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BY ELECTRONIC FILING & COURIER February 18, 2004
File No.: 015656.1009

Mr. Michel L. Mantha
Secretary
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Dear Mr. Mantha:

**Re: TransCanada PipeLines Limited (TransCanada)
2004 Mainline Tolls and Tariff Application (Application)
Board File No. 4200-T001-23**

The TransCanada Application was filed on January 26, 2004 with the National Energy Board (Board) under cover of a letter that indicated that TransCanada expected to update the filing to include 2003 actual data by mid-February.

Now enclosed for filing is one copy of the TransCanada February 2004 Update to the Application (February Update). The February Update reflects 2003 actual data, the impact of 2003 actual results on certain 2004 test year amounts, and other changes based on current information.

In accordance with the *National Energy Board Rules of Practice and Procedure, 1995*, the amended pages contained in the February Update are dated and marked to indicate the amendments. Explanations are provided where required. To assist the Board and interested parties, TransCanada has also included a summary of changes to the 2003 and 2004 information.

TransCanada is filing the February Update electronically by placing it in the electronic filing repository of the Board, and will notify parties to the RH-1-2002 and RH-4-2001 proceedings, the Tolls Task Force and its customers of the filing.

CALGARY
VANCOUVER
TORONTO
MONTREAL
OTTAWA
NEW YORK
LONDON
HONG KONG
SYDNEY

Should the Board require additional information with respect to the application, please contact me or Céline Bélanger, Vice President, Regulatory Services, TransCanada PipeLines Limited (403-920-7184).

Yours very truly,

for C. KEMM YATES

CKY/mjb
Enclosure
cc: RH-1-2002 Interested Parties (by fax)
RH-4-2001 Interested Parties (by fax)
TransCanada Tolls Task Force (on-line notification)
TransCanada Mainline Customers (by fax)

UPDATE TO 2004 TOLLS AND TARIFF APPLICATION
SUMMARY OF CHANGES

VOLUME 1

Volume 1 of the Application has been revised to include 2003 actual data and 2004 updates for the following:
Application
TAB A - Introduction and Executive Summary
TAB C - Fuel Gas Incentive Program
Written Evidence
Attachment 1 pages 2 of 3 and 3 of 3
Attachment 3 pages 1 through 4
TAB D - Services
Attachment D-2

VOLUME 2

2003 ACTUAL YEAR

The 2003 Revenue Requirement, including Rate Base and Rate of Return sections of the Application have been updated to reflect actual data for 2003.

Changes to individual components are noted below.

SCHEDULE REFERENCE		FILED JANUARY 2004	REVISED FEBRUARY 2004
		($ 000)	($ 000)
REVENUE REQUIREMENT			
Schedule 1.2 (and supporting schedules)			
Line 1	Transmission By Others	359,878	360,015
Line 2	Storage Operating Costs	11,457	11,371
Line 3	Pipeline Integrity and Ins. Deductible Costs	44,566	45,200
Line 5	Return	790,149	789,692
Line 6	Income Taxes	188,591	184,030
Line 7	Depreciation	420,577	419,834
Line 9	Gas Related and Electric Costs	78,927	72,847
Line 10	Municipal and Provincial Capital Taxes	115,701	115,741
Line 13	Operations, Maintenance and Administrative (OM&A)	231,730	228,107
Line 15	Regulatory Proceeding Costs	2,860	2,490
Line 18	Non Discretionary Miscellaneous Revenue	(65,821)	(66,117)
Line 19	Discretionary Miscellaneous Revenue	(248,314)	(251,794)
RATE BASE			
Schedule 5.2 (and supporting schedules)			
Line 17	Total Rate Base	8,560,659	8,555,713
Line 18	Return	790,149	789,692

UPDATE TO 2004 TOLLS AND TARIFF APPLICATION
SUMMARY OF CHANGES

2004 TEST YEAR

The 2004 Revenue Requirement and associated schedules and explanatories have been updated to reflect the following changes:

Insurance Deductible - updated to reflect actual costs impacting amounts to be amortized in 2004
Regulatory Amortizations - updated to reflect actual 2003 deferred balances
NEB Cost Recovery - updated to reflect the NEB's January 5, 2004 Final Notice of the 2004 Cost Recovery
OM&A Costs - updated to reflect actuarial adjustments to pension expense, revised estimates for long-term incentive compensation and adjustments to cost allocations
Rate Base - updated to reflect 2004 opening balance changes resulting from actual 2003 closing balances
Return and Depreciation - updated to reflect the noted changes to Rate Base
Income Tax - updated to reflect actual salaries by province, an increase in the Ontario tax rate from 11% to 14% and impacts to common equity return associated with the changes to rate base
Municipal and Provincial Capital Tax - updated to reflect an increase in Ontario capital tax rate from 0.27% to 0.30%
Rate of Return - total capitalization, ratios and cost components updated to reflect actual closing capitalization balances for 2003

SCHEDULE REFERENCE		FILED JANUARY 2004	REVISED FEBRUARY 2004
		($ 000)	($ 000)
REVENUE REQUIREMENT			
Schedule 1.3 (and supporting schedules)			
Line 3	Pipeline Integrity and Ins. Deductible Costs	31,686	31,710
Line 4	NEB Cost Recovery	12,732	12,785
Line 5	Return	781,974	780,075
Line 6	Income Taxes	211,770	217,412
Line 7	Depreciation	416,763	415,160
Line 10	Municipal and Provincial Capital Taxes	118,449	118,772
Line 11	Regulatory Amortizations	(51,166)	(68,526)
Line 12	Operations, Maintenance and Administrative (OM&A)	212,678	215,398
Line 16	Pressure Charges	4,563	4,526
Line 18	Non Discretionary Miscellaneous Revenue	(71,128)	(70,536)
Line 19	Discretionary Miscellaneous Revenue	(308,513)	(279,735)
RATE BASE			
Schedule 5.3 (and supporting schedules)			
Line 17	Total Rate Base	8,214,016	8,202,682
Line 18	Return	781,974	780,075
Rate of Return			
Schedule 1.3	Total Capitalization	8,216,080	8,206,519
Schedule 1.3	Rate of Return on Rate Base	9.52%	9.51%

UPDATE TO 2004 TOLLS AND TARIFF APPLICATION
SUMMARY OF CHANGES

2004 TEST YEAR

TOLL DESIGN

All schedules have been updated to reflect the noted changes in the Revenue Requirement. Changes to allocation units are as follows:

Contract Changes	GJ
New FT Contracts - long haul	182,724
FT Non-Renewals -long haul	(10,062)
Non-Renewals -short haul	(31,213)
Total Change	141,449

Contract shifts included the following:
Union SSMDA to Union NDA 8,862 GJ
Cornwall to Iroquois 9,010 GJ

Multiple Handshake/Pooling Service is now a feature of FT service pursuant to TTF Resolution 07.2003. There is no longer a commodity toll for this service.
Lower discretionary revenue due to the increase in FT contract levels.
Lower non-discretionary revenue for Storage Transportation Service and Long-Term Winter Firm Service due to the change in system average unit costs resulting from the noted changes to the 2004 Revenue Requirement. Delivery Pressure Revenue changed reflecting changes to 2004 FT contracts, 2003 actual Delivery Pressure Revenue deferral account balances and changes in 2004 operating costs. There were no changes to Sales Meter Station charges.

	FILED JANUARY 2004	REVISED FEBRUARY 2004
Eastern Zone Toll	$1.21151	$1.21141

PART X REQUIREMENTS

Section 20 Plant Additions and Retirements
Sections 26-27 Financial Statements

TRANSCANADA PIPELINES LIMITED
2004 MAINLINE TOLLS AND TARIFF APPLICATION

INDEX

Tab B-7 Written Evidence of A. Lawrence Kolbe (The Brattle Group, Cambridge, MA) on Fair Return

Tab B-8 Written Evidence of Michael J. Vilbert (The Brattle Group, Cambridge, MA) on Fair Return

C. Fuel Gas Incentive Program

D. Services

VOLUME 2

Revenue Requirement

Tab 1	Schedules 1.1 to 1.3	Revenue Requirement for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 2	Schedules 2.1 to 2.3	Transmission by Others for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 3	Schedules 3.1 to 3.3	Storage Operating Costs for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 4	Schedule 4.0	Pipeline Integrity and Insurance Deductible Costs for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 5	Schedules 5.1 to 5.3	Rate Base for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 6	Schedules 6.1 to 6.3	Income Taxes for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 7	Schedules 7.1 to 7.3	Depreciation Expense for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 8	Schedule 8.0	Inventory Management Program for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004

Tab 9	Schedules 9.1 to 9.3	Gas-related and Electric Costs for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 10	Schedule 10.0	Municipal and Provincial Capital Taxes for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 11	Schedules 11.1 to 11.4	Regulatory Amortizations for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 12	Schedule 12.0	Storage Gas Gains or Losses for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 13	Schedules 13.0 to 13.18	Operations, Maintenance and Administrative Costs for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 14	Schedules 14.0 to 14.3	Compensation, Benefits and Staffing for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 15	Schedules 15.1 to 15.3	Debt Redemption Costs/(Gains) for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003, and Test Year Ending December 31, 2004
Tab 16	Schedule 16.0	Regulatory Proceeding Costs for the Base Year Ended December 31, 2002, Actual Year Ended December 31, 2003 and Test Year Ending December 31, 2004

Rate of Return

Schedules 1.1 to 4.1	Deemed Average Capitalization and Overall Rate of Return and Supporting Schedules for the Base Year Ended December 31, 2002.
Schedules 1.2 to 4.2	Deemed Average Capitalization and Overall Rate of Return and Supporting Schedules for the Actual Year Endend December 31, 2003.
Schedules 1.3 to 4.3	Deemed Average Capitalization and Overall Rate of Return and Supporting Schedules for the Test Year Ending December 31, 2004.

Toll Design

	Schedule 4.4	Miscellaneous Revenue: Long Term Winter Firm Service Revenue for the Test Year Ending December 31, 2004
	Schedule 4.5	Miscellaneous Revenue: Discretionary Services
	Schedule 4.6	Miscellaneous Revenue: Enhanced Capacity Release (ECR) Surcharge for the Test Year Ending December 31, 2004
Tab 5	Schedule 5.1	Proposed Tolls Effective January 1, 2004, for the Test Year Ending December 31, 2004
	Schedule 5.2	Interruptible Transportation Bid Floor Tolls Effective January 1, 2004, for the Test Year Ending December 31, 2004

Part X Requirements, Guidelines for Filing Requirements

- Summary of Part X Requirements/Location in Application

Part X Requirements contained in this section:

- s. 19 – Lead Lag
- s. 20 – Plant Additions and Retirements
- s. 26 - 27– Financial Statement Information
- s. 29 – Annual Report
- s. 33 – Debt Issues
- s. 35 – Yields
- s. 36 – Bond Rating Reports
- s. 39 – Common Shares
- s. 40 – Common Equity
- s. 44 – Foreign Exchange
- s. 46 – System Operations

2004 Mainline Tolls and Tariff Application
February 2004 Update

APPLICATION

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act*, R.S.C. 1985, c. N-7, as amended, (*Act)* and the Regulations made thereunder ; and

IN THE MATTER OF an Application by TransCanada PipeLines Limited pursuant to Part IV of the *Act* for approval of 2004 tolls.

TRANSCANADA PIPELINES LIMITED

2004 MAINLINE TOLLS AND TARIFF APPLICATION

January 2004

REVISED February 2004

To: The Secretary
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Introduction

1. TransCanada PipeLines Limited (TransCanada, TCPL or the Company) applies to the National Energy Board (Board or NEB) under Part IV of the *Act* for orders fixing and approving tolls that TransCanada shall charge for transportation services on its Mainline provided between January 1, 2004 and December 31, 2004.

2. In support of its 2004 Tolls and Tariff Application (Application), TransCanada provides and relies on the information in this Application, including the attached appendices, schedules and explanatories, and any additional information that TCPL may file, as directed or permitted by the Board.

3. The Application does not reflect the settlement of any elements of TransCanada's 2004 tolls and tariff.

Background

4. TransCanada is a federally incorporated Canadian corporation and a "company" as that term is defined in the *Act*.

5. TransCanada owns and operates a high-pressure natural gas transmission system that extends from the Alberta border across Saskatchewan, Manitoba, and Ontario, through a portion of Québec, and connects to various downstream Canadian and international pipelines (Mainline).

6. TransCanada is presently charging interim tolls in respect of 2004 pursuant to Board Order TGI-07-2003 issued December 18, 2003.

Applicable Time Periods

7. TransCanada has used the following time periods for the calculation of tolls in this Application:

Base Year: actual values from 1 January 2001 to 31 December 2002;

Actual Year: actual values from 1 January 2003 to 31 December 2003; and

Test Year: forecast values from 1 January 2004 to 31 December 2004.

2004 Rate Base and Revenue Requirement

8. The Average Rate Base for the 2004 Test Year is $8,202.7 million.

9. The Net Revenue Requirement for the 2004 Test Year is $1,781.4 million.

10. TransCanada seeks approval of a fair return for 2004 that reflects a rate of return on common equity of 11% on a deemed common equity ratio of 40% (After Tax Weighted Average Cost of Capital of 6.9%)**,** and an average cost of funded debt of 8.73%. The evidence supporting the fair return request is contained in Appendix B of the Application.

Fuel Gas Incentive Program

11. TransCanada proposes to continue the 2003 Fuel Gas Incentive Program with modifications in 2004.

12. The details of the 2004 Fuel Gas Incentive Program are described in Appendix C of the Application. TransCanada believes the merits of the program that accrued to shippers and the Company in 2001-2002 and 2003 remain relevant and appropriate factors which support continuing the program in 2004.

Service Proposals

13. TransCanada proposes to establish a new Non-Renewable Firm Transportation service (FT-NR) and proposes modifications to its existing Short-Term Firm Transportation service (STFT). The details of these proposals and associated tariff changes are discussed in Appendix D of the Application.

14. TransCanada believes the new FT-NR service and modifications to STFT service will provide shippers with access to a broader continuum of services and more options to optimize their transportation portfolios, and will also provide the opportunity to increase system revenues.

Deferral Accounts

15. TransCanada seeks to establish for the 2004 Test Year certain flow-through and incentive-based deferral accounts. The requested deferral accounts are listed in Volume 2, Schedule 11.4 of the Application.

16. In establishing the proposed 2004 tolls, TransCanada included actual 2003 deferral account balances in the 2004 Test Year Net Revenue Requirement.

Guidelines for Filing Requirements – Part X

17. TransCanada has complied with the Part X requirements of the Board's *Guidelines for Filing Requirements*. A concordance table is provided under Tab Part X Requirements.

Relief Requested

18. TransCanada requests from the Board an Order:

    (a) fixing and approving tolls in accordance with this Application for the 2004 Test Year for Mainline services provided from January 1, 2004 to December 31, 2004;

    (b) approving the methodology utilized by TransCanada to determine the 2004 Test Year Net Revenue Requirement and the resulting 2004 tolls;

    (c) approving the Fuel Gas Incentive Program proposal for 2004;

(d) approving the proposed FT-NR service and proposed modifications to STFT service and associated tariff changes;

(e) establishing the deferral accounts itemized in Volume 2, Schedule 11.4 of the Application for the period January 1, 2004 to December 31, 2004;

(f) allowing TransCanada to include in the 2005 Test Year Revenue Requirement variances between the forecasted and final amounts in the 2003 Forecast Year deferral accounts; and

(g) granting such further and other relief as TransCanada may request or the Board may determine to be appropriate.

Respectfully submitted.

