Dynagas LNG Partners LP
Form 6-K
November 20, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER PURSUANT TO RULE 13A-16 OR 15D-16 OF THE SECURITIES EXCHANGE ACT OF 1934

For the month of November 2018

Commission File Number: 001-36185

Dynagas LNG Partners LP
(Translation of registrant's name into English)

23, Rue Basse

98000 Monaco
(Address of principal executive office)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F [X]   Form 40-F [ ]

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): [ ].

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): [ ].

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

INFORMATION CONTAINED IN THIS FORM 6-K REPORT

Attached as Exhibit 99.1 to this Report on Form 6-K is a copy of the press release of Dynagas LNG Partners LP (the Partnership) dated November 15, 2018: DYNAGAS LNG PARTNERS LP REPORTS RESULTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2018.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: November 20, 2018

DYNAGAS LNG PARTNERS LP

By:	/s/ Tony Lauritzen
Name:	Tony Lauritzen
Title:	Chief Executive Officer

DYNAGAS LNG PARTNERS LP REPORTS RESULTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2018

MONACO November 15, 2018 - Dynagas LNG Partners LP (NYSE: DLNG) (Dynagas Partners or the Partnership an owner and operator of liquefied natural gas (LNG) carriers, today announced its results for the three and nine months ended September 30, 2018.

Quarter Highlights:

- Net loss of $0.7 million for the three months ended September 30, 2018. Included in the third quarter 2018 results are $2.3 million of scheduled class survey and dry-docking costs related to the *Yenisei River*, one of the three tri-fuel diesel engine (TFDE) vessels in our fleet;
- Loss per common unit of $0.07 for the three months ended September 30, 2018;
- Adjusted Net Income[(1)] of $3.3 million for the three months ended September 30, 2018;
- Adjusted Earnings per common unit [(1)] [(2)] of $0.04 for the three months ended September 30, 2018;
- Distributable Cash Flow[(1)] of $7.5 million during the three months ended September 30, 2018 ;
- Adjusted EBITDA[(1)] of $23.5 million for the three months ended September 30, 2018;
- Reported free cash of $59.5 million and available liquidity of $89.5 million as of September 30, 2018;
-

The *Yenisei River* completed its scheduled dry-docking and special survey and subsequently entered earlier than anticipated into its multi-year charter with Yamal Trade Pte. (Yamal) which was extended from 15 years to 15 years and 180 days.

Subsequent Highlights:

- Completed a $55.0 million underwritten public offering of 2.2 million 8.75% Fixed to Floating Cumulative Redeemable Perpetual Preferred Units (the Series B Preferred Units);

- Declared quarterly cash distribution of $0.25 per common unit in respect of the third quarter of 2018 and $0.5625 per preferred unit in respect of the most recent period.

- The *Lena River* completed its scheduled dry-docking and special survey in late October 2018 and subsequently delivered into a multi-month charter with a major energy company, prior to its anticipated delivery to its multi-year charter with Yamal.

(1) Adjusted Net Income, Adjusted Earnings per common unit, Distributable Cash Flow and Adjusted EBITDA are not recognized measures under U.S. GAAP. Please refer to Appendix B of this press release for the definitions and reconciliation of these measures to the most directly comparable financial measures calculated and presented in accordance with U.S. GAAP and other related information.

(2) Adjusted Earnings per common unit presentation excludes the Series A Preferred Units interest on the Partnership s net income for the periods presented.

Recent Developments:

Quarterly common unit cash distribution: On October 11, 2018, the Partnership announced a quarterly cash distribution of $0.25 per common unit in respect of the third quarter of 2018 which was paid on October 26, 2018 to all common unitholders of record as of October 19, 2018.

Series A Preferred Units cash distribution: On October 24, 2018, the Partnership announced a cash distribution of $0.5625 per unit of its Series A Preferred Units (NYSE: DLNG PR A) for the period from August 12, 2018 to November 11, 2018, which was paid on November 12, 2018 to all unitholders of record as of November 5, 2018.

Yenisei River early commencement of multi-year charter with Yamal: On August 14, 2018, immediately upon completion of its mandatory statutory class five-year special survey and dry-docking, the *Yenisei River* was delivered earlier than anticipated to its multi-year charter contract with Yamal in order to serve the Yamal LNG project, pursuant to an agreement with Yamal according to which the firm charter period was extended from 15 years to 15 years plus 180 days. The initial term of the charter may be extended by three consecutive periods of five years.

Series B Preferred Units public offering: On October 23, 2018, the Partnership completed an underwritten public offering of 2,200,000 Series B Preferred Units, representing limited partner interests in the Partnership, at a price of $25.00 per unit. Distributions will be payable on the Series B Preferred Units up to November 22, 2023 at a fixed rate equal to 8.75% per annum and from November 22, 2023, if not redeemed, at a floating rate. The Partnership has granted the underwriters a 30-day option to purchase up to an additional 330,000 Series B Preferred Units on the same terms and conditions. The Partnership received net proceeds of $53.0 million, after deducting underwriters discounts and commissions and estimated offering expenses and intends to use the net proceeds from the public offering for general Partnership purposes, which may include, among other things, the repayment of indebtedness, including the Partnership s outstanding 6.25% Senior Notes due on October 30, 2019, or the funding of acquisitions or other capital expenditures.

CEO Commentary:

Tony Lauritzen, Chief Executive Officer of the Partnership, commented:

We are pleased to report our earnings for the three months ended September 30, 2018.

Our reported earnings for the third quarter of 2018 were in line with our expectations. Compared to the same period in 2017, our third quarter earnings were impacted by the following occurrences: (i) two of our vessels, the *Arctic Aurora* and the *Ob River*, commenced employment under extended charter contracts with their respective charterers at lower rates compared with the previous charter contracts, and (ii) the special survey and dry-docking of the *Yenisei River*.

Based on our contracted revenue backlog estimate, we have a high level of visibility and predictability in our future cash flow generating capacity, given that all of our LNG carriers are employed on long- term contracts with an average contract duration of approximately ten years, with the first potential vessel availability in the year 2021 (with only one vessel) and thereafter in the year 2026. We believe that our best in class contracted revenue backlog estimate of $1.4bn is driven in part by our dominant market share in the ownership and operation of ice class LNG carriers. Going forward we continue to remain focused on the safe and efficient operation of our unique and versatile fleet.

We are very pleased that the Yamal LNG project is progressing well. Immediately after the completion of its special survey, the *Yenisei River* commenced employment under a long-term contract with Yamal LNG on August 14, 2018, which was earlier than originally agreed in the charter contract and as a result the contract was extended by an additional 180 days to an aggregate term of 15 years and 180 days.

The *Lena River* is currently employed on a multi -month charter contract with a large US gas producer until the vessel commences employment under its 15 year contract with Yamal LNG, which is expected to commence in the second half of 2019.

We intend to refinance our $250 million unsecured notes due in October 2019. We are currently performing a review of all of our refinancing options taking into account, among other things, our financial and growth objectives.

Financial Results Overview:

(U.S. dollars in thousands, except per unit data)	Three Months Ended		Nine Months Ended	
	September 30, 2018 (unaudited)	**September 30, 2017** (unaudited)	**September 30, 2018** (unaudited)	**September 30, 2017** (unaudited)
Voyage revenues	$ 31,320	$ 33,471	$ 96,116	$ 104,538
Net Income/ (loss)	$ (654)	$ 3,983	$ 4,537	$ 11,714
Adjusted Net Income (1)	$ 3,275	$ 7,047	$ 15,033	$ 26,172
Operating income	$ 11,903	$ 15,893	$ 41,271	$ 46,520
Adjusted EBITDA(1)	$ 23,474	$ 26,434	$ 74,507	$ 80,626
Earnings/ (loss) per common unit	$ (0.07)	$ 0.06	$ (0.01)	$ 0.16
Adjusted Earnings per common unit (1)	$ 0.04	$ 0.15	$ 0.28	$ 0.57
Distributable Cash Flow (1)	$ 7,506	$ 11,295	$ 27,462	$ 38,129

(1) Adjusted Net Income, Adjusted EBITDA, Adjusted Earnings per common unit and Distributable Cash Flow are not recognized measures under U.S. GAAP. Please refer to Appendix B of this press release for the definitions and reconciliation of these measures to the most directly comparable financial measures calculated and presented in accordance with U.S. GAAP.

Three Months Ended September 30, 2018 and 2017 Financial Results

Net loss for the three months ended September 30, 2018 was $0.7 million as compared to net income of $4.0 million in the corresponding period of 2017, which represents a decrease of $4.7 million, or 116.4%. The decrease in period net income, as further discussed below, was mainly attributable to:

(i)

the decrease in period operating revenues during the three months ended September 30, 2018, as compared to the same period in 2017, as further elaborated below;

(ii)

costs associated with the *Yenisei River* dry-dock and special survey which occurred in the third quarter of 2018 (16.5 dry-dock days in the third quarter of 2018 versus 10 dry-dock days in the same period in 2017); and

(iii)

the increase in the weighted average interest of our $480 million Term Loan B in the third quarter of 2018 in comparison to the third quarter of 2017, which correspondingly increased the Partnership s interest and finance costs for the current period.

Adjusted Net Income for the three months ended September 30, 2018 was $3.3 million as compared to Adjusted Net Income of $7.0 million in the corresponding period of 2017, which represents a decrease of $3.8 million, or 53.5%. Adjusted EBITDA for the three months ended September 30, 2018 was $23.5 million as compared to Adjusted EBITDA of $26.4 million in the corresponding period of 2017, which represents a decrease of $3.0 million, or 11.2%. The decrease in both Adjusted Net Income and Adjusted EBITDA in the third quarter of 2018 as compared to the corresponding period of 2017 was predominantly attributable to the decrease in the voyage revenues, as further discussed below.

