaries, wages and costs chargeable under Section 3.02.01 above, including, but not limited to, FICA taxes and federal and state unemployment taxes. Such costs shall be charged on the basis of a percentage assessment on the amount of salaries and wages chargeable under Section 3.02.01 above or on an actual cost basis.

3.02.03 The costs of plans incurred by or on behalf of the Manager for workers' compensation, employers' group life insurance, hospitalization, disability, pension, retirement, savings and other benefit plans, that are applicable to salaries and wages chargeable under Section 3.02.01 above. Such costs shall be charged on the basis of a percentage assessment on the amount of salaries and wages chargeable under Section 3.02.01 above, or on an actual cost basis.

3.03 Programming and Information Processing. All costs incurred relating to programming and information processing actually and reasonably incurred or allocated on behalf of Pipeline in compliance with, and in furtherance of, the terms of this Management Services Agreement.

3.04 Reimbursable Expenses of Employees. Reasonable personal expenses of employees whose salaries and wages are chargeable under Section 3.02.01 above. As used herein, the term "personal expenses" shall mean out-of-pocket expenditures incurred by employees in the performance of their duties and for which such employees are reimbursed. The Manager shall maintain documentation for such expenses in accordance with the standards of the Internal Revenue Service.

3.05 Transportation. Transportation of employees, equipment and material and supplies necessary for management of the Pipeline.

3.06 Services. The cost of contract services and utilities procured from outside sources.

3.07 Legal Expenses and Claims. All costs and expenses of handling, investigating and settling litigation or claims arising by reason of the management of Pipeline or necessary to protect or recover any assets or property, including, but not limited to, attorneys' fees, court costs, costs of investigation or procuring evidence and any judgments paid or amounts paid in settlement or satisfaction of any such litigation or claims. All judgments received or amounts received in settlement of litigation with respect to any claim asserted on behalf of Pipeline shall be for the benefit of and shall be remitted to Pipeline.

3.08 Taxes. All taxes (except those measured by income) of every kind and nature assessed or levied upon or incurred in connection with the management of Pipeline or on Pipeline's facilities or other property of Pipeline and which taxes have been paid by the Manager for the benefit of Pipeline, including charges for late payment arising from extensions of the time for filing that are caused by Pipeline, or that result from the Manager's good faith efforts to contest the amount of application of any tax.

3.09 Insurance. Net of any returns, refunds or dividends, all premiums, deductibles and retentions paid and expenses incurred for insurance required to be carried under the Management Services Agreement. In the event that the Manager self-insures any of the insurance required or permitted under this Management Services Agreement, the Manager shall be reimbursed only for the amount equivalent to the standard premium(s) which would have been paid had such insurance been acquired, and the Manager shall not be reimbursed for the costs associated with any claims paid by the Manager as an insurer under such self-insurance.

3.10 Permits, Licenses and Bond. Cost of permits, licenses and bond premiums necessary in the performance of the Manager's duties on behalf of Pipeline as herein contemplated.

3.12 Administrative and General and Overhead Costs. Administrative and general and overhead costs, including salaries and wages, bonuses and expenses of personnel of the Manager and/or the Manager's affiliates (excluding the personnel referred to in Section 3.02 of this Article III) who render services for the benefit of the Manager (in the performance of its obligations hereunder) or Pipeline, office supplies and expenses, office rentals and other space costs, less the value of such costs made available to Manager by Pipeline

3.11 Changes in Cost Determination and Allocation. The Manager may request a change in the cost components or the determination of the cost components set forth in this Exhibit A. Any requested change in a cost component or in the determination of a cost component must be reviewed and approved by Pipeline prior to the implementation of such change by the Manager.

End of Exhibit A

Exhibit 31.1

CERTIFICATION

I, Russell K. Girling, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: August 4, 2009

/s/ Russell K. Girling
Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Amy W. Leong, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: August 4, 2009

/s/ Amy W. Leong
Amy W. Leong
Controller
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Financial Officer)

Exhibit 32.1

CERTIFICATION

I, Russell K. Girling, Chief Executive Officer of TC PipeLines GP, Inc., the general partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge**,** in connection with the Partnership's Quarterly Report on Form 10-Q for the period ended June 30, 2009 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: August 4, 2009

/s/ Russell K. Girling
Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Executive Officer)

Exhibit 32.2

CERTIFICATION

I, Amy W. Leong, Principal Financial Officer of TC PipeLines GP, Inc., the general partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Quarterly Report on Form 10-Q for the period ended June 30, 2009 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: August 4, 2009

/s/ Amy W. Leong
Amy W. Leong
Controller
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Financial Officer)