Calgary, Alberta
January 26, 2004

TransCanada PipeLines Limited

Per: ______________________________
Céline Bélanger
Vice President, Regulatory Services

Communications relating to this Application should be directed to:

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Vice President, Regulatory Services
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Email: celine_belanger@transcanada.com

and to

C. Kemm Yates, Q.C.
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Email: kyates@stikeman.com

2004 Mainline Tolls and Tariff Application
February 2004 Update

APPENDIX A:
INTRODUCTION AND EXECUTIVE SUMMARY

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act*, R.S.C. 1985, c. N-7, as amended, (*Act)* and the Regulations made thereunder ; and

IN THE MATTER OF an Application by TransCanada PipeLines Limited (TransCanada) pursuant to Part IV of the *Act* for approval of 2004 tolls.

INTRODUCTION AND EXECUTIVE SUMMARY

January 2004

REVISED February 2004

Q1. What is TransCanada requesting in this Application?

A1. TransCanada seeks approval from the National Energy Board (NEB or the Board) for tolls on its Mainline system for the period January 1 to December 31, 2004. The application includes requests for a change in the Mainline's allowed fair return , continuation of the 2003 Fuel Gas Incentive Program with modifications, and the establishment of a new firm transportation service and modifications to its existing Short Term Firm Transportation service (STFT). The application also requests approval of the 2004 proposed rate base, return on rate base and other revenue requirement components.

Q2. What are the changes being proposed by TransCanada to the Mainline's fair return?

A2. TransCanada's Mainline 2004 Revenue Requirement includes an overall rate of return on rate base of 9.51 percent that incorporates a proposed rate of return on common equity of 11 percent on a deemed common equity ratio of 40 percent (After Tax Weighted Average Cost of Capital of 6.9 percent). TransCanada is further proposing the redemption of the US$ 460 million 8.25% Junior Subordinated Debentures (JSD) and the US$ 200 million 8.50% Debentures in July 2004. In July 2003, TransCanada redeemed the US $160 million 8.75% JSD.

The combined JSD securities, first introduced into the Mainline's capital structure in 1998, have comprised approximately 10 percent of the Mainline's total capitalization in the form of preferred securities. TransCanada is proposing to replace this 10 percent preferred component of its capitalization with 7 percent unfunded debt and 3 percent common equity. This mixture will provide approximately the same degree of credit support as has traditionally been provided by the preferred securities at a similar cost to shippers.

Details supporting the Company's evidence for these proposals are contained in Volume 1, Appendix B and Volume 2, Tab Rate of Return.

Q3. Why is TransCanada proposing to continue the Fuel Gas Incentive Program and are there any changes to the program being proposed in 2004?

A3**.** TransCanada is proposing to continue the 2003 Fuel Gas Incentive Program based on the benefits that accrued to shippers and TransCanada in the preceding programs in 2001-2002 and 2003. The merits of the program and the findings discussed by the Board in its RH-1-2002 Decision remain relevant and appropriate factors which support continuing the Fuel Gas Incentive Program in 2004.

Proposed changes to the program in 2004 include the calculation of fuel volumes saved based on actual fuel volume net of adjustments, target equations reflecting physical system changes since November 2001, the effective re-basing of target equations to 2001/02 and 2002/03 operating conditions, and revisions to the incentive schedule reflecting the new target equations. Details of the proposal are contained in Volume 1, Appendix C.

Q4. What other incentive programs are included in this application?

A4. TransCanada is required by the terms of the Mainline Service and Pricing Settlement (Settlement), dated April 2001 and approved by the NEB in September 2001, to continue certain incentive programs that survived the expiration of the Settlement at December 31, 2002. They are:

Severance Program

Pursuant to the Severance Program contained in Article 5 of the Settlement, the sharing of severance benefits will continue for the Test Years 2003 and 2004.

Accordingly, TransCanada has reflected the results of this program in its OM&A forecast total for 2004 contained in Volume 2, Tab 13.

Foreign Exchange and Interest Rate Management Programs

The Foreign Exchange Management Program and the Interest Rate Management Program, contained in Articles 10.2 and 10.3 of the Settlement, respectively, expired at December 31, 2002. In accordance with the Settlement, TransCanada agreed that it would continue to manage any positions outstanding at the end of the programs until maturity and that gains or losses from outstanding positions would be settled annually in accordance with Articles 10.2(a) and 10.3(a), respectively.

The final outstanding position under the Foreign Exchange Management Program was settled in May 2003. Outstanding positions under the Interest Rate Management Program extend to October 2009.

Q5. What is TransCanada proposing in this application regarding Mainline services?

A5. TransCanada is proposing the establishment of a new Non-Renewable Firm Transportation service (FT-NR) and modifications to its existing STFT service that will provide shippers with access to a broader continuum of services.

The proposed FT-NR service is targeted to shippers which require contract terms for one year or more depending on blocks of available capacity. FT-NR provides firm priority of service and flexibility to manage contract term risks through assignments and diversions. FT-NR is also biddable with a minimum price based on the 100% load factor FT toll.

Modifications to STFT service include expanding the contract term from seven days up to a term of one year less a day. In addition, TransCanada is proposing the elimination of the existing STFT bid price ceiling. The modified STFT service offers the same priority as firm service but does not include the flexibility features of assignments and diversions provided by FT-NR.

The new FT-NR service and STFT modifications are complementary in that they provide shippers with more options to optimize their transportation portfolios. Details supporting the Company's rationale for offering these proposals are contained in Volume 1, Appendix D.

Q6. What is TransCanada's estimate of Operations, Maintenance and Administrative (OM&A) costs in 2004?

A6. OM&A costs for 2004 are estimated to be $212.3 million. This amount excludes $3.1 million of Severance Program costs pursuant to the 2001 and 2002 Service and Pricing Settlement. The amortization of costs and benefits under this program expires at the end of 2004.

The presentation of OM&A cost schedules in this Application have been revised from those filed in the 2003 Mainline Tolls and Tariffs Application, and reflect input from Board staff and representatives of the Canadian Association of Petroleum Producers (CAPP). In its letter of November 13, 2003, the Board acknowledged the results of the discussions between TransCanada, Board Staff and CAPP. Details of OM&A costs are provided in Volume 2, Revenue Requirement Tabs 13 and 14.

Q7. What is TransCanada including in its 2004 Revenue Requirement for deferral account balances accumulated in 2003?

A7. Actual balances for 2003 Flow-Through and Incentive based deferral accounts, totaling a credit of $68.5 million, have been included in the 2004 Revenue Requirement for toll making purposes. The balances include actual results to December 31, 2003. Details of the 2003 deferred balances along with the request for deferral accounts in the 2004 Test Year are provided in Volume 2, Revenue Requirement Tab 11.

Q8. How do TransCanada's revenue requirements, rate base and overall rate of return compare for the 2002 Base Year, the 2003 Actual Year and the 2004 Test Year?

A8. Executive Summary Schedules 1.0 through 4.0 provide comparisons of TransCanada's revenue requirements, rate base, overall rate of return and OM&A cost for the 2002 Base Year, the 2003 Actual Year and the 2004 Test Year. Schedule 5.0 presents the tolls proposed for the 2004 Test Year.

Schedule 1.0

Schedule 1.0 provides a comparison of Gross and Net Revenue Requirements for the Base Year ended December 31, 2002, the Actual Year ended December 31, 2003 and the Test Year ending December 31, 2004.

The Net Revenue Requirement between 2003 and 2004 results in a decrease of $92.2 million. Major changes contributing to this decrease are increases in Miscellaneous Revenue of $32.4 million and cost decreases associated with Transmission by Others, Pipeline Integrity, Gas Related and Electric costs and OM&A costs of $36.4 million. Net gains associated with the redemption of the US$ 8.25% JSD and the US$ 8.50% Debentures result in a further reduction of $47.4 million.

Overall rate of return on rate base decreases by $9.6 million. Included in this decrease is a lower amount of return associated with a decline in rate base in 2004 and reduced interest and foreign exchange costs associated with the debt redemptions and an anticipated strengthening of the Canadian dollar relative to the US dollar. These combined decreases in return are partially offset by an increase in common equity return associated with the proposed changes to the rate of return on common equity and the deemed common equity component of the Mainline's capital structure.

Income Taxes increase by $33.4 million principally due to the proposed changes to overall common equity return and lower tax deductions in 2004 for site remediation costs. This increase is partially offset by a reduction in taxes associated with the forecast of net gains on the redemption of US dollar debt.

Schedule 2.0

Schedule 2.0 provides a comparison of the Average Rate Base for the Base Year ended December 31, 2002, the Actual Year ended December 31, 2003 and the Test Year ending December 31, 2004.

The Rate Base reduction from 2003 to 2004 is principally due to the increase in accumulated depreciation.

Schedule 3.0

Schedule 3.0 provides a comparison of Rate of Return and Total Capitalization for the Base Year ended December 31, 2002, the Actual Year ended December 31, 2003 and the Test Year ending December 31, 2004. The increase from 2003 to 2004 in the rate of return on Rate Base reflects the proposed increases in common equity return and decreases associated with the redemption of the US$ 8.25% JSD and the US$ 8.50% Debentures in July 2004 and lower foreign exchange costs on foreign debt interest due to the anticipated strengthening of the Canadian dollar relative to the US dollar.

Schedule 4.0

Schedule 4.0 provides a comparative summary of OM&A cost for the Base Year ended December 31, 2002, the Actual Year ended December 31, 2003 and the Test Year ending December 31, 2004.

OM&A costs have decreased from 2003 to 2004 principally due to lower program costs for compressor unit repair and overhaul maintenance and decreases in information system costs.

Schedule 5.0

Schedule 5.0 provides the requested 2004 Firm Transportation Service Canadian and export tolls. Allocation units are based on known contracts at January 19, 2004 and reflect new contracts associated with open seasons conducted in September and October 2003 and January 2004 and other new firm service requirements.

The 2004 Eastern Zone toll of $1.21 has increased over the 2003 interim toll of $1.19 primarily due to the annual impact in 2004 of non-renewed firm capacity in 2003. This increase is partially offset by the reduction in the 2004 Net Revenue Requirement.

Detailed Revenue Requirement, Rate of Return, Rate Base and Toll Design schedules for all years are provided under the respective tabs in Volume 2.

Q9. What is the current status of revenue requirements, rate base and overall rate of return for the 2002 Base Year and the 2003 Actual Year?

A9. TransCanada applied to the Board for review and variance of the RH-4-2001 Decision in which the Board determined the rate of return on common equity and the deemed capital structure for the Mainline for 2001 and 2002. The dismissal of TransCanada's review and variance application is subject to an appeal by TransCanada to the Federal Court of Appeal which will be heard in mid February 2004 with a decision to follow an indeterminate time thereafter.

In the RH-1-2002 Decision, the Board determined that Mainline tolls for 2003 should remain interim pending the results of TransCanada's appeal.

Q10. Does that conclude this Introduction and Executive Summary?

A10. Yes.

COMPARATIVE REVENUE REQUIREMENTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002
ACTUAL YEAR ENDED DECEMBER 31, 2003 AND
TEST YEAR ENDING DECEMBER 31, 2004
(AMOUNT $000)

LINE NO.	PARTICULARS	Base Year 2002	Adjustments	Actual 2003		Adjustments	Test Year 2004	
	(a)	(b)	(c)	(d)		(e)	(f)	
1	Transmission By Others	385,159	(25,144)	360,015	I	(4,618)	355,397	
2	Storage Costs	10,956	415	11,371	I	805	12,176	
3	Pipeline Integrity and Insurance Deductible Costs	25,861	19,339	45,200	I	(13,490)	31,710	I
4	MCBA Compliance Audit	4	(4)	0		0	0	
5	NEB Cost Recovery	7,728	3,004	10,732		2,053	12,785	I
6	Return	821,643	(31,951)	789,692	I	(9,617)	780,075	I
7	Income Taxes	153,765	30,265	184,030	I	33,382	217,412	I
8	Depreciation	362,274	57,560	419,834	I	(4,674)	415,160	I
9	Inventory Management Program	12,000	0	12,000		(4,000)	8,000	
10	Gas Related and Electric Costs	53,427	19,420	72,847	I	(5,570)	67,277	
11	Municipal and Provincial Capital Taxes	115,848	(107)	115,741	I	3,031	118,772	I
12	Regulatory Amortizations	(100,107)	30,966	(69,141)		615	(68,526)	I
13	Gain on Sale of Storage Gas	(512)	(441)	(953)		953	0	
14	Operations, Maintenance & Administrative	205,974	22,133	228,107	I	(12,709)	215,398	I
15	Debt Redemption Costs / (Gains)	0	5,788	5,788		(47,389)	(41,601)	
16	Regulatory Proceeding Costs	3,858	(1,368)	2,490	I	610	3,100	
17	Pressure Charges	4,625	(853)	3,772		754	4,526	I
18	Gross Revenue Requirement	2,062,503	129,022	2,191,525	I	(59,864)	2,131,661	I
	Miscellaneous Revenue							
19	Non Discretionary Miscellaneous Revenue	(74,402)	8,285	(66,117)	I	(4,419)	(70,536)	I
20	Discretionary Miscellaneous Revenue	(96,216)	(155,578)	(251,794)	I	(27,941)	(279,735)	I
21	Total Miscellaneous Revenue	(170,618)	(147,293)	(317,911)	I	(32,360)	(350,271)	I
22	Net Revenue Requirement	1,891,885	(18,271)	1,873,614	I	(92,224)	1,781,390	I

I Updated to reflect 2003 actual costs.
I Updated to reflect the impact of 2003 actuals on opening balances for 2004, the Board's Final Notice for 2004 NEB Cost Recovery, and adjustments to insurance deductible, regulatory amortizations, OM&A, tax rates, and miscellaneous revenue as a result of changes to the 2004 Revenue Requirement.

COMPARISON OF AVERAGE RATE BASE
FOR THE BASE YEAR ENDED DECEMBER 31, 2002
ACTUAL YEAR ENDED DECEMBER 31, 2003
AND TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	BASE YEAR 2002	ADJ.	ACTUAL 2003	ADJ.	TEST YEAR 2004
	(a)	(b)	(c)	(d)	(e)	(f)
	Utility Investment					
1	Gross Plant	12,425,579	(46,828)	12,378,751 I	10,582	12,389,333 I
2	Accumulated Depreciation	(3,665,089)	(286,976)	(3,952,065) I	(356,557)	(4,308,622) I
3	Net Plant	8,760,490	(333,804)	8,426,686 I	(345,975)	8,080,711 I
4	Contributions in Aid of Construction	(19,880)	(3,340)	(23,220) I	(68)	(23,288) I
5	Total Plant	8,740,610	(337,144)	8,403,466 I	(346,043)	8,057,423 I
	Working Capital					
6	Cash	19,771	3,444	23,215 I	(2,245)	20,970 I
7	Goods & Services Tax, Net	(4,820)	(765)	(5,585) I	1,054	(4,531) I
8	Materials and Supplies	35,273	(5,140)	30,133 I	(1,201)	28,932 I
9	Transmission Linepack	42,834	0	42,834	0	42,834
10	Storage Gas	22,232	(6,038)	16,194	(577)	15,617
11	Prepayments and Deposits	1,601	375	1,976 I	100	2,076 I
12	Total Working Capital	116,891	(8,124)	108,767 I	(2,869)	105,898 I
	Deferred Costs					
13	Miscellaneous Deferred Items	51,457	(6,072)	45,385	(16,910)	28,475
14	Operating and Debt Service Deferrals	(48,252)	19,116	(29,136)	(1,303)	(30,439) I
15	Surplus Pension/Post Employment Benefits	12,332	14,899	27,231 I	14,094	41,325 I
16	Total Deferred Costs	15,537	27,943	43,480 I	(4,119)	39,361 I
17	Total Rate Base	8,873,038	(317,325)	8,555,713 I	(353,031)	8,202,682 I

I Updated to reflect 2003 actual balances.
I Updated to reflect impact of 2003 actuals on 2004 opening balances, adjustments to 2004 OM&A, pension funding, and associated working capital adjustments.