The Partnership s Distributable Cash Flow for the three-month period ended September 30, 2018 was $7.5 million as compared to $11.3 million in the corresponding period of 2017, which represents a decrease of $3.8 million, or 33.6%, and was due to factors (i) to (iii) outlined above.

For the three-month period ended September 30, 2018, the Partnership reported loss per common unit and Adjusted Earnings per common unit, basic and diluted, of $0.07 and $0.04, respectively, after taking into account the effect of the Series A Preferred Units interest on the Partnership s net loss/ Adjusted Net Income. Losses per common unit and Adjusted Earnings per common unit, basic and diluted are calculated on the basis of a weighted average number of 35,490,000 units outstanding during the period and, in the case of Adjusted Earnings per common unit, after reflecting the impact of the non-cash items presented in Appendix B of this press release.

Adjusted Net Income, Adjusted EBITDA, Distributable Cash Flow and Adjusted Earnings per common unit are not recognized measures under U.S. GAAP. Please refer to Appendix B of this press release for the definitions and reconciliation of these measures to the most directly comparable financial measures calculated and presented in accordance with U.S. GAAP.

Voyage revenues were $31.3 million for the three-month period ended September 30, 2018 as compared to $33.5 million for the same period of 2017, which represents a decrease of $2.2 million, or 6.4%. This decrease was mainly due to:

(i)

lower revenues earned on the Arctic Aurora, which, on August 2, 2018, rolled-over into a new charter with Equinor ASA (Equinor) (which was in direct continuation of its previous charter contract with Equinor) at a lower charter rate;

(ii)

lower revenues earned on the Ob River, which completed employment under its multiyear charter contract with Gazprom Global LNG Limited (Gazprom) in April 2018 and subsequently began employment under a ten-year charter party with an entity which is part of the wider Gazprom group of companies at a lower charter rate, and

(iii)

the 16.5 off-hire days of the Yenisei River, which had its scheduled special survey and dry-docking carried out in the third quarter of 2018 (after completion of its five year legacy charter with Gazprom).

This decrease was, however, partially offset by the increase in voyage revenues on our steam turbine vessel, the *Clean Energy*, which was delivered in accordance with its eight-year charter party with Gazprom in the third quarter of 2018, whereas, the vessel traded in the spot market in the same period of 2017 at lower charter rates.

Vessel operating expenses were $6.4 million, which corresponds to a daily rate of $11,632, for the three-month period ended September 30, 2018, as compared to $6.2 million, or a daily rate of $11,188, in the corresponding period of 2017. This increase was mainly derived from increased spares costs for our tri-fuel diesel engine vessel *Yenisei River*, which were incurred concurrently with the vessel s scheduled special survey and dry-docking.

Interest and finance costs were $12.8 million in the third quarter of 2018 as compared to $11.8 million in the third quarter of 2017, which represents an increase of $1.0 million, or 8.2%. As discussed above,

this increase was due to the increase in the Partnership s weighted average interest in the third quarter of 2018 (related to increased interest charges on our variable interest bearing secured debt).

The Partnership reported average daily hire gross of commissions [(1)] of approximately $59,800 per day per vessel in the three months ended September 30, 2018, as compared to approximately $65,200 per day per vessel in the same period of 2017. During the three-month period ended September 30, 2018, the Partnership s vessels operated at 99% utilization as compared to 97% utilization in the same period of 2017.

[(1)] Average daily hire gross of commissions , which is further discussed in Appendix B, represents voyage revenue without taking into consideration the non-cash time charter amortization expense and amortization of prepaid charter revenue, divided by the Available Days (as defined in Appendix B of this press release) in the Partnership s fleet

Amounts relating to variations in period on period comparisons shown in this section are derived from the condensed financial statements presented below.

Liquidity/ Financing/ Cash Flow Coverage

As of September 30, 2018, the Partnership reported free cash of $59.5 million. Total indebtedness outstanding as of September 30, 2018 was $724.0 million (gross of unamortized deferred loan fees), which includes amounts outstanding under the Term Loan B and the Partnership s $250.0 million senior unsecured notes due October 30, 2019. As of September 30, 2018, $4.8 million of the Partnership s outstanding indebtedness was repayable within one year.

The Partnership s liquidity profile is further supported by the $30.0 million of borrowing capacity under the Partnership s revolving credit facility with its Sponsor, which was extended on November 14, 2018, and is available to the Partnership at any time until November 2023. The $30 million sponsor facility remains available in its entirety as of the date of this release.

As of September 30, 2018, the Partnership reported working capital surplus of $40.2 million (Q4 2017: $47.5 million).

During the three months ended September 30, 2018, the Partnership generated net cash from operating activities of $13.5 million as compared to $14.8 million in the same period of 2017, which represents a decrease of $1.3 million, or 8.7%. This decrease was attributable to the decrease in net income during the three months ended September 30, 2018, as compared to the same period in 2017, due to the factors discussed above which were, however, counterbalanced by the positive effect of variations in working capital.

Vessel Employment

As of November 15, 2018, the Partnership had estimated contracted time charter coverage(2) for 100% of its fleet estimated Available Days for the rest of 2018, 99% of its fleet estimated Available Days for 2019 and 100% of its fleet estimated Available Days for 2020.

As of the same date, the Partnership s contracted revenue backlog estimate(3) was approximately $1.42 billion, with an average remaining contract term of 9.9 years.

(2) Time charter coverage for the Partnership s fleet is calculated by dividing the fleet contracted days on the basis of the earliest estimated delivery and redelivery dates prescribed in the Partnership s current time charter contracts net of scheduled class survey repairs by the number of expected Available days during that period.

(3) The Partnership calculates its estimated contracted revenue backlog by multiplying the contractual daily hire rate by the expected number of days committed under the contracts (assuming earliest delivery and redelivery and excluding options to extend), assuming full utilization. The actual amount of revenues earned and the actual periods during which revenues are earned may differ from the amounts and periods disclosed due to, for example, dry-docking and/or special survey downtime, maintenance projects, off-hire downtime and other factors that result in lower revenues than the Partnership s average contract backlog per day. Certain time charter contracts that the Partnership recently entered into with Yamal are subject to the satisfaction of important conditions (which includes, but are not limited to, a condition requiring that certain defaults have not occurred under two shipbuilding contracts held by special purpose companies that are affiliates of the Partnership but are not controlled by the Partnership, which, if not satisfied, or waived by the charterer, may result in their cancellation or amendment before or after the charter term commences and in such case the Partnership may not receive the contracted revenues thereunder.

Conference Call and Webcast: November 16, 2018

As announced, the Partnership s management team will host a conference call on Friday, November 16, 2018 at 10:00 a.m. Eastern Time to discuss the Partnership s financial results.

Conference Call details:

Participants should Participants should dial into the call 10 minutes before the scheduled time using the following numbers: 1 (877) 553-9962 (US Toll Free Dial In), 0(808) 238-0669 (UK Toll Free Dial In) or +44 (0) 2071 928592 (Standard International Dial In). Please quote "Dynagas."

A telephonic replay of the conference call will be available until Friday, November 23, 2018, by dialing 1(866) 331-1332 (US Toll Free Dial In), 0(808) 238-0667 (UK Toll Free Dial In) or +44 (0) 3333 009785 (Standard International Dial In) and the access code required for the replay is: 59711562#.

Audio Webcast - Slides Presentation:

There will be a live and then archived audio webcast of the conference call, via the internet through the Dynagas LNG Partners LP website www.dynagaspartners.com. Participants to the live webcast should register on the website approximately 10 minutes prior to the start of the webcast.

The slide presentation on the third quarter ended September 30, 2018 financial results will be available in PDF format 10 minutes prior to the conference call and webcast, accessible on the Company's website www.dynagaspartners.com on the webcast page. Participants to the webcast can download the PDF presentation.

About Dynagas LNG Partners LP

Dynagas LNG Partners LP (NYSE: DLNG) is a growth-oriented master limited partnership formed by Dynagas Holding Ltd., its sponsor, to own and operate liquefied natural gas (LNG) carriers employed on multi-year charters. The current fleet of Dynagas Partners consists of six LNG carriers, with an aggregate carrying capacity of approximately 914,000 cubic meters.

Visit the Partnership s website at www.dynagaspartners.com

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Forward-Looking Statement

Matters discussed in this press release may constitute forward-looking statements. The Private Securities Litigation Reform Act of 1995 provides safe harbor protections for forward-looking statements in order to encourage companies to provide prospective information about their business. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements, which are other than statements of historical facts.

The Partnership desires to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and is including this cautionary statement in connection with this safe harbor legislation. The words believe, anticipate, intends, estimate, forecast, project, plan, potential, may, should, expect, expected expressions identify forward-looking statements.

The forward-looking statements in this press release are based upon various assumptions, many of which are based, in turn, upon further assumptions, including without limitation, examination by the Partnership s management of historical operating trends, data contained in its records and other data available from third parties. Although the Partnership believes that these assumptions were reasonable when made, because these assumptions are inherently subject to significant uncertainties and contingencies which are difficult or impossible to predict and are beyond the Partnership s control, the Partnership cannot assure you that it will achieve or accomplish these expectations, beliefs or projections.

