Tolls, Tariff, Facilities & Procedures Committee

Resolution

T2012-02: 2013+ Revenue Requirement Discussions

Resolution

The Tolls, Tariff, Facilities & Procedures Committee ("TTFP") agrees to the provisions of the NGTL 2013-2014 Revenue Requirement Settlement (the "Settlement"), as attached.

The TTFP also supports revision of the existing 2013 interim rates, to be effective September 1, 2013 pending the Board's adjudication of the Settlement Application, that reflects the difference between the 2013 Settlement revenue requirement and the 2013 interim revenue requirement.

Background

On December 11, 2013, the TTFP adopted Issue T2012-02. In order to ensure that the discussions were inclusive of all interested and potentially affected parties, NGTL sent a letter to all NGTL System customers, TTFP members and additional stakeholders inviting them to participate in the discussions and negotiations.

A task force of the TTFP was established to conduct the negotiations. The first meeting of the 2013+ Revenue Requirement Task Force took place on January 31, 2013 and was followed by numerous additional task force meetings. This process resulted in the Settlement.

Next Steps

NGTL will file an Application with the National Energy Board ("NEB") for approval of the Settlement, 2013 final tolls resulting from implementation of the Settlement, and revision of existing 2013 interim tolls, effective September 1, 2013, pending the NEB's adjudication of the Settlement Application. This resolution and the attached Settlement will be filed in support of the Application.

NOVA Gas Transmission Ltd.

2013-2014 Revenue Requirement Settlement (the "**Settlement**")

OVERVIEW

This Settlement includes all elements of NOVA Gas Transmission Ltd.'s ("**NGTL**") annual revenue requirements for 2013 and 2014 (the "**Term**").

Rates during the Term of the Settlement will be based on the revenue requirement for each year and calculated in accordance with the tolling methodology in effect at the time.

1. **REVENUE REQUIREMENT FOR EACH YEAR OF THE TERM**

The revenue requirement for the period commencing January 1 and including December 31 of each year of the Term shall be calculated based on the inclusion of the following fixed cost component and forecast flow-through costs.

The 2013 revenue requirement is forecast to be $1,437 million. The 2014 revenue requirement will be forecast based on the fixed and flow-through cost components.

(A) **Fixed Component**

Operations, Maintenance, and Administrative Costs ("**OM&A**") costs for each year of the Term shall be fixed at:

2013: $190,000,000
2014: $198,000,000

(B) **Flow-Through Components**

All other components of the annual revenue requirements for the Term, including without limitation all costs set out in sections 1(B)(i) to (xvii) and any balances in deferral accounts set out in Section 2(D) for the previous year, shall be flow-through costs (the "**Flow-Through Costs**"). Any variance between the actual and forecast Flow-Through Costs and revenues shall be included in the appropriate deferral account, set out in Section 2(D), to be included in the revenue requirement for the following year.

Flow-Through Costs shall include, but not be limited to, the following:

(i) **Transportation by Others ("TBO") Costs**

(a) Costs for existing TBO arrangements shall be included in the revenue requirement during the Term; and

(b) Costs for new TBO arrangements shall be included in the revenue requirement during the Term if such costs have been approved by the National Energy Board ("**NEB**").

TBO cost for 2013 is forecast to be $91,600,000.

(ii) **Pipeline Integrity Expense**

Pipeline integrity expense for 2013 is forecast to be $64,795,000.

(iii) **NEB Cost Recovery**

The NEB cost recovery for 2013 is forecast to be $15,179,000.

(iv) **Return**

For each year of the Term, NGTL will have a deemed equity/debt ratio of 40%/60% and a return on equity of 10.1%. Return on equity for 2013 is forecast to be $231,933,000. Return on debt for 2013 is forecast to be $210,691,000.

(v) **Income Taxes**

For 2013, income tax expense is forecast to be $56,652,000.

(vi) **Depreciation**

Depreciation expense shall be calculated using the rates for each asset class as provided in Appendix 1 and Appendix 2. Acceptance of these depreciation rates is without prejudice to any position that may be taken by any party in any future forum and does not set a precedent with regard to future treatment of depreciation expense.

For 2013, the forecast composite depreciation rate that results from the rates for the asset classes set out in Appendix 1 is 3.05% and the forecast expense is $321,346,000.