COMPARISON OF OVERALL RATE OF RETURN
AND TOTAL AVERAGE CAPITALIZATION FOR THE
BASE YEAR ENDED DECEMBER 31, 2002
ACTUAL YEAR ENDED DECEMBER 31, 2003, AND
TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	AMOUNT ($000)	RATIO %	COST RATE %	COST COMPONENT %	
	(a)	(b)	(c)	(d)	(e)	
	BASE YEAR ENDED DECEMBER 31, 2002					
1	Debt - Funded	5,078,522	57.18	9.17	5.24	
2	- Prefunded	(43,209)	(0.49)	9.14	(0.04)	
3	- Unfunded	4,924	0.05	2.73	0.00	
		5,040,237	56.74		5.20	
4	Junior Subordinated Debentures	911,764	10.26	8.96	0.92	
5	Common Equity	2,931,583	33.00	9.53	3.14	
6	Total Capitalization	8,883,584	100.00		9.26	
7	Rate Base	8,873,038				
8	GPUC	10,546				
9	Total Capitalization	8,883,584				
	ACTUAL YEAR ENDED DECEMBER 31, 2003					
10	Debt - Funded	4,900,060	57.21	9.09	5.20	I
11	- Prefunded	(32,219)	(0.38)	9.01	(0.03)	I
12	- Unfunded	59,679	0.70	3.11	0.02	I
13		4,927,520	57.53		5.19	I
14	Junior Subordinated Debentures	811,111	9.47	8.54	0.81	
15	Common Equity	2,826,490	33.00	9.79	3.23	I
16	Total Capitalization	8,565,121	100.00		9.23	I
17	Rate Base	8,555,713				I
18	GPUC	9,408				I
19	Total Capitalization	8,565,121				I
	TEST YEAR ENDING DECEMBER 31, 2004					
20	Debt - Funded	4,647,729	56.63	8.85	5.01	I
21	- Prefunded	(277,418)	(3.38)	8.73	(0.30)	I
22	- Unfunded	180,079	2.19	3.35	0.07	I
23		4,550,390	55.45		4.78	I
24	Junior Subordinated Debentures	373,521	4.55	7.27	0.33	
25	Common Equity	3,282,608	40.00	11.00	4.40	I
26	Total Capitalization	8,206,519	100.00		9.51	I
27	Rate Base	8,202,682				I
28	GPUC	3,837				I
29	Total Capitalization	8,206,519				I

I Updated to reflect actual 2003 amounts and the resulting changes to capitalization for 2004.

COMPARISON OF OPERATIONS, MAINTENANCE AND ADMINISTRATIVE
FOR THE BASE YEAR ENDED DECEMBER 31, 2002
THE ACTUAL YEAR ENDED DECEMBER 31, 2003
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	BASE YEAR 2002		ADJ.	ACTUAL 2003	ADJ.	TEST YEAR 2004	
	(a)	(b)		(c)	(d)	(e)	(f)	
1	OM&A Excluding Severance Program Amortization and Benefit	197,337	(1)	16,174	213,511	(1,164)	212,347	I
	Severance Program - 2001 and 2002 Service and Pricing Settlement							
2	Severance Program Amortization	8,637		(316)	8,321	(6,808)	1,513	I
3	Total Before Severance Program Benefits	205,974		15,858	221,832	(7,972)	213,860	I
4	Severance Program Benefits in 2003 and 2004 (2)	-		8,964	8,964	(6,767)	2,197	I
5	Less: Shipper Share of Severance Program Benefits in 2003 and 2004 (2)	-		(2,689)	(2,689)	2,030	(659)	I
6	Net TransCanada Benefits	-		6,275	6,275	(4,737)	1,538	I
7	Total OM&A	205,974		22,133	228,107	(12,709)	215,398	I

(1) Base Year OM&A excludes $3,858 of Regulatory Proceeding Costs now shown as a separate line item in the Revenue Requirement.

(2) Under the Mainline Services and Pricing Settlement, OM&A for 2002 was fixed and deemed to include severance benefits.
Consequently, for 2002 the shipper share of benefits was recorded in an Incentive Based Deferral Account rather than OM&A.

I Updated to reflect actual 2003 amounts, and updates to 2004 to reflect actuarial adjustments to pension expense, revised estimates for long-term incentive compensation, and adjustments to cost allocations.

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CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS	DEMAND TOLL ($/GJ/mo)	COMMODITY TOLL ($/GJ)	100% LF TOLL (¢/GJ)
	(a)	(b)	(c)	(d)
	CANADIAN FIRM TRANSPORTATION			
1	Saskatchewan Zone	7.40533	0.00949	25.295
2	Herbert to Saskatchewan Zone	5.27230	0.00601	17.935
3	Manitoba Zone	11.07444	0.01605	38.014
4	Welwyn to Manitoba Zone	4.30560	0.00501	14.656
5	Western Zone	17.87442	0.02683	61.448
6	Northern Zone	27.11887	0.04233	93.391
7	Eastern Zone	35.15844	0.05552	121.141
8	Bayhurst to Eastern Zone	34.82247	0.05497	119.982
9	Herbert to Eastern Zone	33.02540	0.05204	113.781
10	Southwest Zone	29.86773	0.04700	102.895
	EXPORT FIRM TRANSPORTATION			
11	Empress to Emerson	12.43842	0.01847	42.740
12	Empress to St. Clair	29.77365	0.04675	102.561
13	Empress to Chippawa	34.81313	0.05497	119.951
14	Empress to Niagara Falls	34.78668	0.05493	119.860
15	Empress to Iroquois	34.53970	0.05452	119.007
16	Empress to Cornwall	35.53944	0.05615	122.457
17	Empress to Napierville	37.27506	0.05898	128.446
18	Empress to Philipsburg	37.46831	0.05930	129.113
19	Steelman to Philipsburg	33.21892	0.05237	114.450
20	Empress to East Hereford	39.51536	0.06264	136.178
	MISC POINT-TO-POINT FIRM TRANSPORTATION			
21	Dawn to Enbridge CDA	4.47593	0.00543	15.258
22	Dawn to Enbridge EDA	8.79297	0.01257	30.165
23	Dawn to Union CDA	3.68603	0.00411	12.529
24	Dawn to Union EDA	7.20077	0.00995	24.669
25	Dawn to GMi - EDA	10.45499	0.01553	35.926
26	Dawn to Niagara Falls	4.43996	0.00543	15.140
27	Dawn to Iroquois	8.34563	0.01180	28.618
28	St. Clair to Union SWDA	1.19858	0.00009	3.950
29	St. Clair to Chippawa	4.73004	0.00590	16.141
30	Kirkwall to Chippawa	2.37828	0.00206	8.025
31	St. Clair to East Hereford	13.02047	0.01942	44.749

* All tolls are expressed and payable in Canadian Dollars.

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PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS	DEMAND TOLL ($/GJ/mo)	COMMODITY TOLL ($/GJ)
	(a)	(b)	(c)
	STORAGE TRANSPORTATION SERVICE		
1	Centra Gas (Manitoba) - MDA	2.78917	0.00273
2	Union Gas - WDA	17.98333	0.02752
3	Union Gas - NDA	7.25167	0.01001
4	Union Gas - EDA	4.63500	0.00575
5	Kingston	4.47500	0.00548
6	Gaz Métropolitain - EDA	8.12500	0.01144
7	Enbridge Gas - CDA	1.13667	0.00004
8	Enbridge Gas - EDA	2.98583	0.00306
9	Cornwall	6.27000	0.00841
10	Philipsburg	8.19833	0.01156
	LONG TERM WINTER FIRM SERVICE		
11	Empress to Iroquois		1.66610

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PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS (a)	MINIMUM (1) ($/GJ) (b)
	SHORT TERM FIRM TRANSPORTATION	
1	Empress to Saskatchewan Zone	0.25295
2	Herbert to Saskatchewan Zone	0.17935
3	Empress to Manitoba Zone	0.38014
4	Welwyn to Manitoba Zone	0.14656
5	Empress to Western Zone	0.61448
6	Empress to Northern Zone	0.93391
7	Bayhurst to Eastern Zone	1.19982
8	Herbert to Eastern Zone	1.13781
9	Empress to Eastern Zone	1.21141
10	Empress to Southwest Zone	1.02895
11	Empress to Emerson	0.42740
12	Empress to St. Clair	1.02561
13	Empress to Chippawa	1.19951
14	Empress to Niagara Falls	1.19860
15	Empress to Iroquois	1.19007
16	Empress to Cornwall	1.22457
17	Empress to Napierville	1.28446
18	Empress to Philipsburg	1.29113
19	Steelman to Philipsburg	1.14450
20	Empress to East Hereford	1.36178
21	Dawn to Enbridge CDA	0.15258
22	Dawn to Enbridge EDA	0.30165
23	Dawn to Union CDA	0.12529
24	Dawn to Union EDA	0.24669
25	Dawn to GMi - EDA	0.35926
26	Dawn to Niagara Falls	0.15140
27	Dawn to Iroquois	0.28618
28	St. Clair to Union SWDA	0.03950
29	St. Clair to Chippawa	0.16141
30	Kirkwall to Chippawa	0.08025
31	St. Clair to East Hereford	0.44749

(1) The Minimum STFT Toll is the 100% Load Factor FT toll for the applicable path.

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PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS (a)	COMMODITY TOLL ($/GJ) (b)
	BACKHAUL SERVICE	
	Chippawa to Union SWDA	
1	Winter IT	0.15374
2	Summer IT	0.07687
	Emerson to Centra MDA	
3	Winter IT	0.09169
4	Summer IT	0.04585
	Dawn to St. Clair	
5	Winter IT	0.04525
6	Summer IT	0.02262
	Emerson to Empress	
7	Winter IT	0.40893
8	Summer IT	0.20447
	MULTIPLE HANDSHAKES (MHPS) *(1)	
9	Winter Minimum	0.00000
10	Winter Maximum	0.00000
11	Summer Minimum	0.00000
12	Summer Maximum	0.00000
	ENHANCED CAPACITY RELEASE	
13	ECR Surcharge	0.03657

LINE NO.	DELIVERY PRESSURE (a)	DEMAND TOLL ($/GJ/mo) (b)	COMMODITY TOLL ($/GJ) (c)	DAILY EQUIVALENT *(2) ($/GJ) (d)
14	Emerson - 1 (Viking)	0.12613	0.00000	0.00415
15	Emerson - 2 (Great Lakes)	0.15676	0.00000	0.00515
16	Dawn	0.10089	0.00000	0.00332
17	Niagara Falls	0.10818	0.00000	0.00356
18	Iroquois	0.82586	0.00000	0.02715
19	Chippawa	1.12392	0.00000	0.03695
20	East Hereford	1.60608	0.01072	0.06352

*(1) As per TTF Resolution 07.2003, Mulitple Handshakes and Pooling Service has been terminated.
The resolution incorporates "no cost" title transfer as a feature of transportation services.

*(2) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, and STFT.

2004 Mainline Tolls and Tariff Application
February 2004 Update

APPENDIX C:
FUEL GAS AND INCENTIVE PROGRAM

1.0 FUEL GAS INCENTIVE PROGRAM

Q1. What is the purpose of this evidence?

A1. The purpose of this evidence is to seek approval for a Fuel Gas Incentive Program for 2004 by providing rationale and details of the proposed program.

Q2. Please describe the contents of this evidence.

A2. The contents of this evidence are as follows:

- Appendix C — Written Evidence Respecting the 2004 Fuel Gas Incentive Program
- Attachment 1 — Summary of Fuel Gas Incentive Program Results
- Attachment 2 — Proposed 2004 Incentive Payment Calculation
- Attachment 3 — Graphs illustrating target equations and actual averages

Q3. Has TransCanada previously implemented a Fuel Incentive Program?

A3. Yes. As part of the Mainline 2001 and 2002 Service and Pricing Settlement, TransCanada negotiated a Fuel Gas Incentive Program with its stakeholders. The term of the program was from November 1, 2001 to December 31, 2002 and applied to the Prairies and Northern Ontario sections of the Mainline system. For 2003, TransCanada applied for, and received NEB approval to implement a Fuel Gas Incentive Program which used the same target equations and incentive schedule that was negotiated as part of the Settlement.

Q4. Why does TransCanada consider it appropriate to continue a Fuel Incentive Program?

A4. In the RH-1-2002 proceeding respecting 2003 tolls, TransCanada proposed the fuel incentive program, describing at length both the mechanics of the program and the merits of the program that accrue to shippers and TransCanada.

In its RH-1-2002 Decision, the Board found that the Fuel Incentive Program provided an appropriate balance between benefits to shippers and TransCanada. Further, the Board stated that a fuel program is particularly important for the Mainline, due to the fact that the Mainline fuel ratio is generally higher than that of other pipelines and that the fuel costs were expected to account for approximately $500 million in 2003. The Board concluded that the benefits of the program, in terms of fuel savings, outweighed its cost in terms of incentive payments payable to TransCanada.

In TransCanada's view, the merits of the program and the findings discussed by the Board in the RH-1-2002 Decision remain relevant and appropriate factors which support continuing the Fuel Incentive Program in 2004.

Q5. Has TransCanada communicated the results of the 2001/02 Fuel Gas Incentive Program to its stakeholders?

A5. Yes. The results were shared at the July 10, 2003 TTF meeting. The results included a summary of the program details, fuel volume savings achieved, and a summary of how the savings were achieved. This evidence further reports results to all Mainline shippers and the Board.

Q6. Please provide the results of 2001/02 Fuel Gas Incentive Program.

A6. For the 2001/2002 Fuel Gas Incentive Program, the fuel volume savings relative to target averaged approximately 287 10^3m^3/d over the 14 month period. TransCanada estimates the annual fuel savings derived from the program to be $18.2 million. Shippers realized a benefit of approximately $11.5 million and TransCanada's incentive payment amounted to approximately $6.7 million. Details of the program results are provided in Attachment 1which includes a summary of the seasonal results in accordance with the reporting requirements of the Settlement, monthly flow and fuel data, and monthly electric utilization data used in the determination of the electric adjustment.

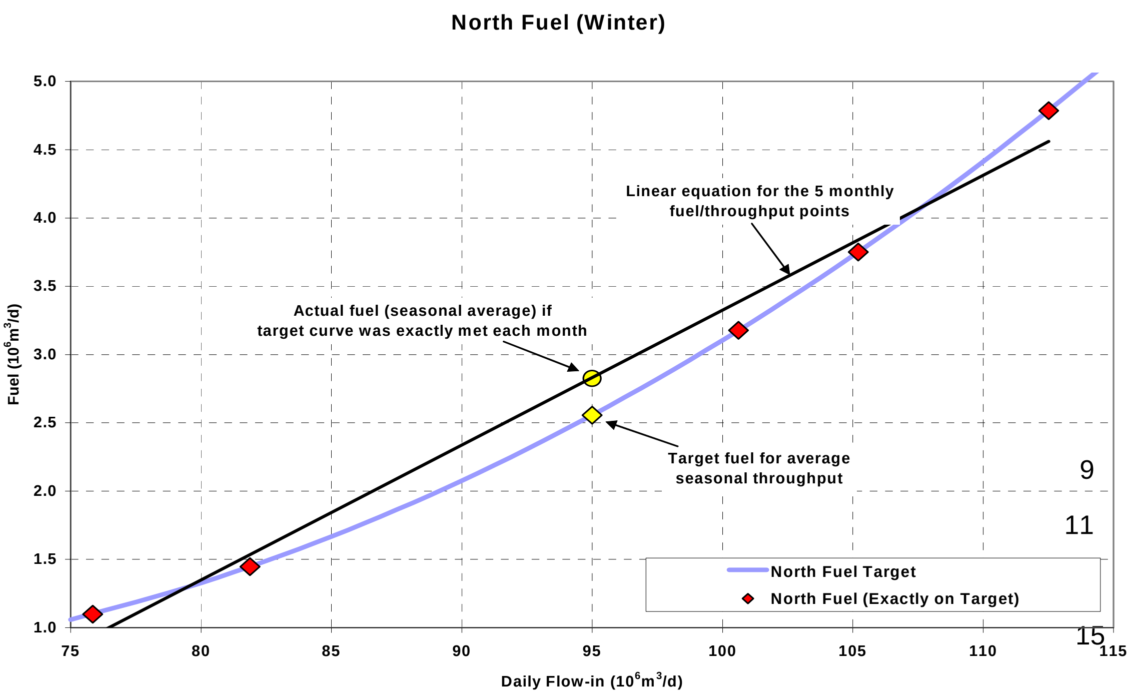
Q7. What are the results of the 2003 Fuel Gas Incentive Program?