In addition to these important factors, other important factors that, in the Partnership s view, could cause actual results to differ materially from those discussed in the forward-looking statements include the strength of world economies and currencies, general market conditions, including fluctuations in charter rates and vessel values, changes in demand for LNG shipping capacity, changes in the Partnership s operating expenses, including bunker prices, drydocking and insurance costs, the market for the Partnership s vessels, availability of financing and refinancing, changes in governmental rules and regulations or actions taken by regulatory authorities, potential liability from pending or future litigation, general domestic and international political conditions, potential disruption of shipping routes due to accidents or political events, vessel breakdowns and instances of off-hires, the amount of cash available for distribution, and other factors. Please see the Partnership s filings and other reports furnished to the U.S. Securities and Exchange Commission for a more complete discussion of these and other risks and uncertainties. The information set forth herein speaks only as of the date hereof, and the Partnership disclaims any intention or obligation to update any forward-looking statements as a result of developments occurring after the date of this communication. Further, we cannot assess the effect of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to be materially different from those contained in any forward-looking statement.

APPENDIX A

DYNAGAS LNG PARTNERS LP

Unaudited Condensed Consolidated Statements of Income

(In thousands of U.S. dollars except for units and per unit data)	Three Months Ended September 30,				Nine Months Ended September 30,			
		2018		2017		2018		2017
REVENUES								
Voyage revenues	$	31,320	$	33,471	$	96,116	$	104,538
EXPENSES								

Voyage expenses (including related party)		(930)		(717)		(2,173)		(2,934)
Vessel operating expenses		(6,421)		(6,176)		(18,662)		(20,337)
Dry-docking and special survey costs		(2,346)		(1,096)		(5,042)		(6,227)
General and administrative expenses (including related party)		(475)		(394)		(1,537)		(1,234)
Management fees -related party		(1,600)		(1,553)		(4,747)		(4,609)
Depreciation		(7,645)		(7,642)		(22,684)		(22,677)
Operating income		**11,903**		**15,893**		**41,271**		**46,520**
Interest and finance costs, net		(12,554)		(11,745)		(36,790)		(34,360)
Other, net		(3)		(165)		56		(446)
Net (loss)/income	**$**	**(654)**	**$**	**3,983**	**$**	**4,537**	**$**	**11,714**
(Loss)/ Earnings per common unit (basic and diluted)	**$**	**(0.07)**	**$**	**0.06**	**$**	**(0.01)**	**$**	**0.16**
Weighted average number of units outstanding, basic and diluted:								
Common units		35,490,000		35,490,000		35,490,000		34,227,527

DYNAGAS LNG PARTNERS LP

Consolidated Condensed Balance Sheets (unaudited)

(Expressed in thousands of U.S. Dollars except for unit data)

	September 30, 2018	December 31, 2017

ASSETS				
CURRENT ASSETS:				
Cash and cash equivalents	$	59,536	$	67,464
Due from related party		1,117		883
Other current assets		2,870		2,057
Total current assets		**63,523**		**70,404**
FIXED ASSETS, NET:				
Vessels, net		955,022		977,298
Total fixed assets, net		**955,022**		**977,298**
OTHER NON CURRENT ASSETS:				
Due from related party		1,350		1,350
Deferred charges		1,918		
Accrued charter revenue		135		
Above market acquired time charters				5,267
Total assets	**$**	**1,021,948**	**$**	**1,054,319**
LIABILITIES AND PARTNERS EQUITY				
CURRENT LIABILITIES:				
Current portion of long-term debt, net of deferred financing costs	**$**	2,678	**$**	2,655
Trade payables		6,313		4,497
Due to related party		116		72
Accrued liabilities		5,107		4,051
Unearned revenue		9,071		11,623
Total current liabilities		**23,285**		**22,898**
Deferred revenue		3,140		1,405
Long-term debt, net of current portion and deferred financing costs		710,521		711,698
Total non-current liabilities		**713,661**		**713,103**
PARTNERS EQUITY				
General partner (35,526 units issued and outstanding as at September 30, 2018 and December 31, 2017)		(3)		47
Common unitholders (35,490,000 units issued and outstanding as at September 30, 2018 and December 31, 2017)		211,789		245,055
Series A Preferred unitholders: (3,000,000 units issued and outstanding as at September 30, 2018 and December 31, 2017)		73,216		73,216
Total partners equity		**285,002**		**318,318**
Total liabilities and partners equity	**$**	**1,021,948**	**$**	**1,054,319**

DYNAGAS LNG PARTNERS LP

Consolidated Statements of Cash Flows

(Expressed in thousands of U.S. Dollars)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Cash flows from Operating Activities:				
Net (loss)/ income:	$ (654)	$ 3,983	$ 4,537	$ 11,714
Adjustments to reconcile net income/ (loss) to net cash provided by operating activities:				
Depreciation	7,645	7,642	22,684	22,677
Amortization and write-off of deferred financing fees	819	839	2,444	4,562
Amortization of fair value of acquired time charter	1,673	1,826	5,267	5,420
Deferred revenue amortization	(121)	142	156	228
Deferred charges amortization	31		31	
Changes in operating assets and liabilities:				
Trade receivables	(6)	(27)	87	(223)
Prepayments and other assets	645	370	141	(508)
Inventories	2,028	(1,319)	(1,041)	(1,256)
Due from/ to related parties	1,267	309	(190)	346
Deferred charges	307		(505)	
Trade payables	(2,745)	(1,991)	1,865	4,083
Accrued liabilities	393	(1,765)	1,056	(75)
Unearned revenue	2,204	4,756	(2,552)	(2,635)
Net cash from Operating Activities	**13,486**	**14,765**	**33,980**	**44,333**
Cash flows from Investing Activities				
Other additions to vessels	1		(408)	

equipment				
Net cash used in Investing Activities	1	**(408)**		
Cash flows from Financing Activities:				
Net income	27.4	33.0	81.2	93.9
Other comprehensive income/(loss)				
Change associated with hedging transactions (Note 9)	(0.1)	(1.3)	6.3	(1.7)
Change associated with hedging transactions of investees	0.9	-	1.1	(0.7)
	0.8	(1.3)	7.4	(2.4)
Total comprehensive income	28.2	31.7	88.6	91.5

(a) Recast as discussed in Note 1 and Note 4.

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

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TC PipeLines, LP
Consolidated Balance Sheet

(unaudited) (millions of dollars)	September 30, 2009	December 31, 2008(a)
ASSETS		
Current Assets		
Cash and cash equivalents	5.2	8.4
Accounts receivable and other	6.8	11.4
	12.0	19.8
Investment in Great Lakes (Note 2)	696.2	704.5
Investment in Northern Border (Note 3)	531.2	514.8
Plant, property and equipment (net of $110.2 accumulated depreciation, 2008 - $103.6)	321.4	330.3
Goodwill	130.2	130.2
Other assets	1.2	1.5
	1,692.2	1,701.1
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable	4.3	5.3
Accrued interest	2.4	3.7
Current portion of long-term debt (Note 5)	4.4	4.4
Current portion of fair value of derivative contracts (Note 9)	12.1	11.8
	23.2	25.2
Fair value of derivative contracts and other (Note 9)	14.0	20.4
Long-term debt (Note 5)	733.1	532.4
	770.3	578.0
Due to North Baja's former parent	-	247.5
Partners' Equity		
Common units	929.5	891.4
General partner	19.9	19.1
Accumulated other comprehensive loss	(27.5)	(34.9)
	921.9	875.6
	1,692.2	1,701.1

(a) Recast as discussed in Note 1 and Note 4.

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)	Nine months ended September 30, 2009(a)	2008(a)
CASH GENERATED FROM OPERATIONS		
Net income	81.2	93.9
Depreciation	11.0	10.2
Amortization of other assets	0.3	0.4
Increase in long-term liabilities	0.2	0.1
Equity allowance for funds used during construction	(0.1)	(1.0)
Increase/(decrease) in operating working capital (Note 10)	2.3	(3.3)
	94.9	100.3
INVESTING ACTIVITIES		
Cumulative distributions in excess of equity earnings:		
Great Lakes	8.4	10.6
Northern Border	27.0	23.9
Investment in Great Lakes	(0.1)	-
Investment in Northern Border (Note 3)	(42.3)	-
Investment in North Baja, net of cash acquired (Note 4)	(271.3)	-
Capital expenditures	(2.1)	(31.8)
Increase in investing working capital (Note 10)	-	(2.8)
	(280.4)	(0.1)
FINANCING ACTIVITIES		
Distributions paid (Note 7)	(86.3)	(80.8)
Equity issuances, net	80.0	-
Long-term debt issued (Note 5)	208.0	4.0
Long-term debt repaid (Note 5)	(7.3)	(31.3)
Due to North Baja's former parent	(12.1)	11.4
	182.3	(96.7)
(Decrease)/increase in cash and cash equivalents	(3.2)	3.5
Cash and cash equivalents, beginning of period	8.4	7.5
Cash and cash equivalents, end of period	5.2	11.0
Interest payments made	13.2	22.8

(a) Recast as discussed in Note 1 and Note 4.

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(a)	Partners' Equity	
	(millions of units)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of units)	(millions of dollars)
Partners' equity at December 31, 2008	34.9	891.4	19.1	(34.9)	34.9	875.6
Net income(b)	-	74.3	6.9	-	-	81.2
Equity issuance	6.3	78.4	1.6	-	6.3	80.0
Distributions paid	-	(79.3)	(7.0)	-	-	(86.3)
Excess purchase price over net acquired assets(c)	-	(35.3)	(0.7)	-	-	(36.0)
Other comprehensive income	-	-	-	7.4	-	7.4
Partners' equity at September 30, 2009	41.2	929.5	19.9	(27.5)	41.2	921.9

(a) TC PipeLines, LP uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at September 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 $12.1 million, which will be offset by a reduction to interest expense of a similar amount.

(b) Recast as discussed in Note 1 and Note 4.

(c) Accounting adjustment for common control transaction. See Note 4 for details.

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

TC PipeLines, LP
Notes to Consolidated Financial Statements

Note 1 Organization 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 nine months ended September 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.