For 2014, the forecast composite depreciation rate that results from the rates for the asset classes set out in Appendix 2 is 3.12%.

(vii) **Regulatory Proceeding Costs**

The regulatory proceeding costs for 2013 are forecast to be $1,450,000.

(viii) **Emissions Compliance Costs**

Emissions compliance costs for 2013 are forecast to be $4,000,000.

(ix) **Municipal and Other Taxes**

Municipal and other taxes for 2013 are forecast to be $113,410,000.

(x) **Regulatory Amortizations**

Deferral Account balances from the preceding year will be included in the revenue requirement. The total deferred balance from 2012 is an over-collection of $58,340,000 to be a credit in the 2013 revenue requirement.

(xi) **Compressor Repair Expense**

Compressor repair expense for 2013 is forecast to be $2,475,000. Other costs related to major and minor compressor repair and overhaul will be included in rate base.

(xii) **Pension and Other Post Employment Benefits ("OPEB") Actuarial Loss Amortization**

The Pension and OPEB Actuarial Loss Amortization for 2013 is forecast to be $16,607,000.

(xiii) **Uninsured Losses**

Uninsured losses for each year of the Term are forecast to be $2,000,000.

(xiv) **Annual Foreign Exchange Amortization Amount**

The foreign exchange amortization amount for 2013 is forecast to be a $901,000 credit in the 2013 revenue requirement.

(xv) **Foreign Exchange on Interest Payments**

Foreign exchange on interest payments for 2013 is forecast to be a $8,671,000 credit in the 2013 revenue requirement.

(xvi) **CO_2 Management Service Costs**

CO_2 Management Service costs for 2013 are forecast to be $252,000.

(xvii) **Integration Costs**

Pursuant to the Integration Agreement between NGTL and ATCO Gas and Pipelines Ltd. ("**ATCO Pipelines**"), NGTL will include ATCO Pipelines' Alberta Utilities Commission approved annual revenue requirement in NGTL's annual revenue requirement. Integration costs for 2013 are forecast to be $182,642,000.

2. **OTHER PROVISIONS**

(A) **Settlement Package**

The parties agree that regulatory approval of this Settlement in its entirety as a package is a requirement for the Settlement to be binding on any party. The terms and conditions of this Settlement do not set any precedent and does not prejudice any party in any position it may take regarding the matters addressed in this Settlement in other proceedings or forums.

(B) **Confidentiality**

All information exchanged in this Settlement process is confidential and is provided on a without prejudice basis. NGTL shall be entitled to file this Settlement with regulatory authorities and may disclose the terms and conditions of this Settlement as it determines necessary in a news release.

(C) **2014 and 2015 Interim Rates**

NGTL shall calculate interim rates, tolls, and charges based on the forecast revenue requirement or the previous year's approved revenue requirement, a forecast of firm transportation contract demand quantity and throughput, and the approved rate design in place at the time. On or before December 1 of each year, the interim rates, tolls, and charges to be effective January 1 of the following year will be provided to interested parties and filed with the NEB for approval.

(D) **Deferral Accounts**

NGTL will use the following deferral accounts for 2013 and 2014:

(i) **Revenue Deferral Account**

The Revenue Deferral Account will be used to capture:

(a) Variances in revenue resulting from actual Firm Transportation Contract Demand revenue differing from the forecast of Firm Transportation Contract Demand revenue used in establishing the applicable year's rates, including all variances related to all Firm Transportation services.

(b) Variances in revenues resulting from actual Interruptible Transportation Services revenue differing from the forecast of Interruptible Transportation Services revenue used in establishing the applicable year's rates, including all variances from interruptible receipt and interruptible delivery revenues net of Alternate Access, Facilities Connection Service, Pressure/Temperature Service and Other Services, and ATCO Pipeline Franchise Fees.

(ii) **CO_2 Management Service Deferral Account**

The CO_2 Management Service Deferral Account will be utilized to capture the variances between forecast and actual revenue and forecast and actual costs attributable to the CO_2 Management service in the applicable year. Any incentive earned by NGTL under the provisions of the CO_2 incentive mechanism will also be recorded in this account.