A7. The results of the 2003 Fuel Gas Incentive Program are provided in Attachment 1. In accordance with the incentive payment schedule, the incentive payment to TransCanada amounted to $4.412 million for the seasonal fuel savings of 351 10^3m^3/d achieved for the summer (April to October) operation. There was no incentive payment for the seasonal average of 8 10^3m^3/d of fuel savings saved during the 2003 winter period (January-March and November-December).

The 2003 winter operation resulted in no incentive payment primarily due to the large range of flows experienced over the split season (January-March and November-December).

Q8. Please provide further explanation of the winter 2003 results.

A8. While targets are expressed as fuel curves which are non-linear, a linear average is used to calculate seasonal flow and fuel. This affects reward calculation results as illustrated in the graph below. In this theoretical example, even when the actual performance was at the target level each month, the average actual fuel performance would be calculated above the target curve.



The incentive payment calculation has, for 2001/02 and 2003, employed seasonal averaging to calculate fuel and flow for simplicity. The inherent inaccuracy of this linear averaging relative to the non-linear target equations was recognized and accepted as a risk by TransCanada. An alternative approach would be to calculate the fuel savings relative to target on a monthly basis, and then average these monthly fuel savings for the season. The following table illustrates the difference between the current seasonal averaging and the alternative approach of averaging the actual monthly savings.

	Seasonal Fuel Savings ($10^3m^3/d$)	Average of Monthly Fuel Savings ($10^3m^3/d$)
Winter 01/02	208	255
Summer 02	338	345
Winter 02	305	357
Summer 03	351	381
Winter 03	8	431

For the 2003 winter period, the table shows that significant fuel savings were achieved on a monthly basis, but the wide range of flows and seasonal averaging resulted in low calculated seasonal fuel savings. Up to the winter of 2003, this seasonal averaging effect was not large. However, the relatively extreme flow fluctuation in the past winter season yielded low seasonal average fuel savings results.

Q9. Is TransCanada proposing any change to the 2004 program to calculate fuel savings on the basis of average monthly rather than seasonal fuel savings or to otherwise reflect the experience of the winter 2003 season?

A9. No, not for the 2004 program. If approved, TransCanada will continue to monitor and evaluate all aspects of the program in 2004 and may propose modifications based on that evaluation in event it seeks continuation of the program beyond 2004.

Q10. Describe how TransCanada achieved the past fuel incentive benefits.

A10. TransCanada was able to reduce fuel usage through:

- improved linepack management
- a compressor wheel change at Station 75
- improved outage coordination together with the appropriate balancing of O&M expenditures
- enhanced internal processes for developing operating strategies, responding to daily changes and monitoring system performance.

Since the Fuel Incentive Programs were implemented in November 2001, TransCanada has been able to operate at slightly higher linepack levels. The target equations assumed an operation at 96% of maximum theoretical linepack, consistent with actual operations prior to the fuel incentive programs. Since November 2001, linepack levels have averaged approximately 96.7% of maximum theoretical linepack. The improvements in operational linepack levels together with the one wheel change at Station 75 are estimated to have contributed to approximately one-third of the total fuel savings achieved relative to target. The balance of the benefits realized under the program are primarily due to improved outage coordination, the appropriate balancing of O&M when managing outages, and the enhanced internal processes referred to above.

Q11. Please describe TransCanada's proposed Fuel Gas Incentive Program for 2004.

A11. TransCanada is proposing the continuation of a fuel incentive program in which TransCanada would be compensated for achieving fuel savings relative to specified target levels. Many aspects of the proposed program are similar to the 2001/02 and 2003 Fuel Gas Incentive Programs.

Under the proposed 2004 program, fuel savings would be determined by comparing the net actual fuel consumption for each season with the target fuel, and an incentive amount would then be determined based on that fuel volume saved (i.e. the incentive amount is not tied to the price of gas). Incentive amounts would be determined for winter and summer seasons separately, recorded in a deferral account and included in the 2005 revenue requirement.

The proposed fuel targets are equations that relate fuel consumption to flow on both the Prairies and Northern Ontario sections for both the winter and summer seasons. Equations are used, rather than a single fuel consumption figure, to allow for changes in fuel consumption that occur as throughput changes. Therefore, the actual flow into both the Prairies and Northern Ontario sections would be used in the equation to determine the respective fuel targets.

The targets would also be adjusted for actual electric unit utilization to account for differences from the utilization assumed in the target equations. With the current flexibility on the system, TransCanada can choose whether it runs the electric or gas-driven units. TransCanada makes these decisions on an economic basis considering current gas prices and the pricing reflected in the power supply contracts for the electric units. Without an adjustment, TransCanada would be incented to maximize the use of the electric units in order to minimize fuel. Maximum use of the electric units is not always the most economic operation and therefore, would not always result in the lowest delivered cost for shippers. Therefore, an adjustment for electric utilization is appropriate. The total fuel target for each season would then be the sum of the targets for Prairies and Northern Ontario sections plus the electric utilization adjustment.

Actual fuel consumption is determined from TransCanada's actual fuel gas use from Station 2 to 116.

Q12. What changes are being proposed for the 2004 program?

A12. The changes from the 2001/02 and 2003 Fuel Gas Incentive Programs are:

- fuel volume savings are calculated using the actual fuel volume net of adjustments;
- target equations reflect physical system changes since the Fuel Incentive Programs commenced in November 2001;
- target equations are effectively re-based to the 2001/02 and 2002/2003 operating conditions; and
- the incentive schedule is revised to reflect past performance, and the level of effort required to sustain and improve on that performance.

1.1 Net Actual Fuel

Q13. Describe the change to the fuel volume saving calculation in the 2004 Fuel Gas Incentive Program.

A13. TransCanada is proposing to calculate the annual fuel incentive amount on the basis of actual fuel volume net of adjustments as opposed to actual fuel.

Q14. Why is TransCanada proposing this change?

A14. In order to ensure the original intent behind the fuel incentive is maintained, TransCanada requires the current incentive calculation methodology to be adjusted. The actual fuel volume will be adjusted by the level of fuel compensation provided to the Mainline shippers as a result of an arrangement between TransCanada Pipelines Limited and TransCanada Power LP ("TCP LP") regarding cogeneration facilities in Northern Ontario.

Q15. Describe the details behind TransCanada entering this arrangement.

A15. TransCanada and TCP LP entered into an agreement, effective October 6th, 2003, that may result in TransCanada changing the way it operates its system. Given the forecast for lower Mainline flows, the most efficient mode of operation may, in the absence of the arrangement, result in TransCanada not operating the compressors to which the cogeneration facilities are attached. To ensure these facilities operate as much as possible, TCP LP has agreed to compensate the Mainline and Mainline shippers for any incremental costs and fuel associated with running the specific compressors.

Q16. What compressors and facilities are related to this arrangement?

A16. TCP LP owns and operates electrical power generation facilities located adjacent to the following TransCanada compressors stations in the Northern Ontario section ("cogeneration locations"):

- Station 75 Nipigon
- Station 88 Calstock
- Station 95 Kapuskasing
- Station 102 Potter
- Station 116 North Bay

Q17. Please describe the details of the arrangement.

A17. Under the terms of the arrangement, TransCanada agrees that it will make reasonable efforts to maximize the operation of compressors at the cogeneration locations. In order to keep the TransCanada Mainline and its shippers whole, TCP LP agrees that it will pay any incremental fuel consumed and ancillary costs incurred as a result of the priority operation of these compressor stations.

Q18. How will incremental fuel gas be determined and how will TCP LP provide compensation for incremental fuel gas?

A18. TransCanada will determine incremental fuel amounts using pipeline simulations. These simulations will analyze, on a daily basis, the difference in fuel consumption between the operation with compression running at the cogeneration locations and the optimized pipeline operation. These incremental fuel amounts will be provided as fuel-in-kind by TCP LP at Empress, and will be used to compensate the Mainline shippers for the incremental amount of fuel collected through the fuel ratio.

Q19. Are there other costs incurred as a result of this arrangement?

A19. Yes. Costs associated with incremental OM&A expenses and fuel taxes will be paid by TCP LP.

Q20. How does this arrangement with TCP LP affect the 2003 fuel incentive program?

A20. TransCanada has not proposed any changes to the 2003 fuel incentive program as a result of the arrangement with TCP LP. For 2003, the incentive mechanism will continue to be based upon the actual fuel consumed relative to the target levels. Given that TransCanada's fuel consumption may be higher than optimal as a result of changes to the operation to ensure that the compressors at cogeneration locations are running, shippers will be compensated by TCP LP for any such increase through a reduction in their fuel ratio.

While shippers will be compensated for the incremental fuel consumed, TransCanada's eligibility for that portion of the fuel incentive will be lost as the fuel incentive is based upon actual fuel consumed. As such, there will be no adverse effect to the Mainline shippers on the 2003 Fuel Incentive Program.

1.2 Target Equations

Q21. Describe how TransCanada determined the target equations and electric utilization adjustments.

A21. TransCanada initially developed theoretical fuel curves / equations for the Prairies and Northern Ontario sections based on pipeline simulation results for a wide range of flows. These represent the least fuel consumption that can theoretically be achieved, but cannot be maintained on a sustained basis. They assume optimum linepack levels, design compressor efficiencies and no equipment outages. The impacts of historical outages and linepack levels, as well as expected operating compressor efficiencies under each flow condition were then simulated to achieve a fuel versus flow relationship that represents actual operations since the fuel incentive program was implemented (i.e. for the 2001/02 and 2002/03 contract years). Once differences between actual electric utilization and those assumed in the target equations are accounted for, the simulated target curves align closely with the actual operating data for 2001/02 and 2002/03. Graphs illustrating the target curves are provided in Attachment 3. They include the target curves used in the 2003 Fuel Incentive program, the proposed target curves and actual seasonal operating data during the past incentive programs.

The electric utilization adjustments are based on the efficiency of the alternate gas-driven compression at all of the electric units sites. For example, the electric unit at Station 52 (C Plant) would be replaced by Plants A and B at Station 52. The other electric unit sites that are covered by the proposed fuel incentive are Stations 9 (E Plant), 17 (E Plant) and 41 (F & G Plants). For both the winter and summer, the adjustment factor is based on a change in fuel consumption of 1.3 $10^6 m^3/d$ for a change in electric utilization of 3,600 MW-hrs/day. The winter adjustment reflects that the winter target equations assume an average of 3,120 MW-hrs/day for the electric units. The summer adjustment reflects an average of 2,650 MW-hrs/day in the summer target equations.

Q22. Describe any changes to the physical system from that assumed in the approved 2003 target equations to the proposed target equations.

A22. The proposed 2004 target equations reflect the retirement of reciprocating units at Stations 25 and 68 as well as a compressor wheel change at Station 75 B Plant. These system changes were not reflected in the approved 2003 target equations.

Q23. Provide the rationale for why the proposed target equations are reasonable.

A23. The proposed target equations were developed using the same methodology as the original 2001/02 and approved 2003 equations. The proposed target equations were developed to reflect the actual operations from the commencement of the fuel incentive programs in November 2001 up to and including July 2003. The proposed equations reflect the changes to the physical system that have occurred over that period as well as the benefits realized through improved linepack management, improved outage management, and improved system optimization over the past two years. Therefore, TransCanada's proposal means that it must achieve and improve on its performance under the past fuel incentives to earn an incentive payment under the proposed program. The new equations are thus effectively re-based to the 2001/02 and 2002/03 operating conditions.

Q24. What is the practical effect of rebasing the target equations?

A24. TransCanada expects that it will be much more difficult to meet and exceed the rebased targets in the future. The Company expects that in order to achieve further meaningful levels of efficiency gains, significant focus, innovation and long-term technology initiatives will be required.

As a consequence of the rebasing and TransCanada's expectation that further significant efficiency gains will likely only be realizable over the longer term, TransCanada expects that it will seek to have the fuel incentive program extended in years beyond 2004 in order to capture the benefit of longer term initiatives.

Q25. Why are target equations for that part of the system downstream of Station 116 not included?

A25. Target equations were not developed for that part of the Mainline downstream of Station 116. The different routing options that are possible with changing market conditions make it more difficult to develop target equations that relate fuel and flow for this section of the Mainline. Since approximately 85% of the Mainline fuel is consumed in the Prairies and Northern Ontario sections, the sections downstream of Station 116 are not included in the fuel incentive proposal.

1.3 Incentive Schedule

Q26. Please describe how the proposed 2004 incentive schedule was derived.

A26. The proposed incentive schedule is based on the previously approved incentive schedule for 2003, adjusted to reflect those changes that are physically sustainable. TransCanada estimates that improvements in operational linepack levels together with a wheel change at Station 75 have contributed about one-third of the approximately 300 10^3m^3/d total fuel savings achieved relative to the 2001/02 and 2003 targets. This portion of achieved fuel savings is considered sustainable with little additional cost. The balance of the benefits require operational decisions which align with the objective of overall system efficiency as opposed to operating cost savings, and the incentive mechanism is designed to elicit the appropriate balanced decisions. TransCanada views these benefits as discretionary and therefore eligible to earn a corresponding incentive, both to maintain them and to improve upon current performance levels.

Q27. How does the proposed incentive schedule relate to that approved for 2003?

A27. Approximately two-thirds, or 200 10^3m^3/d, of the average 300 10^3m^3/d of fuel savings achieved in the program to date should continue to be subject to incentive. Therefore, no incentive payment would be earned for efficiency performance at less than that level. TransCanada proposes an incentive payment of $3.5 Million for maintaining the most recently achieved level of efficiency as represented by the proposed 2004 targets. The net benefit to Mainline shippers at the base level is estimated at $19.6 Million (assuming a gas price of $5.62/GJ at Empress for 2004). The remainder of the incentive schedule follows the same increments of incentive amount for increments of fuel savings as the 2003 approved schedule as shown in the following table.

2004 Proposed Schedule		2003 Approved Schedule	
Fuel Volume Savings ($10^3m^3/d$)	**Annual Incentive Amount ($ million)**	**Fuel Volume Savings ($10^3m^3/d$)**	**Annual Incentive Amount ($ million)**
		0	0
		100	1.5
0	3.5	200	3.5
100	6.0	300	6.0
200	9.0	400	9.0
300	12.0	500	12.0
400	15.0	600	15.0

The Total Incentive Payment calculation will be based on a calculation completed at the end of each season, as described in Attachment 2. For fuel volume savings between any two of the defined increments, incentive amounts would be equal to the prorated dollar amounts between those two points.

Q28. Does this conclude TransCanada's written evidence on the proposed 2004 Fuel Incentive Program?

A28. Yes.