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja Pipeline, LLC (North Baja) from a wholly-owned subsidiary of TransCanada Corporation. TransCanada Corporation and its subsidiaries are herein collectively referred to as “TransCanada”. Because North Baja was acquired from TransCanada, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada’s carrying value and the Partnership’s historical financial information was recast to include the acquired entity for all periods presented. Refer to Note 4 for additional disclosure regarding the North Baja acquisition.

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 TransCanada.

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

The following tables contain summarized financial information of Great Lakes:

Summarized Consolidated Great Lakes Income Statement (unaudited) (millions of dollars)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Transmission revenues	68.9	66.7	220.4	213.9
Operating expenses	(16.5)	(17.1)	(49.6)	(45.9)
Depreciation	(14.7)	(14.7)	(43.9)	(43.9)
Financial charges, net and other	(8.1)	(8.0)	(24.4)	(24.4)

Michigan business tax	(1.3)	(1.2)	(4.4)	(4.2)
Net income	28.3	25.7	98.1	95.5

Summarized Consolidated Great Lakes Balance Sheet

(unaudited) (millions of dollars)	September 30, 2009	December 31, 2008
Assets		
Cash and cash equivalents	-	1.6
Other current assets	90.1	80.2
Plant, property and equipment, net	884.6	923.4
	974.7	1,005.2
Liabilities and Partners' Equity		
Current liabilities	38.4	43.0
Deferred credits	3.4	2.3
Long-term debt, including current maturities	421.0	430.0
Partners' capital	511.9	529.9
	974.7	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 the 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 nine months ended September 30, 2009 and 2008.

Northern Border received equity contributions totaling $84.6 million during the nine months ended September 30, 2009 to complete the Des Plaines project and to partially fund $200.0 million of debt which matured on September 1, 2009. The Partnership’s share of this equity contribution was $42.3 million.

The following tables contain summarized financial information of Northern Border:

Summarized Northern Border Income Statement (unaudited) (millions of dollars)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Transmission revenues	65.2	67.7	193.9	212.8
Operating expenses	(19.0)	(19.3)	(55.8)	(57.5)
Depreciation	(15.6)	(15.3)	(46.4)	(45.8)
Financial charges, net and other	(9.1)	7.1	(27.4)	(12.1)
Net income	21.5	40.2	64.3	97.4

Summarized Northern Border Balance Sheet (unaudited) (millions of dollars)	September 30, 2009	December 31, 2008
Assets		
Cash and cash equivalents	18.4	21.6
Other current assets	28.5	39.1
Plant, property and equipment, net	1,356.4	1,390.8
Other assets	25.5	24.5
	1,428.8	1,476.0
Liabilities and Partners' Equity		
Current liabilities	42.7	48.7
Deferred credits and other	8.0	11.2
Long-term debt, including current maturities	558.5	630.4
Partners' equity		
Partners' capital	823.1	791.4
Accumulated other comprehensive loss	(3.5)	(5.7)
	1,428.8	1,476.0

Note 4 Acquisition & Revised Incentive Distribution Rights

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

The initial purchase price of $271.3 million was financed through a combination of (i) a draw of $170.0 million on the Partnership’s $250.0 million revolving portion of its revolving credit and term loan agreement (Senior Credit Facility), (ii) issuance of 2,609,680 common units at $30.042 per common unit to 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 was required to maintain the general partner’s two per cent general partner interest in the Partnership, and (iv) approximately $21.3 million of cash on hand.

The acquisition of North Baja was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada’s carrying value and the Partnership’s historical financial information was recast to include the acquired entity for all periods presented. As the fair market value paid for North Baja was greater than the recorded net assets of North Baja, the excess purchase price paid was recorded as a reduction to Partners’ Equity. The effect of recasting the Partnership’s consolidated financial statements to account for the common control transaction increased the Partnership’s net income by $4.7 million and $12.8 million for the three and nine months ended September 30, 2008, respectively, from amounts previously reported. In addition, the Partnership’s net income increased by $8.3 million for the six months ended June 30, 2009 from amounts previously reported.

In connection with the acquisition, if TransCanada completes an expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona by June 30, 2010, the Partnership will pay TransCanada 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. This acquisition will be accounted for if and when the transaction occurs.

Concurrent with the acquisition of North Baja, the Partnership entered into an exchange agreement (Exchange Agreement) with its 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 incentive distribution rights (IDRs) to two per cent, down from the incentive distribution levels of the Old IDRs at 50 per cent. The incentive 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.

Note 5 Credit Facility and Long-Term Debt

(unaudited) (millions of dollars)	September 30, 2009	December 31, 2008
Senior Credit Facility due 2011	678.0	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
	737.5	536.8

TC PipeLines' Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility. At September 30, 2009, the outstanding balance on our revolving credit facility was $203.0 million, leaving $47.0 million available for future borrowings. The interest rate on the Senior Credit Facility averaged 1.01 per cent for the three months ended September 30, 2009 (2008 – 3.31 per cent). For the nine months ended September 30, 2009, the interest rate on the Senior Credit Facility averaged 1.62 per cent (2008 – 3.93 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 3.39 per cent for the three months ended September 30, 2009 (2008 – 5.23 per cent) and 4.28 per cent for the nine months ended September 30, 2009 (2008 – 5.18 per cent). Prior to hedging activities, the interest rate was 0.78 per cent at September 30, 2009 (December 31, 2008 – 2.67 per cent). At September 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	678.8
2012	3.1
	737.5

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) (millions of dollars except per unit)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Net income(a)	27.4	33.0	81.2	93.9
North Baja's contribution prior to acquisition	-	(4.7)	(8.3)	(12.8)
Net income prior to recast allocated to partners	27.4	28.3	72.9	81.1
Net income prior to recast allocated to general partner:				
General partner interest	(0.6)	(0.6)	(1.5)	(1.6)
Incentive distribution income allocation	-	(2.6)	(5.3)	(7.8)
	(0.6)	(3.2)	(6.8)	(9.4)
Net income prior to recast allocable to common units	26.8	25.1	66.1	71.7
Weighted average common units outstanding (millions)	41.2	34.9	37.0	34.9
Net income prior to recast per common unit	$0.65	$0.72	$1.78	$2.06

(a) Recast as discussed in Note 1 and Note 4.

Effective January 1, 2009, the Partnership adopted the provisions of Accounting Standards Codification (ASC) 260-10-55 Earnings Per Share – Overall – Implementation Guidance and Illustrations – Master Limited Partnerships.

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

The retrospective application of ASC 260-10-55 impacted the amount of net income allocated to the IDR holder in the nine months ended September 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 third quarter of 2008, but resulted in a reduction from $2.08 to $2.06 in net income per common unit for the nine months ended September 30, 2008.

Note 7 Cash Distributions

For the three and nine months ended September 30, 2009, we distributed $0.73 and $2.14 per common unit (2008 – $0.705 and $2.07 per common unit). The distributions for the three and nine months ended September 30, 2009 included incentive distributions to the general partner of $nil and $5.3 million, respectively (2008 - $2.6 million and $7.0 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 $0.6 million and $1.5 million for the three and nine months ended September 30, 2009, respectively (2008 - $0.5 million and $1.6 million).

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

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

(unaudited) (millions of dollars)	Three months ended September 30, 2009	 2008	Nine months ended September 30, 2009	 2008
Costs charged by TransCanada and its affiliates:				
Great Lakes	8.9	8.2	24.4	23.4
Northern Border	6.3	7.5	19.0	23.5
North Baja(a)	0.5	1.9	2.1	4.9
Tuscarora	0.6	0.9	2.2	2.9
Impact on the Partnership's net income:				
Great Lakes	3.4	3.6	10.3	10.1
Northern Border	3.1	3.2	9.1	9.6
North Baja(a)	0.5	0.7	1.8	1.9
Tuscarora	0.5	0.7	1.9	2.0

(unaudited) (millions of dollars)	September 30, 2009	December 31, 2008
Amount owed to TransCanada and its affiliates:		
Great Lakes	3.3	4.5
Northern Border	2.4	2.8
North Baja(a)	0.2	(2.5)
Tuscarora	0.5	0.8

(a) Recast as discussed in Note 1 and Note 4.

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 $33.1 million of transportation revenues under these contracts for the three months ended September 30, 2009 (2008 - $40.5 million). This amount represents 48.0 per cent of total revenues earned by Great Lakes for the three months ended September 30, 2009 (2008 – 61.0 per cent). $15.4 million of affiliated revenue is included in our equity income from Great Lakes for the three months ended September 30, 2009 (2008 - $18.8 million).

Great Lakes earned $105.5 million of transportation revenues from TransCanada and its affiliates for the nine months ended September 30, 2009 (2008 - $108.7 million). This amount represents 47.9 per cent of total revenues earned by Great Lakes for the nine months ended September 30, 2009 (2008 – 51.0 per cent). $49.0 million of this transportation revenue is included in our equity income from Great Lakes for the nine months ended September 30, 2009 (2008 - $50.5 million).

At September 30, 2009, $9.3 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 September 30, 2009 was $375.0 million (December 31, 2008 - $475.0 million). At September 30, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $25.4 million (December 31, 2008 – negative $31.7 million). Under ASC 820 – Fair Value Measurements and Disclosures, 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 nine months ended September 30, 2009, we recorded interest expense of $4.0 million and $10.9 million in regards to the interest rate swaps and options. In 2008, we recorded interest expense of $2.4 million and $4.7 million for the three and nine months ended September 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) (millions of dollars)	Nine months ended September 30, 2009	2008(a)
Decrease/(increase) in accounts receivable and other	4.6	(0.6)
Decrease in bank indebtedness	-	(1.4)
Decrease in accounts payable	(1.0)	(4.2)
(Decrease)/increase in accrued interest	(1.3)	0.1
	2.3	(6.1)
Increase in investing working capital	-	(2.8)
Decrease/(increase) in operating working capital	2.3	(3.3)

(a) Recast as discussed in Note 1 and Note 4.