(iii) **Flow-Through Costs Deferral Account**

The Flow-Through Costs Deferral Account will be utilized to capture the variances between forecast and actual costs for all flow-through cost components of the revenue requirement with the exception of costs related to the CO_2 Management Service.

(E) **Accounting Matters**

(i) Support services costs not directly charged to capital projects will be capitalized. TransCanada's support services recovery rate for 2013 is forecast to be 30%.

(ii) Allowance for Funds Used During Construction ("**AFUDC**") and carrying charges will be calculated using the NGTL System weighted average cost of capital based on a deemed debt/equity ratio of 60%/40% and a return on equity of 10.1%.

(F) **Reporting**

(i) NGTL will seek exemption from the Toll Information Regulations, to allow it to file surveillance reports on an annual basis for the Term. Surveillance reports will be filed no later than 60 days following December 31.

(ii) On or before March 31 of the applicable year, NGTL will provide Supplemental Schedules to the Tolls, Tariff, Facilities, and Procedures Committee ("**TTFP**") as provided proforma in Appendix 3 (the "**Supplemental Schedules**").

(iii) During the Term, NGTL will provide annual updates to the TTFP on the Pipeline Integrity and compressor repair and overhaul activities and costs.

(iv) During the Term, NGTL will provide annual variance updates to the TTFP for facility projects forecast to be in excess of $50 million.

(v) Upon commencement of negotiations toward a settlement regarding the revenue requirement after the Term, NGTL will provide Supplemental Schedules for the base year, test year, and forecast years.

(G) **Regulatory or Legislative Changes**

Any cost variances due to any regulatory or legislative changes that were not known of or otherwise reasonably foreseeable to be incurred during the Term shall be treated as Flow-Through Costs.

(H) **Audit**

The TTFP may conduct an independent audit of this Settlement and will use reasonable efforts to complete it prior to July 1, 2015. The audit will verify compliance by NGTL with the terms of this Settlement and verify the validity of the information provided in the reporting packages. Subject to the execution of an acceptable confidentiality agreement by the auditor, NGTL will provide reasonable access to all necessary source data. The costs and expenses for the audit will be paid by NGTL and added to NGTL's revenue requirement for the subsequent year.

Appendix 1

SCHEDULE OF 2013 DEPRECIATION RATES

CATEGORY	ACCOUNT	DESCRIPTION	LATERAL SEGMENT DEPRECIATION RATE (%)	MAINLINE SEGMENT DEPRECIATION RATE (%)	COMPOSITE DEPRECIATION RATE (%)
Meter Stations					
	461.10	LAND RIGHTS	3.47%	2.58%	2.85%
	463.00	BUILDINGS	4.18%	3.45%	3.67%
	463.10/463.20	SITE	4.90%	4.26%	4.45%
	467.00	AUTOMATION	6.48%	5.35%	5.69%
	467.10	INSTRUMENTATION	8.84%	7.17%	7.67%
	467.20	PIPING	5.70%	4.56%	4.90%
	467.30	ELECTRICAL SYSTEM	4.51%	3.49%	3.79%
Compressor Stations					
	461.20	LAND RIGHTS	7.39%	3.74%	3.90%
	462.00	BUILDINGS	4.77%	2.46%	2.56%
	462.10	SITE	5.47%	2.86%	2.97%
	466.10	COMPRESSOR UNIT	10.02%	4.09%	4.30%
	466.20	PIPING	7.40%	3.56%	3.72%
	466.30	INSTRUMENTATION	16.50%	5.74%	6.19%
	466.40	ELECTRICAL SYSTEM	4.57%	2.19%	2.29%
	466.50	AUTOMATION	6.92%	3.68%	3.81%
	466.90	COMPRESSOR OVERHAUL	7.25%	7.25%	7.25%
Pipelines					
	461.00	LAND RIGHTS	1.35%	1.57%	1.54%
	465.10	PIPE	2.84%	2.52%	2.56%
	465.20	VALVES	2.88%	2.26%	2.35%
	468.00	COMMUNICATION STRUCT. & EQUIP.	6.57%	6.57%	6.57%
General Plant					
	482.10	BUILDINGS			3.52%
	483.10	OFFICE FURNITURE			7.60%
	483.20	OFFICE EQUIPMENT			6.70%
	483.40	COMPUTER HARDWARE			10.41%
	483.60	COMPUTER SOFTWARE			12.86%
	484.10	VEHICLES AND TRAILERS			7.61%
	485.00	HEAVY WORK EQUIPMENT			3.75%
	486.00	TOOLS AND WORK EQUIPMENT			1.89%
	488.00	MISCELLANEOUS EQUIPMENT			4.95%
	482.00	LEASEHOLD IMPROVEMENTS			10.84%
	482.20	TC NEW TOWER			4.37%