FUEL INCENTIVE PROGRAM ACTUAL RESULTS
FOR THE YEAR ENDED DECEMBER 31, 2003

FUEL GAS INCENTIVE
($000)

Line No.	Particulars	Summer Season Ended October 31, 2003 Amount ($10^6m^3/d$)	Winter Season Ended December 31, 2003 Amount ($10^6m^3/d$)	Total
	(a)	(b)	(c)	(d)
	Actual Flows			
1	Actual Prairies Line Flow-in	155.98	179.24	
2	Actual Northern Ontario Line Flow-in	82.50	95.00	
	Target Fuel			
3	Prairies Target Fuel	1.850	2.682	
4	Northern Ontario Target Fuel	1.916	2.555	
5	Average Daily Electric Unit Usage	2,647.0	2,725.9	
6	Electric Utilization Adjustment	0.001	0.142	
7	Partial Season Adjustment			
8	Seasonal Target Fuel (Lines 3, 4, 6 and 7)	3.767	5.379	
	Actual Fuel			
9	Actual Prairies Fuel Volume	1.636	2.545	
10	Actual Northern Ontario Fuel Volume	1.780	2.826	
11	Total Actual Fuel Volume (Lines 9 to 10)	3.416	5.371	
12	Fuel Volume Savings (Line 8 - Line 11)	0.351	0.008	
		Amount ($000)	Amount ($000)	Amount ($000)
13	Seasonal Incentive Amount	4,412	0	4,412

Note
(1) Reported figures are recorded in 106m3/d, except for #5 (Average Daily Electric Unit Usage), which is recorded in MW-hrs/day.

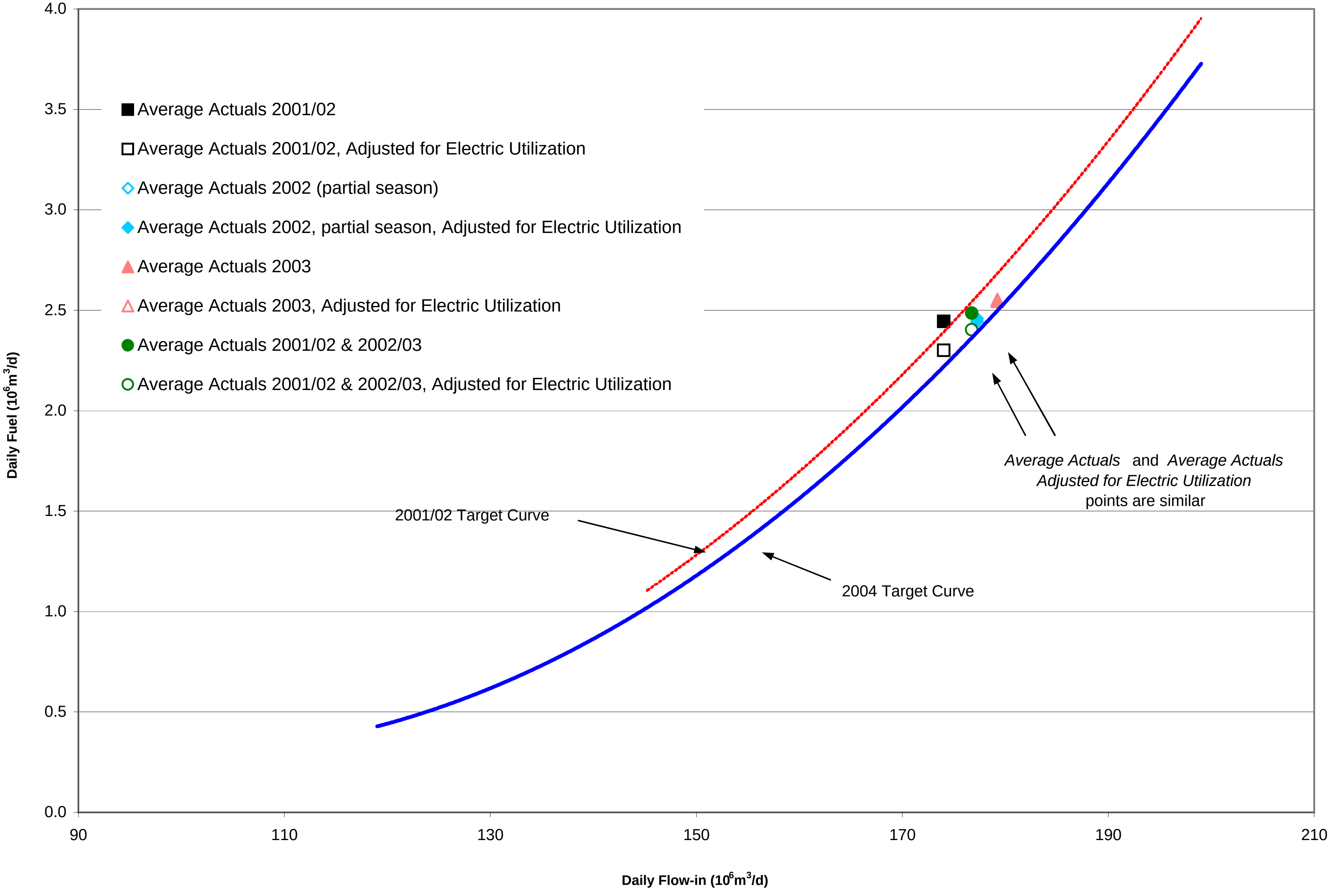
Updated to reflect actual results for 2003

Fuel Incentive - Actual Monthly Flow versus Fuel ($10^6 m^3/d$) and Electric Unit Usage (MW-hrs/day)

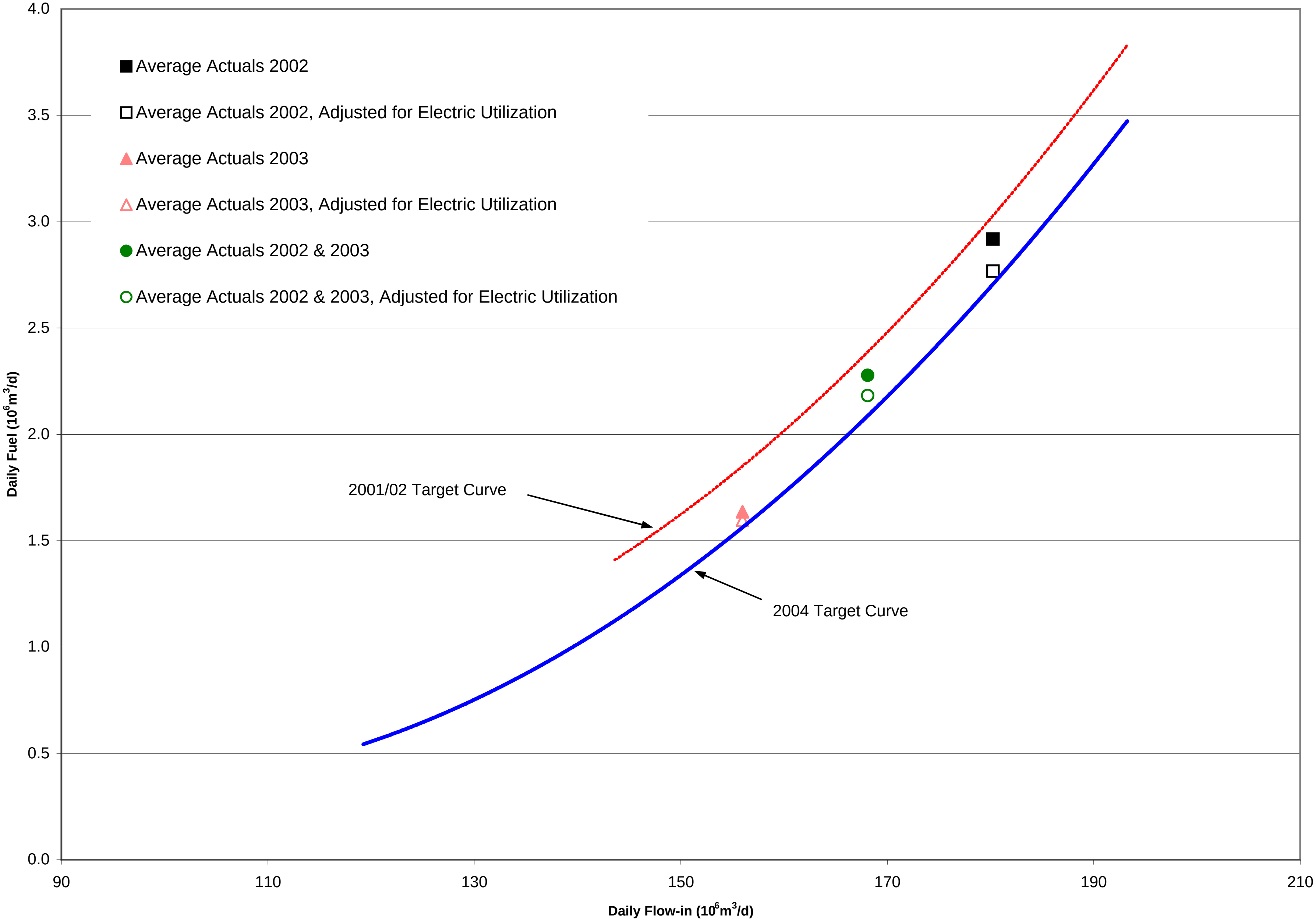
	Prairies Line		Northern Ontario Line		Electric Usage
	Flow	Fuel	Flow	Fuel	
Nov./01	164.0	1.964	91.8	2.496	2,524.7
Dec./01	160.8	1.759	94.0	2.429	2,394.3
Jan./02	178.4	2.722	96.8	2.812	1,881.6
Feb./02	186.8	3.080	100.5	3.160	1,948.7
Mar./02	181.1	2.741	98.4	3.039	1,913.2
Apr./02	177.0	2.625	99.8	3.172	2,019.8
May/02	177.5	2.737	100.5	3.278	2,315.8
Jun./02	178.2	2.838	98.3	3.389	2,325.7
Jul./02	184.1	3.265	102.9	4.380	2,157.4
Aug./02	182.6	3.111	101.5	4.210	1,974.2
Sep./02	180.8	3.027	98.5	3.792	1,948.0
Oct./02	181.4	2.814	95.5	2.991	2,390.3
Nov./02	172.1	2.294	90.2	2.248	2,903.6
Dec./02	182.2	2.589	94.2	2.496	2,928.6
Jan./03	192.7	3.006	105.2	3.468	3,125.5
Feb./03	205.7	3.777	112.5	4.529	3,166.2
Mar./03	189.0	2.922	100.6	3.170	3,009.8
Apr./03	160.7	1.628	86.7	1.800	2,907.9
May/03	158.5	1.521	84.2	1.687	2,812.8
Jun./03	164.7	1.963	90.8	2.583	2,730.1
Jul./03	156.2	1.738	81.2	1.773	2,676.4
Aug./03	154.9	1.749	79.4	1.747	2,267.5
Sep./03	146.0	1.432	75.0	1.362	2,269.9
Oct./03	150.9	1.426	80.5	1.521	2,863.6
Nov./03	144.7	1.195	75.8	1.398	2,438.0
Dec./03	165.5	1.900	81.9	1.686	1,923.2

Updated to reflect 2003 actual results

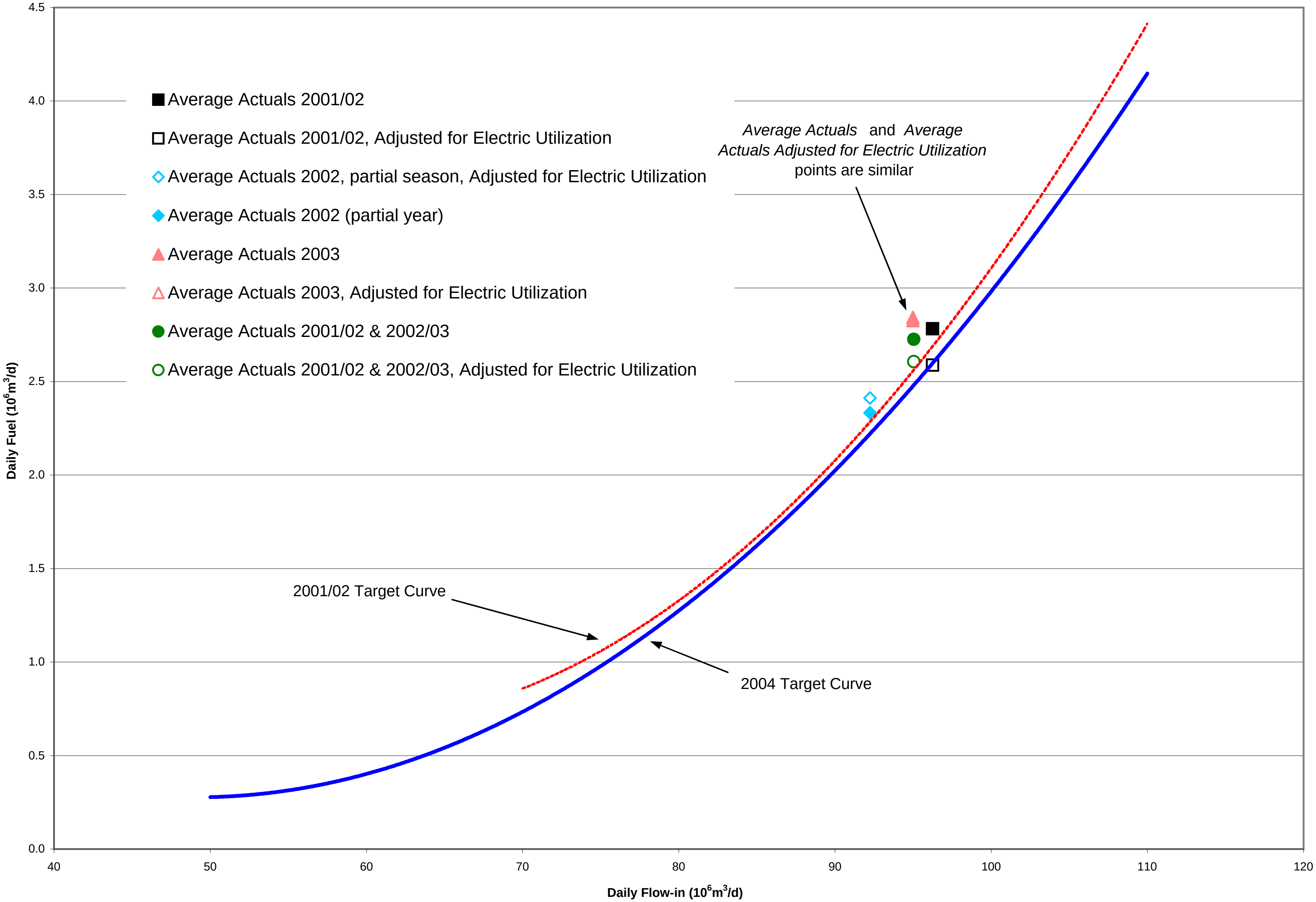
Prairies Section
Winter Target Fuel Curves and Average Actuals