Note 11 Accounting Pronouncements

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

ASC 260-10-55 Earnings Per Share – Overall – Implementation Guidance and Illustrations – Master Limited Partnerships is effective for fiscal years beginning after December 15, 2008. The Partnership adopted the provisions of ASC 260-10-55 effective January 1, 2009. Refer to Note 6 for the impact to our financial statements.

The Partnership adopted the provisions of ASC 815-10-65 Derivatives and Hedging – Overall – Transition and Open Effective Date Information, effective January 1, 2009. There was no material effect on the Partnerships' disclosure following adoption of this standard.

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

ASC 105 - Generally Accepted Accounting Principles has become the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. This standard is effective for the Partnership's interim reporting period ending after September 15, 2009. The adoption of this standard has had no impact on disclosures or amounts recorded in the Partnership's financial statements.

Note 12 Subsequent Events

On October 22, 2009, the Board of Directors of the general partner declared the Partnership's third quarter 2009 cash distribution in the amount of $0.73 per common unit, payable on November 13, 2009, to unitholders of record on October 31, 2009.

Great Lakes has approximately 830 thousand dekatherms per day (MDth/d) of longhaul capacity under contract expiring on October 31, 2010 with its largest shipper, TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts for one year for 470 MDth/d of capacity and agreed to provide other transportation services. The remaining approximate 360 MDth/d of capacity will expire October 31, 2010. Great Lakes will actively market and post the expiring capacity for shipper interest in early 2010.

The Partnership has evaluated subsequent events from October 1, 2009 through November 6, 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), North Baja Pipeline, LLC (North Baja) and Tuscarora Gas Transmission Company (Tuscarora), as a result of the Partnership's ownership interests.

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," "be "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, North Baja and Tuscarora, (together "our pipeline systems"), to market pipeline capacity on favorable terms, which is affected by:
  - future demand for and prices of natural gas;
  - the level of natural gas basis differentials;
  - competitive conditions in the overall natural gas and electricity markets;
  - the availability and relative cost 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;
  - competitive developments by Canadian and U.S. natural gas transmission companies;
  - the availability of additional storage capacity and current storage levels;
  - the level of liquefied natural gas imports;
  - weather conditions that impact supply and demand; and
  - the ability of shippers to meet credit worthiness requirements;
- 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 and additional facilities;
- 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;
-

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

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

We own a 50 per cent general partner interest in Northern Border. The other 50 per cent general partner interest is owned 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. Because North Baja was acquired from an affiliate, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at the carrying value of the previous owner and the Partnership’s historical financial information was recast to include the North Baja for all periods presented. Please read Recent Developments within this section for additional information regarding the North Baja acquisition.

Our general partner interests in Great Lakes and Northern Border, and ownership of North Baja and Tuscarora represent our only material assets at September 30, 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 the 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. Great Lakes also connects to strategic storage centers in 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, 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. North Baja is a bi-directional system which allows it to accept receipts and make deliveries of natural gas at both the interconnection with El Paso Natural Gas Company and the interconnection with Gasoducto Bajanorte. North Baja is regulated by the FERC and is operated by TransCanada.

RECENT DEVELOPMENTS

PARTNERSHIP

North Baja Acquisition and IDR Restructuring

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja from TransCanada for an initial purchase price of $271.3 million. 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 revolving credit and term loan agreement (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 was required to maintain the general partner's two per cent general partner interest in the Partnership, and (iv) approximately $21.3 million of cash on hand.

The acquisition of North Baja was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include the acquired entity for all periods presented. As the fair market value paid for North Baja was greater than the recorded net assets of North Baja, the excess purchase price paid was recorded as a reduction to Partners' Equity. The effect of recasting the Partnership's consolidated financial statements to account for the common control transaction increased the Partnership's net income by $4.7 million and $12.8 million for the three and nine months ended September 30, 2008, respectively, from amounts previously reported. In addition, the Partnership's net income increased by $8.3 million for the six months ended June 30, 2009 from amounts previously reported.

In connection with the acquisition, if TransCanada completes an expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona by June 30, 2010, the Partnership will pay TransCanada 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. This acquisition will be accounted for if and when the transaction occurs.

Concurrent with the acquisition of North Baja, the Partnership entered into an exchange agreement (Exchange Agreement) with its 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 incentive distribution levels of the Old IDRs at 50 per cent. The incentive 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.

OUR PIPELINE SYSTEMS

Great Lakes

Great Lakes has approximately 830 thousand dekatherms per day (MDth/d) of longhaul capacity under contract expiring on October 31, 2010 with its largest shipper, TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts for one year for 470 MDth/d of capacity, some at a slightly discounted rate, and agreed to provide other transportation services. The remaining approximate 360 MDth/d of capacity will expire October 31, 2010. Great Lakes will actively market and post the expiring capacity for shipper interest in early 2010. Please read Factors that Impact the Business of Our Pipeline Systems within this section for additional information regarding Great Lakes contracting.

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. 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 provide customers with natural gas transportation services to market demand areas. Great Lakes also provides access to strategic storage centers. Our pipeline systems depend upon the continued availability of natural gas production and reserves in the regions they access. The primary region accessed by our pipeline systems, excluding North Baja, is the WCSB. The Net WCSB Flows to Markets are dependent upon WCSB natural gas production levels, demand for natural gas in Western Canada, storage capacity for Western Canadian natural gas and demand for storage injection. The Net WCSB Flows to Markets were 1.2 billion cubic feet per day (Bcf/day) lower in the third quarter of 2009 compared to the same period in 2008, due primarily to a decrease in production which was slightly offset by a reduction in net injections into Western Canadian storage.

Decreased demand in North America related to the economic environment, combined with increased production from U.S. shale plays and high levels of natural gas in storage have resulted in a supply/demand imbalance, which has contributed to weaker commodity prices for natural gas over the last year and is expected to continue into 2010. These low commodity prices have resulted in reductions in exploration and development activity for natural gas as well as some levels of voluntary production curtailments in the WCSB. Decreases in WCSB production are expected to continue throughout the remainder of 2009 and into 2010 mainly related to the low commodity price environment. While production from U.S. shale plays has increased, overall U.S natural gas production has decreased compared to previous periods.

Strengthening of the North American economy, decreased natural gas inventories as a result of reduced production levels and cold winter weather causing increased heating related demand, are factors that would positively affect natural gas prices.

Western Canadian natural gas in storage is currently at a five year high. U.S. working gas storage levels are also at record high levels. The summer is traditionally a storage injection period. However, due to the high levels of natural gas already in storage at the beginning of the storage injection season, lower amounts of gas were injected over the third quarter compared to levels seen in previous years. Normally, lower levels of injection into Western Canadian gas storage results in more WCSB gas available for export; however, this has been offset by less WCSB production. The high U.S. gas storage levels are negatively impacting the demand for natural gas in the market areas that storage serves, as well as impacting demand for transportation services related to storage injection. High overall storage levels have a dampening effect on natural gas prices which in turn reduces ongoing production.

Factors which may mitigate declining WCSB production in the future include strengthening gas prices which will support continued exploration and development of new fields in Western Canada by WCSB natural gas producers. Over the long term, we expect WCSB natural gas producers will 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 are constructed, and longer term potential associated with the proposed development of the Mackenzie Delta in Northern Canada and the North Slope of Alaska is realized.

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 through the remainder of 2009 and into 2010 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 have resulted in a competitive advantage for this fuel option and a resulting increase in demand for natural gas in this sector.

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, relative 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. Please read Recent Developments section above for a discussion of Great Lakes contracting.

Net WCSB Flows to Markets is one of the factors which impacts 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 and into 2010.

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Throughput on the Great Lakes pipeline system in the third quarter of 2009 (average 1,622 MMcf/d) was lower compared to the same period in 2008 (average 2,122 MMcf/d). The lower volumes in 2009 are due mainly to underutilization of long-term firm contracts by Great Lakes' major shipper, TransCanada, related to the early fill of storage during the traditional summer storage-fill season, lower power generation demand due to the cooler than normal summer weather in the market areas served by Great Lakes, and decreased overall demand related to the economic environment. The underutilization of the long-term firm contracts was somewhat offset by daily sales of capacity. Decreases in throughput related to underutilization of firm contracts have a minimal impact on revenue. If the level of firm contracts decreases, Great Lakes may experience increased volatility in revenues as a result of changes in throughput.

Throughput on Northern Border declined in the third quarter of 2009 (average 1,774 MMcf/d) relative to the same period in 2008 (average 1,813 MMcf/d) as the Midwest markets served by Northern Border had cooler than normal weather conditions, decreased overall demand related to the economic environment, and reduced Net WCSB Flows to Markets. Decreased overall demand also reduces the ability to contract available pipeline capacity serving this market area. Changes in throughput on Northern Border related to capacity without firm contracts impacts Northern Border's revenues.

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

Customers and Contracting

The reduced level of Net WCSB Flows to Markets has resulted in an environment in which the pipeline capacity serving the WCSB exceeds demand. In this environment, there is little incentive for shippers to make long-term commitments for capacity and the trend towards shorter term contracts is expected to continue for Great Lakes and Northern Border. As well, there may be increased seasonality with respect to pipeline throughput and revenues.