Appendix 2

SCHEDULE OF 2014 DEPRECIATION RATES

CATEGORY	ACCOUNT	DESCRIPTION	LATERAL SEGMENT DEPRECIATION RATE (%)	MAINLINE SEGMENT DEPRECIATION RATE (%)	COMPOSITE DEPRECIATION RATE (%)
Meter Stations					
	461.10	LAND RIGHTS	3.54%	2.63%	2.90%
	463.00	BUILDINGS	4.26%	3.51%	3.74%
	463.10/463.20	SITE	4.99%	4.34%	4.53%
	467.00	AUTOMATION	6.61%	5.46%	5.80%
	467.10	INSTRUMENTATION	9.01%	7.31%	7.82%
	467.20	PIPING	5.81%	4.65%	5.00%
	467.30	ELECTRICAL SYSTEM	4.59%	3.56%	3.87%
Compressor Stations					
	461.20	LAND RIGHTS	7.54%	3.82%	3.97%
	462.00	BUILDINGS	4.86%	2.51%	2.61%
	462.10	SITE	5.57%	2.91%	3.03%
	466.10	COMPRESSOR UNIT	10.21%	4.17%	4.38%
	466.20	PIPING	7.55%	3.63%	3.79%
	466.30	INSTRUMENTATION	16.82%	5.85%	6.31%
	466.40	ELECTRICAL SYSTEM	4.66%	2.23%	2.33%
	466.50	AUTOMATION	7.05%	3.75%	3.89%
	466.90	COMPRESSOR OVERHAUL	7.39%	7.39%	7.39%
Pipelines					
	461.00	LAND RIGHTS	1.38%	1.60%	1.57%
	465.10	PIPE	2.89%	2.57%	2.61%
	465.20	VALVES	2.93%	2.31%	2.40%
	468.00	COMMUNICATION STRUCT. & EQUIP.	6.70%	6.70%	6.70%
General Plant					
	482.10	BUILDINGS			3.52%
	483.10	OFFICE FURNITURE			7.60%
	483.20	OFFICE EQUIPMENT			6.70%
	483.40	COMPUTER HARDWARE			10.41%
	483.60	COMPUTER SOFTWARE			12.86%
	484.10	VEHICLES AND TRAILERS			7.61%
	485.00	HEAVY WORK EQUIPMENT			3.75%
	486.00	TOOLS AND WORK EQUIPMENT			1.89%
	488.00	MISCELLANEOUS EQUIPMENT			4.95%
	482.00	LEASEHOLD IMPROVEMENTS			10.84%
	482.20	TC NEW TOWER			4.37%

NOVA GAS TRANSMISSION LTD.

NGTL SYSTEM
2013 - 2014 REVENUE REQUIREMENT SETTLEMENT

SUPPLEMENTAL SCHEDULES

FOR THE YEAR ENDED DECEMBER 31, 201X

NOVA GAS TRANSMISSION LTD.

NGTL SYSTEM
2013 - 2014 REVENUE REQUIREMENT SETTLEMENT

SUPPLEMENTAL SCHEDULES

FOR THE YEAR ENDED DECEMBER 31, 201X

INDEX

REVENUE REQUIREMENT SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
1	Transportation by Others	
2	Pipeline Integrity Expense	
3	NEB Cost Recovery	
4	Return	
5	Income Taxes	
6	Depreciation	
7	Regulatory Proceeding Costs	
8	Emissions Compliance Costs	
9	Municipal and Other Taxes	
10	Regulatory Amortizations	
11	Compressor Repair Expense	
12	Operations, Maintenance and Administrative Costs	
13	Pension and Other Post Employment Benefits Actuarial Loss Amortization	
14	Uninsured Losses	
15	Annual Foreign Exchange Amortization Amount	
16	Foreign Exchange on Interest Payments	
17	CO_2 Management Service Costs	
18	Subtotal	
19	Integration Costs	
20	Total Revenue Reqirement	