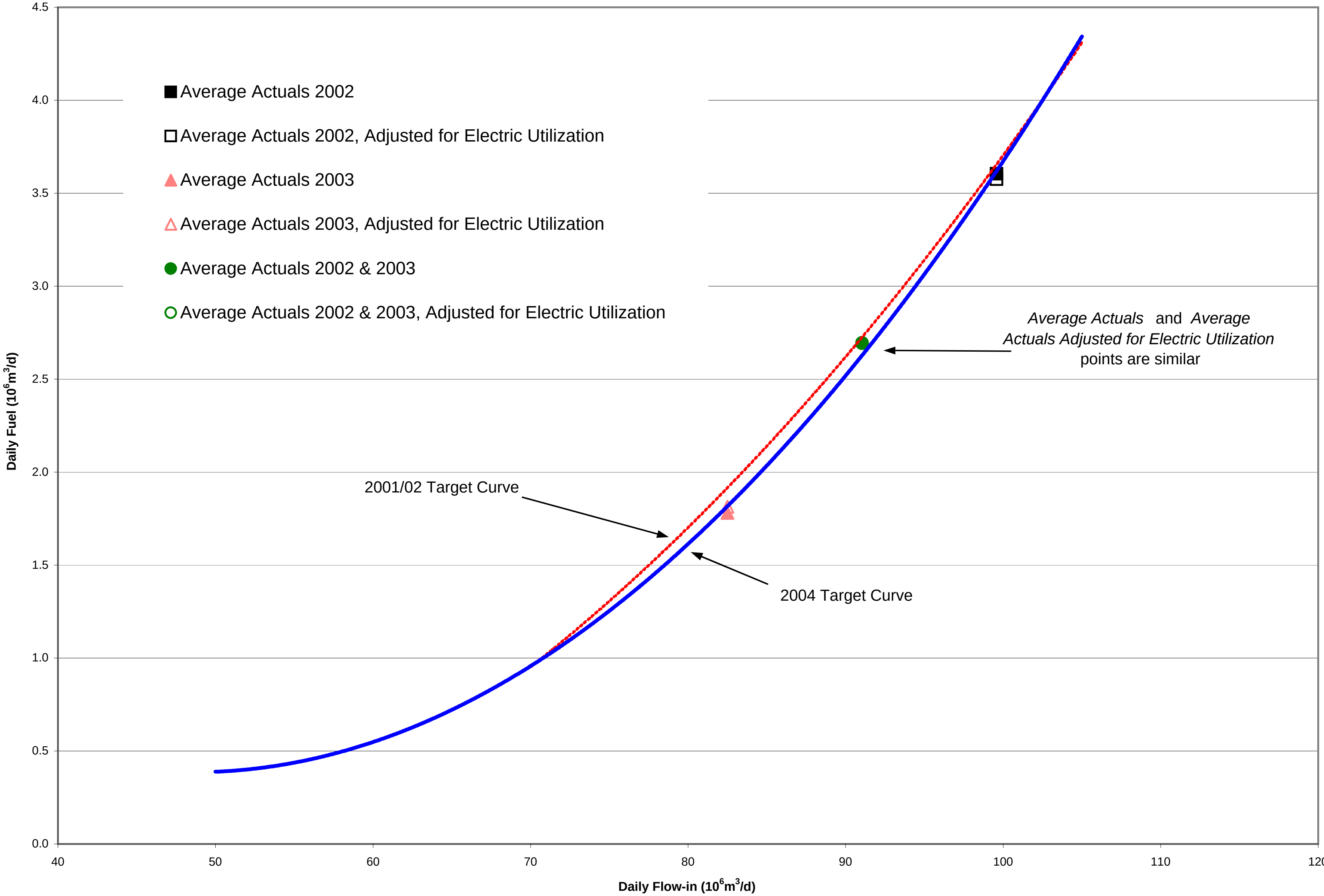
Prairies Section
Summer Target Fuel Curves and Average Actuals



Northern Ontario Section
Winter Target Fuel Curves and Average Actuals



Northern Ontario Section
Summer Target Fuel Curves and Average Actuals



Updated to reflect 2003 actual results

2004 Mainline Tolls and Tariff Application
February 2004 Update

APPENDIX D:
SERVICES – ATTACHMENT D-2

Revised February 2004

NON RENEWABLE FIRM TRANSPORTATION SERVICE CONTRACT

THIS NON RENEWABLE FIRM TRANSPORTATION SERVICE CONTRACT, made as of the ___ day of ____________, 200__.

BETWEEN:

TRANSCANADA PIPELINES LIMITED
a Canadian Corporation ("TransCanada")
OF THE FIRST PART

AND:

__________________________, a company incorporated under
the laws of _____________ ("Shipper")
OF THE SECOND PART

WITNESSES THAT:

WHEREAS TransCanada owns and operates a natural gas pipeline system extending from a point near the Alberta/Saskatchewan border where TransCanada's facilities interconnect with the facilities of NOVA Gas Transmission Ltd. easterly to the Province of Quebec with branch lines extending to various points on the Canada/United States of America International Border; and

WHEREAS Shipper has satisfied in full, or TransCanada has waived, each of the availability conditions set out in Section 1.1 of TransCanada's ~~FT-RN~~ **FT-NR** Toll Schedule referred to in Section 8.1 hereof; and

WHEREAS the quantities of gas delivered hereunder by Shipper or Shipper's agent to TransCanada are to be removed from the province or country of production of such gas by Shipper and/or Shipper's suppliers and/or its (their) designated agent(s) pursuant to valid and subsisting permits, licenses or other such authorizations.

NOW THEREFORE, IN CONSIDERATION OF THE PREMISES AND THE MUTUAL COVENANTS AND AGREEMENTS HEREIN CONTAINED, TRANSCANADA AND SHIPPER COVENANT AND AGREE AS FOLLOWS:

ARTICLE I - DEFINITIONS

1.1 Capitalized terms used but not defined in this Contract shall have the meaning ascribed to such terms in the ~~FT-RN~~ **FT-NR** Toll Schedule and in TransCanada's Transportation Tariff, as they may be amended from time to time.

ARTICLE II - GAS TO BE TRANSPORTED

2.1 Subject to the provisions of this Contract, the FT-NR Toll Schedule, the List of Tolls, and the General Terms and Conditions referred to in Section 8.1 hereof, TransCanada shall provide firm transportation service to Shipper for such period of time and in respect of a quantity of gas not in excess of the Maximum Daily Quantity specified in each Addendum to this Contract executed from time to time, which Addendum shall be in the forms attached hereto as Exhibit "A" ~~and Exhibit "B"~~.

ARTICLE III - DELIVERY POINT(S) AND RECEIPT POINT(S)

3.1 The Delivery Point(s) hereunder are those points specified as such in each Exhibit "A" ~~and/or Exhibit "B"~~ Addendum entered into from time to time by the parties.

3.2 The Receipt Point(s) hereunder are those points specified as such in each Exhibit "A" ~~and/or Exhibit "B"~~ Addendum entered into from time to time by the parties.

ARTICLE IV - TOLLS

4.1 Shipper shall pay for all transportation service hereunder in accordance with TransCanada's ~~FT-RN~~ **FT-NR** Toll Schedule, List of Tolls, and General Terms and Conditions set out in TransCanada's Transportation Tariff, as each may be amended from time to time by the National Energy Board ("NEB"). The toll to be paid by Shipper hereunder shall be that FT-NR Bid Price specified in each Exhibit "A" ~~and/or Exhibit "B"~~ Addendum to this Contract entered into from time to time by the parties for the transportation service described therein.

ARTICLE V - TERM OF CONTRACT

~~5.1 This contract shall be effective from the date hereof and shall continue in force unless terminated in accordance with Section 5.2 hereof or the provisions of the General Terms and Conditions set out in TransCanada's Transportation Tariff.~~

~~5.2 In addition to the termination provisions set out in the General Terms and Conditions of TransCanada's Transportation Tariff, either party shall have the right to terminate this Contract at any time by giving the other party thirty (30) days prior written notice. Upon expiration of the aforesaid thirty (30) day period, this Contract shall terminate and be of no further force or effect; provided that nothing herein shall relieve either party from any obligations which arose prior to the effective date of such termination, including all obligations under each Exhibit "A" and Exhibit "B" Addendums in force on the effective date of such termination.~~

5.1 This Contract shall be effective from the date hereof and shall continue until the _____day of _____________, ______.

ARTICLE VI - NOTICES

6.1 Any notice, request, demand, statement or bill (for the purpose of this paragraph, collectively referred to as "Notice") to or upon the respective parties hereto shall be in writing and shall be directed as follows:

IN THE CASE OF TRANSCANADA: TransCanada PipeLines Limited

(i) mailing address:	P.O. Box 1000 Station M Calgary, Alberta T2P 4K5	
(ii) delivery address:	TransCanada Tower 450 – 1st Street S.W. Calgary, Alberta, T2P 5H1	
	Attention: Telecopy:	Director, Customer Service (403) 920-2446
(iii) nominations:	Attention: Telecopy:	Manager, Nominations & Allocations (403) 920-7473
(iv) bills:	Attention: Telecopy:	Manager, Contracts & Billing (403) 920-2384
(v) other matters:	Attention: Telecopy:	Director,Customer Service (403) 920-2446

IN THE CASE OF SHIPPER:

(i) mailing address:	____________	
	____________	
	____________	
(ii) delivery address:	____________	
	____________	
(iii) nominations:	Attention:	____________
	Telecopy:	____________
(iv) bills:	Attention:	____________
	Telecopy:	____________
	E-mail address:	____________
(v) other matters:	Attention:	____________
	Telecopy:	____________

Notice may be given by telecopier or other telecommunication device and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event regular mail service, courier service, telecopier or other telecommunication service shall be interrupted by a cause beyond the control of the parties hereto, then the party sending the Notice shall utilize any service that has not been so interrupted to deliver such Notice. Each party shall provide Notice to the other of any change of address for the purposes hereof. Any Notice may also be given by telephone followed immediately by personal delivery, courier, prepaid mail, telecopier or other telecommunication, and any Notice so given shall be deemed to be given as of the date and time of the telephone notice.

ARTICLE VII - DELIVERY PRESSURE

7.1 Shipper shall pay for all delivery pressure service hereunder in accordance with the provisions of the FT-NR Toll Schedule, List of Tolls and General Terms and Conditions of TransCanada's Transportation Tariff, as each may be amended from time to time.

ARTICLE VIII - MISCELLANEOUS PROVISIONS

8.1 The FT-NR Toll Schedule, the List of Tolls, and the General Terms and Conditions set out in TransCanada's Transportation Tariff, as each may be amended from time to time by the NEB, are all by reference made a part of this Contract and transportation service hereunder shall, in addition to the terms and conditions of this Contract, be subject to the provisions thereof. TransCanada shall notify Shipper at any time that TransCanada files with the NEB revisions to the FT-NR Toll Schedule, the List of Tolls, and/or the General Terms and Conditions (the "Revisions") and shall provide Shipper with a copy of the Revisions.

8.2 The headings used throughout this Contract, the FT-NR Toll Schedule, the List of Tolls and the General Terms and Conditions are inserted for convenience of reference only and are not intended to be considered or taken into account in construing the terms or provisions thereof nor to be deemed in any way to qualify, modify or explain the effect of any such provisions or terms.

8.3 This Contract shall be construed and applied, and be subject to the laws of the Province of Alberta, and, where applicable, the laws of Canada, and shall be subject to the rules, regulations and orders of any regulatory or legislative authority having jurisdiction.

8.4 This Contract, including the Exhibit "A" ~~and Exhibit "B"~~ Addendum~~s~~ attached hereto, each Exhibit "A" Addendum ~~and each Exhibit "B" Addendum~~ entered into from time to time by the parties, and all terms, conditions and provisions incorporated herein by reference, constitute the entire agreement between the parties pertaining to the subject matter hereof and supersedes all prior agreements, representations and understandings, written or oral, pertaining thereto. Except as otherwise provided for herein, no modification, amendment or variation to this Contract shall be effective unless such modification, amendment or variation is in writing and signed by both parties hereto.

IN WITNESS WHEREOF the parties hereto have executed this Contract as of the date written above.

Shipper:		TransCanada PipeLines Limited:	
By:	______________________	By:	______________________
Title:	______________________	Title:	______________________
By:	______________________	By:	______________________
Title:	______________________	Title:	______________________

EXHIBIT "A" ADDENDUM **Page_____of_____**

Non Renewable Firm Transportation Service Contract Addendum

This Exhibit "A" Addendum, made as of the _______ day of __________________, 200____, to the ~~Short Term~~ **Non Renewable** Firm Transportation Service Contract made as of the _____ day of ____________, 200_, between TransCanada PipeLines Limited ("TransCanada") and ____________________ ("Shipper").

System Segment ____

The Delivery Point hereunder is the point of interconnection between the pipeline facilities of TransCanada and __________________ which is located at or near __________________.

The Receipt Point hereunder is the point of interconnection between the pipeline facilities of TransCanada and __________________ which is located at or near __________________.

FT-NR Service Period: __________________________________

Maximum Daily Quantity: __________ GJ Minimum Daily Quantity: __________ GJ

FT-NR Bid Price ($/ GJ/day, maximum 2 decimal places): _____________.

Shipper Contact

Name: ____

Address: ____

____

Telephone: ________________________ Telecopy : ___________________

Dated this __________ day of ______________________________, 200___.

Shipper:		TransCanada PipeLines Limited:	
By:	____________________	By:	____________________
Title:	____________________	Title:	____________________
By:	____________________	By:	____________________
Title:	____________________	Title:	____________________

~~**EXHIBIT "B" ADDENDUM**~~ ~~PAGE 1 OF 1~~

~~Shipper Contact~~

~~Name~~ ______________________ ~~Address~~ ______________________

~~Telephone~~ ______________________ ______________________

~~Telecopy~~ ______________________ ______________________

~~Arched Service Pilot Period (Block Period)~~ ______________________

~~Maximum Daily Quantity Requested **(Required)**~~ ______________________ ~~GJ/day~~

~~Minimum Daily Quantity **(Optional)**~~ ______________________ ~~1 GJ/day~~

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 1

REVENUE REQUIREMENT
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

LINE NO.	PARTICULARS		2003 ACTUAL		SCHEDULE REFERENCE
	(a)	(b)	(c)		
1	Transmission By Others		360,015	I	2.2
2	Storage Operating Costs		11,371	I	3.2
3	Pipeline Integrity and Insurance Deductible Costs		45,200	I	4.0
4	NEB Cost Recovery		10,732		
5	Return		789,692	I	5.2
6	Income Taxes		184,030	I	6.2
7	Depreciation		419,834	I	7.2
8	Inventory Management Program		12,000		8.0
9	Gas Related and Electric Costs		72,847	I	9.2
10	Municipal and Provincial Capital Taxes		115,741	I	10.0
11	Regulatory Amortizations		(69,141)		11.2
12	Gain on Sale of Storage Gas		(953)		12.0
13	Operations, Maintenance and Administrative		228,107	I	13.0
14	Debt Redemption Costs / (Gains)		5,788		15.2
15	Regulatory Proceeding Costs		2,490	I	16.0
16	Pressure Charges		3,772		
17	Gross Revenue Requirement		2,191,525	I	
	Miscellaneous Revenue				
18	Non Discretionary Miscellaneous Revenue		(66,117)	I	
19	Discretionary Miscellaneous Revenue		(251,794)	I	
20	Total Miscellaneous Revenue		(317,911)	I	
21	Net Revenue Requirement		1,873,614	I	

I Updated to reflect 2003 actual costs.

REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS		2004 TEST YEAR		SCHEDULE REFERENCE
	(a)	(b)	(c)		
1	Transmission By Others		355,397		2.3
2	Storage Operating Costs		12,176		3.3
3	Pipeline Integrity and Insurance Deductible Costs		31,710	l	4.0
4	NEB Cost Recovery		12,785	l	
5	Return		780,075	l	5.3
6	Income Taxes		217,412	l	6.3
7	Depreciation		415,160	l	7.3
8	Inventory Management Program		8,000		8.0
9	Gas Related and Electric Costs		67,277		9.3
10	Municipal and Provincial Capital Taxes		118,772	l	10.0
11	Regulatory Amortizations		(68,526)	l	11.3
12	Operations, Maintenance and Administrative		215,398	l	13.0
14	Debt Redemption Costs / (Gains)		(41,601)		15.3
15	Regulatory Proceeding Costs		3,100		16.0
16	Pressure Charges		4,526	l	
17	Gross Revenue Requirement		2,131,661	l	
	Miscellaneous Revenue				
18	Non Discretionary Miscellaneous Revenue		(70,536)	l	
19	Discretionary Miscellaneous Revenue		(279,735)	l	
20	Total Miscellaneous Revenue		(350,271)	l	
21	Net Revenue Requirement		1,781,390	l	

l Updated to reflect the impact of 2003 actuals on opening balances for 2004, the Board's Final Notice for 2004 NEB Cost Recovery, and adjustments to insurance deductible, regulatory amortizations, OM&A, tax rates, and miscellaneous revenue as a result of changes to the 2004 Revenue Requirement.