Prevailing market conditions and dynamic competitive factors in North America, particularly lower Net WCSB Flows to Markets, increased supply from other supply basins to our pipelines systems' market area, and the current economic conditions affecting the demand for natural gas, will continue to impact the value of transportation on our pipeline systems and their ability to market available capacity.

Great Lakes' average contracted capacity was 103 per cent of its design capacity for the third quarter of 2009 compared to 95 per cent for the same period last year. At September 30, 2009, 92 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 1.9 years. Substantially all of the firm contracts in place at September 30, 2009 are in place until October 31, 2010.

Great Lakes has approximately 985 MDth/d of longhaul capacity expiring on October 31, 2010, of which approximately 830 MDth/d is contracted with TransCanada. On November 3, 2009, Great Lakes and TransCanada renewed contracts for one year for 470 MDth/d of capacity, some at a slightly discounted rate, and agreed to provide other transportation services. TransCanada has elected to turn back approximately 360 MDth/d as of October 31, 2010. Great Lakes continues shipper negotiations on the remaining capacity. Great Lakes will actively market and post any expiring capacity for shipper interest in early 2010. Great Lakes may discount transportation capacity as needed to optimize revenue.

Northern Border's average contracted capacity was 70 per cent of its design capacity for the third quarter of 2009 compared to 79 per cent for the same period last year. At September 30, 2009, Northern Border had approximately 47 per cent of its design capacity uncontracted for the remainder of the year. In the absence of renewals on maturing contracts, the design capacity uncontracted will increase to 65 per cent beginning April 1, 2010. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue. As at September 30, 2009, the weighted average remaining life of Northern Border's firm transportation contracts was 2.0 years.

Tuscarora operates under long-term contracts and had 98 per cent of its design capacity contracted for the third quarter of 2009, consistent with the same period last year. As at September 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 11.0 years.

North Baja operates under long-term contracts and, as at September 30, 2009, in excess of 100 per cent of its physical capacity was contracted on a firm basis for the remainder of the year. Due to North Baja's bi-directional nature, it has the capacity to accept receipts at both ends of its system. As at September 30, 2009, 79 per cent of the design capacity for southbound receipts and 64 per cent of the design capacity for northbound receipts was contracted on a firm basis for the remainder of the year. The weighted average remaining life of the contracts at September 30, 2009 was 16.5 years.

Competition

Our pipeline systems compete primarily with other interstate and intrastate pipelines in the transportation of natural gas. Changes in North American gas flow patterns are expected as a result of recent and proposed pipeline projects which are changing the supply competition in the markets served by our pipeline systems. 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.

As the pipeline capacity serving the WCSB exceeds demand currently, there is competition for Net WCSB Flows to Markets. Factors impacting the competition for Net WCSB Flows to Markets include levels of firm transportation contracts on each pipeline, demand for natural gas in the regions served by each pipeline, and relative transportation values on each pipeline. In the short term, factors impacting the competition for Net WCSB Flows to Markets include high natural gas storage levels in Eastern Canada, Michigan and California.

The Western segment of the Rockies Express Pipeline (REX West) introduced new gas supplies from the Rockies natural gas basin into the markets served by Northern Border, particularly its Mid-Continent market, starting in the second quarter of 2008. The increased supply resulted in downward pressure on prices in those markets, which negatively impacted Northern Border's ability to contract available capacity. The Eastern segment of the Rockies Express Pipeline (REX East) was placed into interim service on June 29, 2009 to Lebanon, Ohio. The interim service of REX East is mitigating excess supply in the Mid-Continent region; however, the movement of these natural gas supplies further east following the full in-service of REX East is expected to create additional supply in the markets served by Northern Border and Great Lakes, which may also provide opportunities for Great Lakes to market its Eastern zone services. Rockies Express Pipeline has announced that full in-service of REX East to Clarington, Ohio is scheduled for November 2009.

Two new pipeline projects transporting 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 Midwest market area, Eastern U.S. market area, or to the Gulf market depending on demand. The additional supply delivered to Eastern markets has caused and is expected to continue to cause natural gas formerly delivered to Eastern markets to be delivered into the Chicago market area.

Increased supply in the Midwest markets served by Northern Border and Great Lakes as a result of changed pipeline flows has resulted in downward pressure on prices in this region. Additional supplies 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 on Northern Border to Chicago materially decrease. Additional supply in the Michigan market may impact Great Lakes' ability to renew contracts with its customers and market expiring capacity.

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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 nine months ended September 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 Accounting Standards Codification (ASC) 820-10-65 Fair Value Measurements and Disclosures – Overall – Transition and Open Effective Date Information for all non-financial assets and liabilities measured on a non-recurring basis subsequent to initial recognition, effective January 1, 2009. The adoption of ASC 820-10-65 has had no material impact on our results of operations or financial position.

ASC 260-10-55 Earnings Per Share – Overall – Implementation Guidance and Illustrations – Master Limited Partnerships is effective for fiscal years beginning after December 15, 2008. The Partnership adopted the provisions of ASC 260-10-55 effective January 1, 2009. Refer to Note 6 for the impact to our financial statements.

The Partnership adopted the provisions of ASC 815-10-65 Derivatives and Hedging – Overall – Transition and Open Effective Date Information, effective January 1, 2009. There was no material effect on the Partnerships' disclosure following adoption of this standard.

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

ASC 105 - Generally Accepted Accounting Principles has become the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. This standard is effective for the Partnership’s interim reporting period ending after September 15, 2009. The adoption of this standard has had no impact on disclosures or amounts recorded in the Partnership’s financial statements.

Net Income

To supplement our financial statements, we have presented a comparison of the earnings contribution components from each of our investments. The contributions from Tuscarora and North Baja are included under Other Pipes. 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)	For the three months ended September 30, 2009					For the three months ended September 30, 2008				
(millions of dollars)	PipeLP	Other Pipes	Corp	GLGT	NBPC(1)	PipeLP	Other Pipes	Corp	GLGT	NBPC(1)
Transmission revenues	17.5	17.5	-	68.9	65.2	8.2	8.2	-	66.7	67.7
Operating expenses	(3.5)	(2.5)	(1.0)	(16.5)	(19.0)	(2.3)	(1.4)	(0.9)	(17.1)	(19.3)
	14.0	15.0	(1.0)	52.4	46.2	5.9	6.8	(0.9)	49.6	48.4
Depreciation	(3.7)	(3.7)	-	(14.7)	(15.6)	(1.8)	(1.8)	-	(14.7)	(15.3)
Financial charges, net and other	(6.6)	(1.0)	(5.6)	(8.1)	(9.1)	(7.7)	(1.1)	(6.6)	(8.0)	7.1
Michigan business tax	-	-	-	(1.3)	-	-	-	-	(1.2)	-
				28.3	21.5				25.7	40.2
Equity income	23.7	-	-	13.2	10.5	31.9	-	-	12.0	19.9
Net income prior to recast	27.4	10.3	(6.6)	13.2	10.5	28.3	3.9	(7.5)	12.0	19.9
North Baja's contribution prior to acquisition(2)	-	-	-	-	-	4.7	4.7	-	-	-
Net income(2)	27.4	10.3	(6.6)	13.2	10.5	33.0	8.6	(7.5)	12.0	19.9

(unaudited)	For the nine months ended September 30, 2009					For the nine months ended September 30, 2008				
(millions of dollars)	PipeLP	Other Pipes	Corp	GLGT	NBPC(1)	PipeLP	Other Pipes	Corp	GLGT	NBPC(1)
Transmission revenues	34.1	34.1	-	220.4	193.9	23.3	23.3	-	213.9	212.8
Operating expenses	(10.2)	(5.1)	(5.1)	(49.6)	(55.8)	(6.8)	(3.7)	(3.1)	(45.9)	(57.5)
	23.9	29.0	(5.1)	170.8	138.1	16.5	19.6	(3.1)	168.0	155.3
Depreciation	(7.2)	(7.2)	-	(43.9)	(46.4)	(5.1)	(5.1)	-	(43.9)	(45.8)
Financial charges, net and other	(20.9)	(3.3)	(17.6)	(24.4)	(27.4)	(22.8)	(3.1)	(19.7)	(24.4)	(12.1)
Michigan business tax	-	-	-	(4.4)	-	-	-	-	(4.2)	-
				98.1	64.3				95.5	97.4
Equity income	77.1	-	-	45.6	31.5	92.5	-	-	44.4	48.1
Net income prior to recast	72.9	18.5	(22.7)	45.6	31.5	81.1	11.4	(22.8)	44.4	48.1
North Baja's contribution prior to acquisition(2)	8.3	8.3	-	-	-	12.8	12.8	-	-	-
Net income(2)	81.2	26.8	(22.7)	45.6	31.5	93.9	24.2	(22.8)	44.4	48.1

(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.

(2) Because North Baja was acquired from TransCanada, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include the acquired entity for all periods presented.

Third Quarter 2009 Compared with Third Quarter 2008

Net income was $27.4 million in the third quarter of 2009, a decrease of $5.6 million compared to $33.0 million for the same period last year. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast was $27.4 million in the third quarter of 2009, a decrease of $0.9 million compared to $28.3 million for the same period last year. This decrease is primarily due to lower equity income from Northern Border, which decreased as a result of the $16.1 million (Partnership share - $8.1 million) gain on sale of Bison Pipeline LLC (Bison) in 2008, partially offset by a $6.2 million contribution from North Baja since the acquisition.

Equity income from Great Lakes increased $1.2 million to $13.2 million in the third quarter of 2009, compared to $12.0 million for the same period last year. The increase in equity income was primarily due to increased transmission revenues. Utilization of long-term firm contracts, some of which are priced at lower rates than during the same period last year, decreased significantly in the third quarter of 2009 compared to the same period last year; however, this had minimal impact on revenue. The sale of short-term services contributed to increased overall transmission revenues of $2.2 million for the three months ended September 30, 2009 compared to the same period last year.