AVERAGE RATE BASE SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
	Utility Investment	
1	Gross Plant	
2	Accumulated Depreciation	
3	Net Plant	
	Working Capital	
4	Cash	
5	Materials and Supplies	
6	Transmission Linepack	
7	Total Working Capital	
	Deferred Costs	
8	Prefunded / (Unfunded) Foreign Exchange on Long-term Debt	
9	Debt Discount & Expense	
10	Prefunded / (Unfunded) Pension and OPEB Liability	
11	Operating and Debt Service Deferrals	
12	Total Deferred Costs	
13	Total Rate Base	
14	GPUC	
15	Total Investment Base	

AVERAGE CAPITALIZATION AND OVERALL RATE OF RETURN
FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	SCH. REF.	AMOUNT ($000)	RATIO %	COST RATE %	COST COMPONENT %	COST AMOUNT $
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Debt - Funded	3.0.1					
2	Debt - Unfunded / (Prefunded)						
3	Total Debt						
4	Common Equity						
5	Total Capitalization and Rate of Return						
6	Rate Base						
7	GPUC						
8	Total Capitalization						

WEIGHTED AVERAGE COST OF LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 201X

($000)

LINE NO.	DESCRIPTION	INTEREST RATE %	PRINCIPAL OUTSTANDING	DAYS OUTSTANDING	TOTAL NGTL INTEREST	DISALLOWED INTEREST [(1)] %	DISALLOWED INTEREST [(1)]	ADJUSTED INTEREST
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Debentures							
1	11.2% Series 18							
2	11.2% Series 18							
3	12.20 % Series 20							
4	12.20 % Series 21							
5	9.9% Series 23							
6	7 7/8% U.S. $200MM							
7	7.7% U.S. $200MM							
	Medium Term Notes							
8	8.90% MTN #7							
9	8.90% MTN #8							
10	8 7/8% MTN #9							
11	8.46% MTN #11							
12	8.90% MTN #12							
13	8 7/8% MTN #13							
14	7.00% $100MM MTN #17							
15	7.00% $50MM MTN #18							
16	6.59% $20MM MTN #20							
17	6.59% $2.5MM MTN #21							
18	6.59% $10MM MTN #22							
19	6.59% $20MM MTN #23							
20	6.59% $25MM MTN #29							
21	6.30% $100MM MTN#31							
22	5.10% $300MM Note Payable to TransCanada							
23	5.05% $500MM Note Payable to TransCanada							
24	8.05% $400MM Note Payable to TransCanada							
25	4.55% $250MM Note Payable to TransCanada							
26	3.65% $200MM Note Payable to TransCanada							
27	3.10% $500MM Note Payable to TransCanada							
28	7.50% U.S. $32.5MM							
29	**Total Interest**							
30	Weighted Average (Schedule 3.2.4)							
31	Amortization of Issue Costs (Schedule 3.3.4)							
32	**Total Cost of Long Term Debt Outstanding**							
33	**Financing Cost Rate**							

[(1)] The effective interest rate on Series 20 and Series 21 debentures have both been reduced by 88 basis points. This adjustment has been made since Alberta Public Utilities Board order E92086.

WEIGHTED LONG-TERM DEBT OUTSTANDING

FOR THE YEAR ENDED DECEMBER 31, 201X

($000,000)

LINE NO.	DESCRIPTION	Jan 1	Jan 31	Feb 28	Mar 31	Apr 30	May 31	June 30	July 31	Aug 31	Sep 30	Oct 31	Nov 30	Dec 31	13 MONTH AVERAGE
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Debentures														
1	11.2% Series 18														
2	12.20 % Series 20														
3	12.20 % Series 21														
4	9.9% Series 23														
5	7 7/8% U.S. $200MM														
6	7.70% U.S. $200MM														
	Medium Term Notes														
7	8.90% MTN #7														
8	8.90% MTN #8														
9	8 7/8% MTN #9														
10	8.46% MTN #11														
11	8.90% MTN #12														
12	8 7/8% MTN #13														
13	7.00% $100MM MTN #17														
14	7.00% $50MM MTN #18														
15	6.59% $20MM MTN #20														
16	6.59% $2.5MM MTN #21														
17	6.59% $10MM MTN #22														
18	6.59% $20MM MTN #23														
19	6.59% $25MM MTN #29														
20	6.30% $100MM MTN#31														
21	5.10% $300MM Note Payable to TransCanada														
22	5.05% $500MM Note Payable to TransCanada														
23	8.05% $400MM Note Payable to TransCanada														
24	4.55% $250MM Note Payable to TransCanada														
25	3.65% $200MM Note Payable to TransCanada														
26	3.10% $500MM Note Payable to TransCanada														
27	7.50% U.S. $32.5MM														
28	**Total**														