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 2

TRANSMISSION BY OTHERS

Great Lakes Gas Transmission Company

Service Agreements between TransCanada and Great Lakes Gas Transmission Company (Great Lakes) for the 2004 Test Year provide for combined annual average demand entitlement to TransCanada of 1,321,965 Dth per day (1,305 MMcf per day). TransCanada also holds a long-term Winter Firm Service contract for 50,650 Dth per day (50 MMcf per day) and an interruptible service contract for 455,850 Dth per day (450 MMcf per day).

Great Lakes' TBO costs for 2004 are shown on Schedule 2.3. Great Lakes' rates reflect its five-year rate settlement approved by the Federal Energy Regulatory Commission (FERC) under Docket No. RP00-428, commencing November 1, 2000.

Base year 2002 and actual 2003 costs are shown on Schedules 2.1 and 2.2 respectively.

TransCanada's principal service agreement on Great Lakes is a contract for firm transportation of approximately 1305 MMcfd (FT004), which expires on October 31, 2005. TransCanada notified Great Lakes on April 30, 2003 that TransCanada has elected to exercise its rights under the Right of First Refusal (ROFR) provisions within the Great Lakes tariff. Great Lakes and TransCanada are currently in the final stage of the ROFR process, whereby TransCanada may either submit an acceptable bid or match an another party's acceptable bid on any or all of the FT004 capacity. TransCanada's ROFR on the FT004 capacity will terminate on October 31, 2004.

Union Gas Limited

In 2004 TransCanada will hold M12 contracts of 355,013 GJ/d from Dawn to Parkway and 1,175,488 GJ/d from Dawn to Kirkwall.

In addition TransCanada's westerly entitlement under Union's Rate Schedule C-1 (Parkway to Kirkwall) is 128,316 GJ/d for 2004.

The Union TBO costs for 2004 are shown on Schedule 2.3 and reflect Union's M-12 rates currently in effect under OEB Order RP-2002-0130. In May 2003, Union Gas filed an application with the OEB (RP-2003-0063) for a change in rates to be effective January 2004. The hearing before the OEB commenced in October and the decision is pending.

Union Gas M-12 contract volumes and associated costs formerly included under FST Replacement Costs (Dawn to Parkway and Dawn to Kirkwall) have now been included under Union Gas Transmission by Others costs. Commencing in 2004, the FST Replacement Cost component of the Revenue Requirement has been reclassified to 'Storage Operating Costs' (see Tab 3) which now reflects costs associated with storage activities only. Base Year 2002 and Actual Year 2003 costs have also been realigned to reflect this change in presentation as shown on Schedules 2.1 and 2.2 respectively.

Trans Quebec & Maritimes Pipeline

The TBO cost included for the transportation on Trans Quebec & Maritimes Pipeline (TQM) shown on Schedule 2.3 is a forecast of TQM's Net Revenue Requirement for the Test Year 2004.

TBO Cost Changes

The overall reduction in TBO costs between 2002 and 2003 is principally due to the strengthening of the Canadian dollar against the US dollar and is reflected in lower foreign exchange costs on Great Lakes Gas Transmission payments.

The overall decrease in TBO costs between the 2003 Actuals and the 2004 Test Year is principally due to a further anticipated strengthening of the Canadian dollar relative to the US dollar in 2004 associated with Great Lakes costs. This decrease is partially offset by non-recurring 2003 credits associated with the assignments of Great Lakes capacity.

TRANSMISSION BY OTHERS
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003

LINE NO.	PARTICULARS		RATES	VOLUME	2003 ACTUAL YEAR	
	(a)		(b)	(c)	(d)	
	Great Lakes Gas Transmission L.P.		$US	Dth	($000)	
	From Emerson Firm -					
1		FT Eastern Demand (January to March)	10.278	1 362 485	42,011	
2		FT Eastern Demand (April to October)	10.278	1 311 835	94,381	
3		FT Eastern Demand (November to December)	10.278	1 362 485	28,007	
4		Subtotal			164,399	
5		FT Eastern Commodity	0.01080	397 514 619	4,293	I
6		Eastern ACA Charge	0.00210	397 514 619	835	I
7		Subtotal			5,128	I
8		Total Eastern			169,527	I
	From Emerson Firm -					
9		FT Central Demand January to December	5.759	10 130	700	
10		FT Central Commodity	0.00616	18 885 000	116	I
11		Central ACA Charge	0.00210	18 885 000	40	I
12		Total Central			856	I
13	Force Majeure Credit				(302)	
14	Sub Total ($US)				170,081	I
15	Foreign Exchange (Annual Average)		38.368%		65,257	I
16	GLGT Payments ($CDN)				235,338	I
17	Assignments				(4,523)	I
18	Total Great Lakes Gas Transmission				230,815	I
	Union Gas Limited		$CDN	GJ	($000)	
19	M12 From Dawn -	Demand - Parkway Jan. - Jun.	2.54700	226 814	3,466	
20		Demand - Parkway Jul. - Oct.	2.49000	226 814	2,259	
21		Demand - Parkway Nov. - Dec.	2.49000	355 013	1,768	
22		Demand - Kirkwall Jan. - Jun.	2.12200	1,197,940	15,252	
23		Demand - Kirkwall Jul. - Oct.	2.07400	1,197,940	9,938	
		Demand - Kirkwall Nov. - Dec.	2.07400	1,175,488	4,876	
24		Subtotal			37,559	
25	C1 From Parkway	Demand - Kirkwall Jan. - Jun.	0.59900	128 316	461	
		Demand - Kirkwall Jul. - Dec.	0.58600	128 316	451	
26		Commodity - Kirkwall Jan. - Jun.	0.03100	8 860 153	275	
		Commodity - Kirkwall Jul. - Dec.	0.03800	8 986 863	342	I
27		Subtotal			1,529	I
28	Sub Total				39,088	I
29	Overrun Charges				4,490	I
30	Less Interruptible Margin Rebate				(110)	
31	Rate Refunds and Deferral Account Disposition				(1,724)	
32	Total Union Gas				41,744	I
	TQM Inc.				($000)	
33	TQM Toll				87,526	
34	TQM Refund				(70)	
35	Total TQM				87,456	
36	Total Transmission by Others				360,015	I

I Updated to reflect 2003 actual costs.

TRANSMISSION BY OTHERS
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS		RATES	VOLUME	2004 TEST YEAR
	(a)		(b)	(c)	(d)
	Great Lakes Gas Transmission L.P.		$US	Dth	($000)
	From Emerson Firm -				
1		FT Eastern Demand (January to March)	10.278	1 362 485	42,011
2		FT Eastern Demand (April to October)	10.278	1 311 835	94,381
3		FT Eastern Demand (November to December)	10.278	1 362 485	28,007
4		Subtotal			164,399
5		FT Eastern Commodity	0.01080	466 217 749	5,035
6		Eastern ACA Charge	0.00220	466 217 749	1,026
7		Subtotal			6,061
8		Total Eastern			170,460
	From Emerson Firm -				
9		FT Central Demand January to December	5.759	10 130	700
10		FT Central Commodity	0.00616	25 320 242	156
11		Central ACA Charge	0.00220	25 320 242	56
12		Total Central			912
13	Sub Total ($US)				171,372
14	Foreign Exchange - GLGT Payments @ $1.3158				54,119
15	Total Great Lakes Gas Transmission				225,491
	Union Gas Limited (1)		$CDN	GJ	($000)
16	M12 From Dawn -	Demand - Parkway Jan - Dec	2.49000	355 013	10,608
17		Demand - Kirkwall Jan - Dec I	2.07400	1,175,488	29,256
18		Subtotal			39,864
19	C1 From Parkway	Demand - Kirkwall Jan - Dec	0.58600	128 316	902
20		Commodity - Kirkwall Jan. - Dec.	0.03800	17 107 594	650
21		Subtotal			1,552
22	Sub Total				41,416
23	Overrun Charges				2,600
24	Less Interruptible Margin Rebate				(110)
25	Total Union Gas				43,906
	TQM Inc. (2)				($000)
26	TQM Toll				86,000
27	Total Transmission by Others				355,397

(1) Rates per O.E.B. ORDER # RP-2002-0130
(2) TQM's COS estimate for 2004

I Adjustment to description of contract time period.

2004 Mainline Tolls and Tariff Application
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REVENUE REQUIREMENT
TAB 3

STORAGE OPERATING COSTS

General

Storage operating cost includes the costs of upstream storage arrangements and gas balancing agreements. Base year, actual year and test year costs are shown on Schedules 3.1, 3.2, and 3.3 respectively.

Storage Costs

Storage, or a comparable service, is required for linepack and imbalance management purposes. It provides TransCanada with the ability to operate at closer to optimum linepack levels resulting in a more fuel efficient operation. Storage service also enhances the availability of capacity for rapid increases in transportation demand and supports the fuel recovery process.

In the RH-1-2002 Mainline Tolls Application, TransCanada submitted that it anticipated a need to hold upstream storage capacity of approximately 7 PJ on a continuing basis. In 2003, TransCanada's contracted capacity totaled 9385 TJ, of which 8532 TJ expired on October 31, 2003, with an option to extend to March 31, 2004. The remaining 853 TJ of storage space is under contract until October 31, 2004. In January 2003, TransCanada provided notice to EnCana Gas Storage that it would be extending 6147 TJ of its contracted storage space to March 31, 2004, providing a total of 7000 TJ (6147 TJ + 853 TJ) of storage space during this period.

For service beyond March 31, 2004, TransCanada conducted a Request for Proposals (RFP) for Firm Upstream Storage Service and / or Firm Load Balancing Service. As a result of the RFP process and the continuing need for anticipated storage capacity requirements, TransCanada has contracted for 7 PJ of capacity with EnCana Gas Storage, with minimum daily injections of 250 TJ and a maximum daily withdrawal of 150 TJ, in accordance with contract amendments commencing April 1, 2004. The arrangement is for 5 years and will expire March 31, 2009. The service is priced on a demand/commodity basis. The demand component will change annually in accordance with the Consumer Price Index throughout the five-year term of the contract. The commodity component is payable on injection only.

Storage service was originally contracted due to the conversion of Firm Service Tendered (FST) contracts to Firm Transportation (FT) contracts starting November 1998. At that time, TransCanada determined that upstream and downstream storage / load balancing services, together with related transportation services, was the most efficient method of replacing the flexibility provided by FST service. That flexibility provided TransCanada with the ability to meet its seasonal obligations, the ability to minimize the impact of planned and unplanned outages on its shippers, as well as the ability to manage its linepack and system imbalances effectively. Since the original storage contracts were entered into, the downstream storage and related transportation arrangements expired and were not renewed by TransCanada due to the reduction of firm contracts on the Mainline.

The table below is a summary of the storage related costs since the FST conversion in 1998. The data illustrates the reduction in costs recovered in TransCanada's revenue requirement and the benefit to shippers as a result of the expiry of the downstream storage arrangements.

Table 3-1 - Mainline Storage Costs:

	Storage Operating Costs ($000)
1998	3,627
1999	22,335
2000	23,311
2001 (1)	21,494
2002 (2)	10,956
2003 Actual (3)	11,371
2004 Forecast (4)	12,176

(1) Reflects storage arrangements with ANR terminating October 31, 2001
(2) Reflects load balancing arrangement with Enbridge expiring October 31, 2002
(3) Reflects 9,385 TJ of contracted EnCana storage space from January 1, 2003 to October 31, 2003 and 7,000 TJ of space from November 1, 2003 to December 31, 2003
(4) Reflects a new storage arrangement with EnCana effective April 1, 2004

Balancing Agreements

The Gas Balancing Agreement with NOVA Gas Transmission Ltd. (NGTL), to accommodate upstream storage, costs $1.0 million per year.

Union Gas Transportation

Union Gas M-12 contract volumes and associated costs formerly included under FST Replacement Costs (Dawn to Parkway and Dawn to Kirkwall) have now been included under Union Gas Transmission by Others costs. Commencing in 2004, the FST Replacement Cost component of the Revenue Requirement has been reclassified to 'Storage Operating Costs' which now reflects costs associated with storage activities only. Base year 2002 and Actual Year 2003 costs have also been realigned to reflect this change in presentation as shown on Schedules 2.1 and 2.2 respectively.

STORAGE OPERATING COSTS
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003

Ln. No.	Particulars	Amount ($000)	
	(a)	(b)	
1	NGTL	1,000	
2	EnCana	10,371	l
3	Total Storage Operating Costs	11,371	l

l Updated to reflect 2003 actual costs.

2004 Mainline Tolls and Tariff Application
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REVENUE REQUIREMENT
TAB 4

PIPELINE INTEGRITY AND INSURANCE DEDUCTIBLE COSTS

PIPELINE INTEGRITY COSTS

Background

TransCanada's record of pipeline safety and service reliability is the direct result of an industry leading Integrity Management Process. This process utilizes state of the art advanced inspection and mitigation technologies applied within a comprehensive risk-based methodology. Risk assessment is used to identify potential integrity threats and initiate inspection/mitigation activities, while results from advanced inspections for known or suspected integrity threats are used to develop specific integrity maintenance activities. The Integrity Management Process provides the basis for developing the annual Pipeline Integrity Program. Using this process, TransCanada is able to achieve excellent levels of safety for all pipeline segments, regardless of pipeline vintage or construction. The Integrity Management Process is similar to the ISO model for quality assurance and is audited internally to ensure the program is followed and effective.

The development of this state of the art process has been an evolution and the current form of the risk assessment tool maximizes the benefit from knowledge gained through previous integrity programs. For example, TransCanada implemented an accelerated integrity program starting in 1999 to address integrity concerns at the time. Since then, TransCanada has conducted repeat inline inspections on sufficient portions of the system to confidently scale back the integrity program to long term sustainable levels.

The Pipeline Integrity Program consists of expense and capital spending required for maintaining the physical integrity of the pipeline system. A list of notable programs follows:

Aerial Surveys:	Aerial surveys of the system, in addition to the regular flights accounted for within operating costs, are required to supplement activities within the Pipeline Integrity Program. Additional surveys allow for more immediate identification of integrity related concerns such as leaks, unauthorized crossings and geotechnical concerns resulting from weather and seasonal variations.
Cathodic Protection:	The cathodic protection program addresses the risk of external corrosion on the pipeline. The program consists of annual monitoring of protection levels as well as associated mitigative actions when deficiencies are identified.
Corrosion:	Activities (other than Cathodic Protection) to address the risk of external corrosion are included in this grouping. The primary activities in this grouping are inline inspection and corrosion excavations.
Geotechnical:	The Geotechnical program two primary components: monitoring and mitigation. Annual monitoring of high risk sites is conducted while in-depth analysis of failed slopes is conducted to ensure that pipeline integrity is not compromised. The models also ensure that any pipe exposure issues are addressed.
Mechanical Damage:	This program has several components including maintaining up-to-date information regarding class locations across the pipeline system. Depths of cover, crossing and associated issues are also addressed through this program.

Other: Several smaller programs are included in this category. For example, the use of transfer compressors for work associated with pipe integrity activities and investigations of dents and sleeves if necessary.

R&D: Numerous research projects directly associated with the pipeline integrity program are underway. The most notable in recent years has been the development of an inline inspection tool capable of detecting Stress Corrosion Cracking (SCC) in gas pipelines. As this technology comes to fruition, savings are anticipated in the SCC component of the Pipeline Integrity program as more detailed information can be collected regarding the state of the pipeline; further, there is the possibility of replacing significant amounts of the hydrotesting program with this technology.

SCC: The SCC threat on the system is primarily addressed through the use of hydrotesting as well as investigative digs. Hydrotesting is necessary to ensure the integrity of specific sections – this technique will be complemented by the availability of an inline inspection tool to detect SCC (as discussed above). The primary focus of the investigative dig program is condition monitoring as well as model validation.

Valve Management: Valve management is focused on ensuring that pipeline isolation is possible in case of pipeline failure as well as during the course of pipeline integrity related work.