Equity income from Northern Border was $10.5 million in the third quarter of 2009, a decrease of $9.4 million compared to $19.9 million for the same period last year. The decrease in equity income was primarily due to a $16.1 million (Partnership share - $8.1 million) gain on sale of Bison in 2008. Excluding this gain, Northern Border's net income decreased $2.6 million compared to the same period last year due to decreased transmission revenues. Northern Border's transmission revenues decreased due to reduced system utilization. Northern Border continues to be negatively impacted by increased supply competition as a result of increased U.S. natural gas supplies being transported to the Mid-western and Eastern markets from new U.S. supply sources, including the Rockies Basin and southern shale gas, which is displacing demand for gas from traditional natural gas sources including the WCSB. Additionally, reduced overall demand for natural gas related to the current economic environment is affecting demand for Northern Border's transportation.

Net income from Other Pipes (North Baja and Tuscarora) increased $1.7 million to $10.3 million in the third quarter of 2009 compared to $8.6 million for the same period last year. Excluding the contribution from North Baja prior to the acquisition, net income from Other Pipes prior to recast increased $6.4 million to $10.3 million in the third quarter of 2009 compared to $3.9 million for the same period last year. This increase is primarily due to the acquisition of North Baja which contributed $6.2 million to net income for the quarter ended September 30, 2009. As the acquisition was accounted for as a transaction between entities under common control, North Baja contributed $4.7 million to net income for the quarter ended September 30, 2008.

Costs at the Partnership level decreased by $0.9 million to $6.6 million in the third quarter of 2009 compared to the same period last year. This decrease is primarily due to decreased financial charges as a result of lower interest rates, partially offset by losses on interest rate derivatives.

Nine Months Ended September 30, 2009 Compared with Nine Months Ended September 30, 2008
Net income decreased $12.7 million to $81.2 million for the nine months ended September 30, 2009 compared to $93.9 million for the same period last year. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast decreased $8.2 million to $72.9 million for the nine months ended September 30, 2009 compared to $81.1 million for the same period last year. This decrease is primarily due to lower equity income from Northern Border, partially offset by the contribution from North Baja since the acquisition. North Baja contributed $6.2 million to net income prior to recast for the nine months ended September 30, 2009.

Equity income from Great Lakes was $45.6 million for the nine months ended September 30, 2009, an increase of $1.2 million compared to $44.4 million in the same period last year. The increase in equity income was primarily due to increased transmission revenues, partially offset by an increase in operating expenses. Utilization of long-term firm contracts decreased in the nine months ended September 30, 2009 compared to the same period last year with minimal impact to revenues due to reservation charges contained in the contracts. However, short-term services contributed to increased transmission revenues of $6.5 million for the nine months ended September 30, 2009 compared to the same period last year. Great Lakes' operating expenses increased $3.7 million for the nine months ended September 30, 2009 compared to the same period in the prior year primarily due to increased pipeline maintenance costs, partially offset by lower property and other taxes.

Equity income from Northern Border was $31.5 million for the nine months ended September 30, 2009, a decrease of $16.6 million compared to $48.1 million in the same period last year. The decrease in equity income was partially due to a $16.1 million (Partnership share - $8.1 million) gain on sale of Bison in 2008. Excluding this gain, Northern Border's net income decreased $17.0 million compared to the same period last year primarily due to decreased transmission revenues, partially offset by lower operating expenses. Northern Border's transmission revenues decreased by $18.9 million for the nine months ended September 30, 2009 compared to the same period last year, primarily due to reduced system utilization. Northern Border continues to be negatively impacted by the incremental natural gas supply from the Rockies Basin into the markets it serves as a result of the in-service of REX West in the second quarter of 2008, other new pipeline projects completed in the second quarter of 2009 which have resulted in increased supply into Northern Border's markets, and reduced overall demand related to the economic environment. Northern Border's operating expenses decreased by $1.7 million compared to the same period last year primarily due to adjustments to reflect property tax amounts paid.

Net income from Other Pipes (North Baja and Tuscarora) increased $2.6 million to $26.8 million for the nine months ended September 30, 2009 compared to $24.2 million for the same period last year. Excluding the contribution from North Baja prior to the acquisition, net income from Other Pipes prior to recast increased $7.1 million to $18.5 million for the nine months ended September 30, 2009 compared to $11.4 million for the same period last year. This increase is primarily due to the acquisition of North Baja which contributed $6.2 million to net income prior to recast for the nine months ended September, 30, 2009 and an increase in Tuscarora's transmission revenues. Tuscarora's transmission revenues were higher resulting from the Likely compressor station expansion project that went into service on April 1, 2008. As the North Baja acquisition was accounted for as a transaction between entities under common control, North Baja contributed a total of $14.5 million and $12.8 million to net income for the nine months ended September 30, 2009 and 2008, respectively.

Costs at the Partnership level for the nine months ended September 30, 2009 were comparable to the same period last year, as a decrease in financial charges was offset by an increase in operating expenses. Financial charges, net and other, decreased by $2.1 million primarily due to lower interest rates, partially offset by losses on interest rate derivatives. Operating expenses increased by $2.0 million due to costs relating to the North Baja acquisition and the amendment to the IDRs.

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 September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Net income(a)	27.4	33.0	81.2	93.9
North Baja's contribution prior to acquisition(a)	-	(4.7)	(8.3)	(12.8)
Net income prior to recast	27.4	28.3	72.9	81.1
Add:				
Cash distributions from Great Lakes(b)	19.8	19.3	54.0	55.0
Cash distributions from Northern Border(b)	11.8	22.6	58.5	72.0
Cash flows provided by North Baja's operating activities	8.5	-	8.5	-
Cash flows provided by Tuscarora's operating activities	6.9	7.2	18.9	17.3
	47.0	49.1	139.9	144.3
Less:				
Equity income from investment in Great Lakes	(13.2)	(12.0)	(45.6)	(44.4)
Equity income from investment in Northern Border	(10.5)	(19.9)	(31.5)	(48.1)
North Baja's net income	(6.2)	-	(6.2)	-
Tuscarora's net income	(4.1)	(3.9)	(12.3)	(11.4)
	(34.0)	(35.8)	(95.6)	(103.9)
Partnership cash flows prior to recast	40.4	41.6	117.2	121.5
Partnership cash flows prior to recast allocated to general partner (c)	(0.7)	(3.2)	(7.1)	(9.4)
Partnership cash flows prior to recast allocated to common units	39.7	38.4	110.1	112.1
Cash flows provided by North Baja's pre-acquisition operating activities(a)	-	5.2	9.7	14.0
Cash distributions declared	(30.7)	(27.8)	(89.2)	(83.0)
Cash distributions declared per common unit(d)	$ 0.730	$ 0.705	$ 2.165	$ 2.110
Cash distributions paid	(30.7)	(27.8)	(86.3)	(80.8)
Cash distributions paid per common unit(d)	$ 0.730	$ 0.705	$ 2.140	$ 2.070
	41.2	34.9	37.0	34.9

Weighted average common units outstanding
(millions)

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(a) Because North Baja was acquired from TransCanada, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include the acquired entity for all periods presented. To calculate recasted partnership cash flows, add partnership cash flows prior to recast and cash flows provided by North Baja's pre-acquisition operating activities.

(b) 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, except that the distribution paid by Northern Border in the third quarter of 2008 included a special distribution of $16.4 million (Partnership share - $8.2 million) related to the sale of Bison.

(c) Partnership cash flows prior to recast 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 ASC 260-10-55 Earnings Per Share – Overall – Implementation Guidance and Illustrations – Master Limited Partnerships, Partnership cash flows allocated to general partner in the third quarter of 2008 remained the same. Partnership cash flows allocated to the general partner for the nine months ended September 30, 2008 increased from $8.6 million to $9.4 million.

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

Third Quarter 2009 Compared with Third Quarter 2008

Partnership cash flows decreased $1.2 million to $40.4 million for the third quarter of 2009 compared to $41.6 million, prior to recast, for the same period last year. This decrease is primarily a result of decreased cash distributions from Northern Border, partially offset by cash flows provided by North Baja's operating activities of $8.5 million. Northern Border's decreased distribution was primarily due to a special one-time distribution for the proceeds received in connection with the sale of Bison in 2008 and lower net income, partially offset by a reduction in maintenance capital expenditures. As the North Baja acquisition was accounted for as a transaction between entities under common control, North Baja contributed $5.2 million to partnership cash flows for the quarter ended September 30, 2008.

The Partnership paid distributions of $30.7 million in the third quarter of 2009, an increase of $2.9 million compared to the same period in the prior year due to an increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts. In the third quarter of 2009, proceeds from equity issuances of $80.0 million were used to partially fund the acquisition of North Baja. The Partnership funded the balance of the acquisition cost with a $170.0 million draw on its Senior Credit Facility and cash on hand. We borrowed an additional net $33.0 million from our Senior Credit Facility during the three months ended September 30, 2009 to partially fund an equity contribution of $38.0 million to Northern Border.

Nine Months Ended September 30, 2009 Compared with Nine Months Ended September 30, 2008

Partnership cash flows prior to recast decreased $4.3 million to $117.2 million for the nine months ended September 30, 2009 compared to $121.5 million for the same period of last year. This decrease is primarily a result of decreased cash distributions from Northern Border, partially offset by cash flows provided by North Baja's operating activities of $8.5 million. Northern Border's decreased distribution was primarily due to lower net income, partially offset by a reduction in maintenance capital expenditures. As the North Baja acquisition was accounted for as a transaction between entities under common control, North Baja contributed a total of $18.2 million and $14.0 million to partnership cash flows for the nine months ended September 30, 2009 and 2008, respectively.