AMORTIZATION OF LONG-TERM DEBT ISSUE EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	MATURITY YEAR	TOTAL ISSUE COSTS	UNAMORTIZED BALANCE DEC. 31, 2012	LESS: AMORTIZATION	UNAMORTIZED BALANCE DEC. 31, 2013
	(a)	(b)	(c)	(d)	(e)	(f)
	Debentures					
1	11.20% Series 18					
2	12.20% Series 21					
3	9.90% Series 23					
4	7.875% U.S. $200MM					
5	7.70% U.S. $200MM					
	Medium Term Notes					
6	8.9% MTN #7 and #8					
7	8.875% MTN #9 and 13					
8	8.46% MTN #11					
9	7.00% $100MM MTN #17					
10	6.59% $20MM MTN #20					
11	6.59% $2.5MM MTN #21					
12	6.59% $10MM MTN #22					
13	6.59% $20MM MTN #23					
14	6.59% $25MM MTN #29					
15	6.30% $100MM MTN#31					
16	5.10% $300MM Note Payable to TransCanada					
17	5.05% $500MM Note Payable to TransCanada					
18	8.05% $400MM Note Payable to TransCanada					
19	4.55% $250MM Note Payable to TransCanada					
20	3.65% $200MM Note Payable to TransCanada					
21	3.10% $500MM Note Payable to TransCanada					
22	7.50% U.S. $32.5 MM					
23	**Total**					

SCHEDULE OF FLOW-THROUGH INCOME TAXES

FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	SCH. REF.	ACTUAL
	(a)	(b)	(c)
1	Return on Equity	3.0	
	Add:		
2	Depreciation	5.0	
3	Non-allowed Amortization of Debt Discount & Expense	3.0.3	
4	Annual Foreign Exchange Amortization Amount	8.0	
5	Non-allowed Meals and Entertainment		
6	Sub-total		
	Deduct:		
7	Capital Cost Allowance	4.0.1	
8	Cumulative Eligible Capital	4.0.1	
9	Capitalized Repair & Overhaul Costs	4.0.1	
10	Interest AFUDC		
11	Issue Costs		
12	Site Remediation Costs	4.0.1	
13	Sub-total		
14	Total Taxable Amount		
15	Taxes thereon (Tax Rate / (1-Tax Rate))		
16	Utility Income Tax Requirement		

SCHEDULE OF CAPITAL COST ALLOWANCE
FOR THE YEAR ENDED DECEMBER 31, 201X
($000'S)

LINE NO.	CLASS	UNDEPRECIATED CAPITAL COST OPENING BALANCE	ADDITIONS (NET)	BALANCE BEFORE CLAIM	MAXIMUM CCA	CLOSING BALANCE
	(a)	(b)	(c)	(d)	(e)	(f)
1	Class 1 - Full (4%)					
2	- Half Year					
3	Class 2 - Full (6%)					
4	Class 3 - Full (5%)					
5	- Half Year					
6	Class 6 - (10%)					
7	Class 7 - Full (15%)					
8	- Half Year					
9	Class 8 - Full (20%)					
10	- Half Year					
11	Class 10 - Full (30%)					
12	- Half Year					
13	Class 10a - Full (45%)					
14	Class 10b - Full (55%)					
15	- Half Year					
16	Class 12 - Full (100%)					
17	- Half Year					
18	Class 13 - Full (S/L)					
19	- Half Year					
20	Class 17 - Full (S/L)					
21	Class 49 - Full (8%)					
22	- Half Year					
23	TOTAL					

CAPITAL COST ALLOWANCE RECONCILIATION
($000's)