The Partnership paid distributions of $86.3 million in the nine months ended September 30, 2009, an increase of $5.5 million compared to the same period in the prior year due to an increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts. In the third quarter of 2009, proceeds from equity issuances of $80.0 million were used to partially fund the acquisition of North Baja. The Partnership funded the balance of the acquisition cost with a $170.0 million draw on its Senior Credit Facility and cash on hand. We borrowed an additional net $33.0 million from our Senior Credit Facility during the nine months ended September 30, 2009 to partially fund equity contributions of $42.3 million to Northern Border.

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 from North Baja and Tuscarora, and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

The Partnership's Debt and Credit Facility

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

(unaudited) (millions of dollars)	Payments Due by Period Total	Less Than 1 Year	Long-term Portion
Senior Credit Facility due 2011	678.0	-	678.0
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	737.5	4.4	733.1

TC PipeLines' Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility. At September 30, 2009, the outstanding balance on our revolving credit facility was $203.0 million, leaving $47.0 million available for future borrowings.

The interest rate on the Senior Credit Facility averaged 1.01 per cent for the three months ended September 30, 2009 (2008 – 3.31 per cent). For the nine months ended September 30, 2009, the interest rate on the Senior Credit Facility averaged 1.62 per cent (2008 – 3.93 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 3.39 per cent for the three months ended September 30, 2009 (2008 – 5.23 per cent) and 4.28 per cent for the nine months ended September 30, 2009 (2008 – 5.18 per cent). Prior to hedging activities, the interest rate was 0.78 per cent at September 30, 2009 (December 31, 2008 – 2.67 per cent). At September 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 September 30, 2009 was $375.0 million (December 31, 2008 - $475.0 million). At September 30, 2009, the fair value of the interest rate swaps accounted for as hedges was negative $25.4 million (December 31, 2008 – negative $31.7 million). Under ASC 820 – Fair Value Measurements and Disclosures, 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 nine months ended September 30, 2009, we recorded interest expense of $4.0 million and $10.9 million in regards to the interest rate swaps and options. In 2008, we recorded interest expense of $2.4 million and $4.7 million for the three and nine months ended September 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 Third Quarter Cash Distribution

On October 22, 2009, the Board of Directors of the general partner declared the Partnership's 2009 third quarter cash distribution in the amount of $0.73 per common unit. This cash distribution, totaling $30.7 million, will be paid on November 13, 2009 to unitholders of record as of October 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 reflects 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 required an equity contribution of $76.0 million in the third quarter of 2009, of which the Partnership's share was $38.0 million, to partially fund $200.0 million of debt which matured on September 1, 2009. The Partnership financed this equity contribution with a combination of debt and operating cash flows. In the first quarter of 2009, the Partnership made an equity contribution of $4.3 million to Northern Border, representing the Partnership's 50 per cent share of an $8.6 million cash call issued by Northern Border to complete the Des Plaines Project.

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 September 30, 2009:

	Payments Due by Period		
(unaudited)		Less than 1	Long-term
(millions of dollars)	Total	year	Portion
8.74% series Senior Notes due 2009 to 2011	30.0	10.0	20.0
6.73% series Senior Notes due 2010 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 September 30, 2009 (December 31, 2008 - $232.0 million). As at September 30, 2009, Great Lakes was in compliance with all of its financial covenants.

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Debt and Credit Facility of Northern Border

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

(unaudited) (millions of dollars)	Payments Due by Period Total	Less than 1 year	Long-term Portion
$250 million credit agreement due 2012 (a)	209.0	-	209.0
6.24% senior notes due 2016	100.0	-	100.0
7.50% senior notes due 2021	250.0	-	250.0
Total	559.0	-	559.0

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

As of September 30, 2009, Northern Border had outstanding borrowings of $209.0 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 0.66 per cent at September 30, 2009.

Senior Notes

On August 26, 2009, Northern Border issued $100.0 million of 6.24 per cent Senior Notes due August 26, 2016. The proceeds of the 6.24 per cent Senior Notes, along with equity contributions, borrowings under the revolving credit agreement and working capital, were used to repay $200.0 million of 7.75 per cent Senior Notes due September 1, 2009.

Interest Rate Collar Agreement

At September 30, 2009, Northern Border's balance sheet reflected an unrealized loss of approximately $0.4 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 nine months ended September 30, 2009, Northern Border recorded interest expense of $1.3 million and $3.3 million, respectively, under the Collar Agreement. The hedge was effective for the three and nine months ended September 30, 2009; therefore, it 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. During the second quarter of 2009, TransCanada internally announced a reorganization of its U.S. operations, which will include the relocation of some employees and equipment, and some severance costs, with certain operational cost savings to be expected in the future. According to our operating agreements, some of these costs could be borne by our pipeline systems. It is expected that the reorganization will be complete in 2010, with some activities 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 the 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 composed 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 $33.1 million of transportation revenues under these contracts for the three months ended September 30, 2009 (2008 - $40.5 million). This amount represents 48.0 per cent of total revenues earned by Great Lakes for the three months ended September 30, 2009 (2008 – 61.0 per cent). $15.4 million of affiliated revenue is included in our equity income from Great Lakes for the three months ended September 30, 2009 (2008 - $18.8 million).

Great Lakes earned $105.5 million of transportation revenues from TransCanada and its affiliates for the nine months ended September 30, 2009 (2008 - $108.7 million). This amount represents 47.9 per cent of total revenues earned by Great Lakes for the nine months ended September 30, 2009 (2008 – 51.0 per cent). $49.0 million of this transportation revenue is included in our equity income from Great Lakes for the nine months ended September 30, 2009 (2008 - $50.5 million).

At September 30, 2009, $9.3 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2008 - $12.5 million).

Great Lakes has approximately 830 MDth/d of longhaul capacity under contract expiring on October 31, 2010 with its largest shipper, TransCanada. On November 3, 2009, Great Lakes and TransCanada signed an agreement to renew 470 MDth/d of capacity under a contract expiring on October 31, 2011. The remaining approximately 360 MDth/d of capacity will expire October 31, 2010. Great Lakes will actively market and post the expiring capacity for shipper interest in early 2010.

Lease Agreements

In July 2009, Northern Border entered into an agreement with Northern Border's operator and TransCanada Keystone Pipeline LP (Keystone), an affiliate of TC PipeLines, LP, for Keystone to lease vehicles and equipment from Northern Border. There have not been any charges under this agreement for the three months ended September 30, 2009.

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 ASC 815 – Derivatives and Hedging, 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 ASC 815 and meets specific hedge accounting criteria. Qualifying financial instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

MARKET RISK AND INTEREST RATE RISK

From time to time, and in order to finance our business and that of our pipeline systems, the Partnership and our pipeline systems 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 September 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 September 30, 2009, the fair value of the Partnership's interest rate swaps accounted for as hedges was negative $25.4 million (December 31, 2008 – negative $31.7 million), of which $12.1 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 September 30, 2009, we had $678.0 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 September 30, 2009, our annual interest expense would have increased and our net income would have decreased by $3.0 million; and if LIBOR interest rates hypothetically decreased by one per cent (100 basis points) compared to the rates in effect as of September 30, 2009, our annual interest expense would have decreased and our net income would have increased by $3.0 million. These amounts have been determined by considering the impact of the hypothetical interest rates on unhedged debt outstanding as of September 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 revolving credit agreement. 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 September 30, 2009, 63 per cent of Northern Border's outstanding debt was at fixed rates (December 31, 2008 – 71 per cent). Northern Border utilized its Collar Agreement to limit the variability of the interest rate on $140.0 million of variable-rate borrowings 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 September 30, 2009, Northern Border's annual interest expense would increase and its net income would decrease by approximately $0.7 million; and if interest rates hypothetically decreased by one per cent (100 basis points) compared with rates in effect as of September 30, 2009, Northern Border's annual interest expense would decrease and its net income would increase by approximately $0.7 million.

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

OTHER RISKS

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

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 September 30, 2009, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $5.8 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 September 30, 2009, the Partnership has a committed revolving bank line of $250.0 million maturing in December 2011. As of September 30, 2009, the outstanding balance on this facility was $203.0 million. In addition, at September 30, 2009, Northern Border has a committed revolving bank line of $250.0 million maturing in April 2012. As of September 30, 2009, $209.0 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 $0.5 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 September 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 factors 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.

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

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

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

Ongoing changes in these factors and customers' ability to adjust to changing market conditions may cause Great Lakes and Northern Border to sell a significant portion of available capacity on a short-term basis. The weighted average lives of Great Lakes' and Northern Border's contracts have generally declined over time. As of September 30, 2009, the weighted average remaining lives of Great Lakes' and Northern Border's contracts were 1.9 years and 2.0 years, respectively. Great Lakes has approximately 830 thousand dekatherms per day (MDth/d) of longhaul capacity under contract expiring on October 31, 2010 with its largest shipper, TransCanada. Great Lakes and TransCanada renewed contracts for one year for 470 MDth/d of capacity, some at a slightly discounted rate, and agreed to provide other transportation services. The remaining approximate 360 MDth/d of capacity will expire October 31, 2010.

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

Item 6.	Exhibits
No.	Description
*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. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 4, 2009 (File No. 000-26091)).
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:	November 6, 2009	By:	/s/ Russell K. Girling Russell K. Girling Chairman, Chief Executive Officer and Director TC PipeLines GP, Inc. (Principal Executive Officer)
Date:	November 6, 2009	By:	/s/ Amy W. Leong Amy W. Leong Controller TC PipeLines GP, Inc. (Principal Financial Officer)