LINE NO.	PARTICULARS	CLOSING BALANCE
1	Transfers to GPIS (including Overhead, excluding AFUDC)	
2	Regulated General Plant Additions in 2013	
	Adjustments	
3	Compressor Overhaul Capitalized	
4	Net Proceeds - Retirements	
5	Site Remediation & Environmental costs	
6	Total Adjustments	
7	Capital Cost Allowance Additions per Line 23 above	

INCOME TAX EXPENSE SCHEDULE

FOR THE YEAR ENDED DECEMBER 31, 201X

($000'S)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
	CALCULATION OF ELIGIBLE CAPITAL EXPENSES	
1	Unamortized Balance at January 1, 2013	
2	Additions - Land Rights (@75%)	
3	Balance at December 31, 2013	
4	Amount Available for Tax Deduction at 7% of Line 3	
5	Unamortized Balance at January 1, 2014	

DEPRECIATION

FOR THE YEAR ENDED DECEMBER 31, 201X
($000 unless otherwise noted)

LINE NO.	DESCRIPTION	ACTUAL RATE	ACTUAL EXPENSE
	(a)	(b)	(c)
1	Land Rights		
2	Mains		
3	Compressor		
4	Measuring and Regulating		
5	CO_2 Service		
6	Communication Structure & Equipment - Transmission		
7	Structures & Improvements		
8	Furniture & Equip - General		
9	Furniture & Equip - Computers		
10	Vehicles		
11	Heavy Work Equipment		
12	Tools & Work Equipment		
13	Miscellaneous Equipment - General		
14	Total Depreciation Expense		

TRANSPORTATION BY OTHERS

FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
1	Foothills Pipe Lines	
2	TransCanada Pipeline Ventures	
3	Other	
4	Total Transportation by Others	

FOREIGN EXCHANGE ON INTEREST PAYMENTS

FOR THE YEAR ENDED DECEMBER 31, 201X
($000s)

LINE NO.	DESCRIPTION	DEBT ISSUE (US$)	INTEREST RATE	DATE OF INTEREST PAYMENT	INTEREST PAYMENTS (US$)	HISTORICAL EXCHANGE RATE [1]	FORECAST EXCHANGE RATE	FORECAST (GAIN) / LOSS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	7.50% MTN #5							
2	7.875% U.S. $200 mm							
3	7.70% U.S. $50 mm							
4	7.70% U.S. $150 mm							
5	7.50% MTN #5							
6	7.875% U.S. $200 mm							
7	7.70% U.S. $50 mm							
8	7.70% U.S. $150 mm							
9	Total foreign exchange (gain) / loss on interest payments							

[1] Historical exchange rates pertain to the original financing when a maturing issue(s) is rolled into a new issue.

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	MATURITY DATE	AMOUNT (US$)	HISTORICAL EXCHANGE RATE	DEC 31, 2012 EXCHANGE RATE	CURRENT YEAR LOSS/(GAIN)
	(a)	(b)	(c)	(d)	(e)	(f)
1	7.875% US$200MM					
2	7.70% US$150MM Note Payable to TCPL					
3	7.70% US$50MM Note Payable to TCPL					
4	7.50% Medium Term Note - US$32.5MM					
5						
6	Prefunded / (Unfunded) Foreign Exchange on Long Term Debt Balance at January 1, 2013					
7	**Total**					
8	Annual Foreign Exchange Amortization Amount (Line 6 divided by 16) [2]					

[1] Represents the number of years remaining until the last USD debt instrument matures.

GPIS and GPUC CONTINUITY SUMMARY

FOR THE YEAR ENDED DECEMBER 31, 201X
($000)

LINE NO.	DESCRIPTION	ACTUAL
	(a)	(b)
	Gas Plant In Service	
1	Opening Gas Plant In Service	
2	GPIS Transfers	
3	General Plant Additions	
4	Retirements	
5	Closing Gas Plant In Service	
6	Opening Accumulated Depreciation	
7	Depreciation Expense	
8	Retirements	
9	Closing Accumulated Depreciation	
10	Retirements In Progress	
11	Closing Net Gas Plant In Service	
	Gas Plant Under Construction	
12	Opening Gas Plant Under Construction	
13	Capital Expenditures	
14	AFUDC	
15	GPIS Transfers	
16	Closing Gas Plant Under Construction	