While Pipeline Integrity spending levels are dictated by the integrity threats facing the pipeline, TransCanada continues to strive for improvements in both program development and implementation. For example, an increased focus on project management allowed TransCanada to maximize bundling and scheduling opportunities on the 2003 hydrotesting program. This has resulted in savings of approximately 10% relative to the 2003 hydrotesting budget.

Stress Corrosion Cracking (SCC) and Related Costs – (Non Research) (Schedule 4.0, Lines 1 - 3)

The costs associated with the 2004 SCC and Related Costs (Non-Research) are currently estimated to be $12.7 million. This is significantly lower than 2003 costs primarily due to completion of the hydrotesting program initiated after the Brookdale rupture. As the results from this hydrotesting and investigative dig program are analyzed, adjustments to follow on programs are made. Further, the cost of the hydrotesting program fluctuates year to year based on two additional factors. First, SCC susceptible locations are on a location specific retest frequency, thus the number of locations can vary greatly from year to year. Second, final implementation costs will be influenced by the economic environment that exists when the work is tendered.

Pipeline Integrity-Research Costs (Schedule 4.0, Lines 4- 7)

The 2004 Pipeline Integrity Research budget is currently estimated at $1.4 million. SCC tool development represents approximately one third of research costs. TransCanada is working with In-line Inspection vendors to develop new in-line inspection tools to locate cracks in pipelines. SCC model enhancement represents $0.3 million of the total budget. This work involves using the data gathered by various means to improve the models used to predict where SCC is likely to occur. These models are then used to prioritize integrity projects. An additional $0.6 million is estimated for Corrosion and other Integrity research.

This includes research on pipeline repair, external loads/damage and external corrosion.

Corrosion and Other Pipe Integrity Program Costs (Schedule 4.0, Lines 8 - 15)

The Corrosion and Other Pipe Integrity programs for 2004 are estimated to be $16.9 million. This is lower than 2003 by approximately $5.7 million. This reduction is primarily due to the cyclic nature of the program. As with hydrostatic testing, the number of sections to be re-inspected by means of Magnetic Flux Leakage in-line inspection will vary from year to year depending on the re-inspection frequency of different parts of the system. Further, any reduction in inspection levels can have the added impact of reducing excavation work as estimated levels for digs and repairs are a function of the number of kilometers pigged.

The requirements for geotechnical work and cathodic protection programs continue to vary from year to year as environmental conditions change. In 2004 our efforts to address the threat of mechanical damage continue.

Insurance Deductible Costs Schedule 4.0 (lines 17 – 25)

Schedule 4.0 (lines 17 – 25) provides a comparison of the insurance deductible costs for the base year ended December 31, 2002, the actual year ended December 31, 2003 and the test year ending December 31, 2004. The mechanism, as approved in the Board's RH-3-86 Decision, provides for the deferral of insurance deductible costs in the year they are incurred with an amortization to the Revenue Requirement over the next three succeeding years.

PIPELINE INTEGRITY COSTS AND INSURANCE DEDUCTIBLE COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002 AND
ACTUAL YEAR ENDED DECEMBER 31, 2003 AND
TEST YEAR ENDING DECEMBER 31, 2004
($000)

Ln. No.	Particulars	2002 Base Year	Change	2003 Actual Year		Change	2004 Test Year	
	(a)	(b)	(c)	(d)		(e)	(f)	
	SCC and Related Costs (Non-Research)							
1	SCC ILI, Excavation and Investigations	169	6,170	6,339	I	(2,412)	3,927	
2	Hydrostatic Retest and Other	12,805	673	13,478	I	(4,693)	8,785	
3	Total SCC and Related Costs	12,974	6,843	19,817	I	(7,105)	12,712	
	Pipeline Integrity - Research							
4	SCC Tool Development	(733)	1,802	1,069	I	(579)	490	
5	SCC Model Enhancement	1,017	(612)	405	I	(86)	319	
6	Corrosion and Other Integrity Related Research	0	647	647	I	(34)	613	
7	Total Pipeline Integrity - Research	284	1,837	2,121	I	(699)	1,422	
	Corrosion and Other Pipe Integrity Programs							
8	Internal Inspection	3,747	7,758	11,505	I	(4,759)	6,746	
9	Non-SCC Investigative/Excavation Program	4,118	2,066	6,184	I	(2,145)	4,039	
10	Cathodic Protection Programs	3,251	389	3,640	I	10	3,650	
11	Mechanical Damage	271	(42)	229	I	745	974	
12	Geotechnical	316	122	438	I	(180)	258	
13	Valve Program	44	42	86	I	95	181	
14	Other	571	(44)	527	I	571	1,098	
15	Total Corrosion and Other Pipeline Integrity Programs	12,318	10,291	22,609	I	(5,663)	16,946	
16	Total Pipeline Integrity Costs	25,576	18,971	44,547	I	(13,467)	31,080	
	Insurance Deductible							
17	1999 Costs	179						
18	2000 Costs	6		6				
19	2001 Costs	438		438			438	
20	2002 Costs			1,320	I		1,320	I
21	2003 Costs						32	I
22	Total Three Year Cost	623		1,764	I		1,790	I
23	Flow-Through Amount (1/3 of Three Year Total)	207		587	I		597	
24	Adjustment resulting from prior period Liability Claim	78		66	I		33	I
25	Total Insurance Deductible	285		653	I		630	I
26	Total Pipeline Integrity and Insurance Deductible Costs	25,861		45,200	I		31,710	I

I Updated to reflect 2003 actual costs, and the impact of insurance deductible costs on the 2004 amortization.

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REVENUE REQUIREMENT
TAB 5

RATE BASE

Schedule 5.1

Schedule 5.1 provides a summary of the average rate base and return for the base year ended December 31, 2002.

Schedule 5.1.1

Schedule 5.1.1 provides the monthly balances of gas plant in service as booked by plant account for the base year ended December 31, 2002.

Schedule 5.1.2

Schedule 5.1.2 provides the monthly balances of accumulated depreciation and amortization as booked by plant account for the base year ended December 31, 2002.

Schedule 5.1.3

Schedule 5.1.3 provides the monthly balances by plant account for contributions in aid of construction for the base year ended December 31, 2002.

Schedule 5.1.4

Schedule 5.1.4 provides the calculation of the allowance for cash working capital and GST for the base year ended December 31, 2002. The cash working capital allowance was computed by deducting from operation and maintenance expense, those costs which relate to non-funded pension and post employment expenses and insurance expense.

Schedule 5.1.5

Schedule 5.1.5 provides the monthly balances for materials and supplies for the base year ended December 31, 2002. Inventory transferred to the Inventory Management Program is not included in these balances.

Schedule 5.1.6

Schedule 5.1.6 provides the monthly balances of transmission linepack and transmission storage gas for the base year ended December 31, 2002.

Schedule 5.1.7

Schedule 5.1.7 provides the monthly balances of prepaid insurance for the base year ended December 31, 2002.

Schedule 5.1.8

Schedule 5.1.8 provides the average unamortized regulatory deferred balances for the base year ended December 31, 2002.

Schedule 5.2

Schedule 5.2 provides a summary of average rate base and return for the actual year ended December 31, 2003.

Schedule 5.2.1

Schedule 5.2.1 provides the monthly balances and the average of the thirteen monthly balances of gas plant in service as projected for the actual year ended December 31, 2003 by plant account.

Schedule 5.2.2

Schedule 5.2.2 provides the projection of the monthly balances of accumulated depreciation and amortization for the actual year ended December 31, 2003, based on the monthly gross plant balances shown on schedule 5.2.1 using depreciation rates as noted on Schedule 7.2 .

Schedule 5.2.3

Schedule 5.2.3 provides the monthly balances by plant account of contributions in aid of construction for the actual year ended December 31, 2003.

Schedule 5.2.4

Schedule 5.2.4 provides the calculation of the allowance for cash working capital and GST for the actual year ended December 31, 2003. The cash working capital allowance was computed by deducting from projected operation and maintenance expense, those costs which relate to non-funded pension and post employment expenses, and insurance expense.

Schedule 5.2.5

Schedule 5.2.5 provides the monthly balances for materials and supplies for the actual year ended December 31, 2003. Inventory transferred to the Inventory Management Program is not included in these balances.

Schedule 5.2.6

Schedule 5.2.6 provides the monthly balances of transmission linepack and transmission storage gas for the actual year ended December 31, 2003.

Schedule 5.2.7

Schedule 5.2.7 provides the monthly balances of prepaid insurance for the actual year ended December 31, 2003.

Schedule 5.2.8

Schedule 5.2.8 provides the average unamortized regulatory deferred balances for the actual year ended December 31, 2003.

Schedule 5.3

Schedule 5.3 provides a summary of average rate base and return for the test year ending December 31, 2004.

Schedule 5.3.1

Schedule 5.3.1 provides the monthly balances and the average of the thirteen monthly balances of gas plant in service as projected for the test year ending December 31, 2004 by plant account.

The starting point in this computation is the cost of the gas plant in-service as recorded in the accounts at December 31, 2001. A three year continuity of additions and retirements shown on Sheets 3 through 16 of 17 include:

(1) Plant recorded as GPUC as at December 31, 2001 and not in service at that time but which were placed in service during 2002.

(2) Other required plant additions and deletions between January 1, 2002 and December 31, 2004.

(3) Plant additions include the estimated cost to complete the construction of such plant and have been included based on projected First Devoted to

Public Service (FDPS) dates. An amount for Allowance for Funds Used During Construction (AFUDC) and capitalized overhead has also been included.

In 2004, TransCanada is projecting plant expenditures of approximately $31.8 million in maintenance capital, $1.2 million in capacity capital, and $10.8 million in general plant.

Schedule 5.3.2

Schedule 5.3.2 provides the projection of the monthly balances of accumulated depreciation and amortization for the test year ending December 31, 2004, based on the monthly gross plant balances shown on schedule 5.3.1 using depreciation rates as noted on Schedule 7.3 .

The average balances of accumulated depreciation and amortization of gross plant have been computed by adding depreciation and amortization expense for the period January 1, 2002 through to December 31, 2004, calculated as set out in Revenue Requirement Tab 7 of this Application, to the balance at December 31, 2001. In addition, the adjustments for retirements in the period January 1, 2002 to December 31, 2004 have also been included. This treatment is in accordance with the GPUAR (Gas Pipeline Uniform Accounting Regulations).

There is an estimated $24 million of retirement work scheduled for 2004. These costs are primarily related to the decommissioning of compressor station facilities that have been identified in the Onshore Pipeline Regulations Section 44 application dated July 5, 2001.

Schedule 5.3.3

Schedule 5.3.3 provides the monthly balances by plant account of contributions in aid of construction for the test year ending December 31, 2004. These balances reflect the amortization computed in accordance with NEB Order TG-6-84, together with the forecasted additional contributions.

The Test Year includes estimated capital costs of $5.5 million to be recovered from the Ministry of Transportation of Ontario arising from the need to relocate the pipeline as a result of the twinning of Highway #11 near station 119, Sunridge.

Schedule 5.3.4

Schedule 5.3.4 provides the calculation of the allowance for cash working capital and GST for the test year ending December 31, 2004. The cash working capital allowance was computed by deducting from projected operation and maintenance expense, those costs which relate to non-funded pension and post employment expenses, and insurance expense.

Schedule 5.3.5

Schedule 5.3.5 provides the monthly balances for materials and supplies for the test year ending December 31, 2004.

Schedule 5.3.6

Schedule 5.3.6 provides the monthly balances of transmission linepack and transmission storage gas for the test year ending December 31, 2004.

Schedule 5.3.7

Schedule 5.3.7 provides the monthly balances of prepaid insurance for the test year ending December 31, 2004.

Schedule 5.3.8

Schedule 5.3.8 provides the average unamortized regulatory deferred balances for the test year ending December 31, 2004.

AVERAGE RATE BASE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

LINE NO.	PARTICULARS	TOLLS AMOUNT		SCH. REF.
	(a)	(b)		(c)
	Utility Investment			
1	Gross Plant	12,378,751	I	5.2.1
2	Accumulated Depreciation	(3,952,065)	I	5.2.2
3	Net Plant	8,426,686	I	
4	Contributions in Aid of Construction	(23,220)	I	5.2.3
5	Total Plant	8,403,466	I	
	Working Capital			
6	Cash	23,215	I	5.2.4
7	Goods & Services Tax, Net	(5,585)	I	5.2.4
8	Materials and Supplies	30,133	I	5.2.5
9	Transmission Linepack	42,834		5.2.6
10	Storage Gas	16,194		5.2.6
11	Prepayments and Deposits	1,976	I	5.2.7
12	Total Working Capital	108,767	I	
	Deferred Costs			
13	Miscellaneous Deferred Items	45,385		5.2.8
14	Operating and Debt Service Deferrals	(29,136)		5.2.8
15	Surplus Pension/Post Employment Benefits	27,231	I	5.2.8
16	Total Deferred Costs	43,480	I	
17	Total Rate Base	8,555,713	I	
18	Return @ 9.23%	789,692	I	

I Updated to reflect 2003 actual balances.

TransCanada
In business to deliver

PROJECTED UTILITY INVESTMENT
GAS PLANT IN SERVICE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

LINE NO.	PARTICULARS	JAN 01	JAN 31	FEB 28	MARCH 31	APRIL 30	MAY 31	JUNE 30
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Intangible Plant	8,567	8,567	8,567	8,567	8,567	8,567	8,567
	Transmission Plant							
2	Land	7,673	7,673	7,673	7,673	7,673	7,937	7,937
3	Land Rights	33,158	33,158	33,158	33,158	33,158	33,158	33,158
4	Mains	8,693,798	8,701,366	8,701,363	8,701,329	8,702,864	8,702,922	8,704,064
5	Compressor	3,281,328	3,283,447	3,283,403	3,283,674	3,281,917	3,281,879	3,281,363
6	Measuring and Regulating	110,636	110,658	110,661	110,676	110,652	110,656	110,749
7	Communication Equipment - Transmission	13,414	13,471	13,471	13,471	13,471	13,471	13,471
	General Plant							
8	Structures and Improvements	12,609	12,609	12,609	12,609	12,609	12,609	12,611
	Furniture and Equipment							
9	General	7,693	7,693	7,693	7,693	7,692	7,692	7,692
10	Computers	125,675	126,215	126,707	127,290	127,810	128,188	128,566
	Transportation Equipment							
11	Vehicles	9,910	8,201	8,201	8,249	8,314	8,315	8,315
12	Patrol Aircraft	870	870	870	870	870	870	870
13	Heavy Work Equipment	22,749	22,750	22,759	22,759	22,761	22,770	22,776
14	Tools and Work Equipment	28,596	28,615	28,615	28,615	28,615	28,583	28,596
15	Communication Equipment - General	7,839	7,839	7,839	7,839	7,839	7,838	7,838
16	Total Gas Plant In Service	12,364,516	12,373,132	12,373,590	12,374,472	12,374,812	12,375,455	12,376,573
17	AFUDC and Overhead	0	0	0	0	0	0	0
18	Construction Warehouse	2,745	2,758	2,758	2,724	2,705	2,705	2,647
19	Net Gas Plant In Service	12,367,261	12,375,890	12,376,348	12,377,196	12,377,517	12,378,160	12,379,220

No change from 2003 Forecast.

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PROJECTED UTILITY INVESTMENT
GAS PLANT IN SERVICE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

LINE NO.	PARTICULARS	JULY 31	AUG 31	SEPT 30	OCT 31	NOV 30	DEC 31	AVERAGE	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Intangible Plant	8,567	8,567	8,567	8,567	8,567	8,567	8,567	
	Transmission Plant								
2	Land	7,937	7,937	7,937	7,937	7,970	7,970	7,841	I
3	Land Rights	33,159	33,159	33,159	33,159	33,159	33,159	33,159	I
4	Mains	8,704,446	8,704,789	8,705,775	8,705,872	8,707,769	8,708,037	8,703,415	I
5	Compressor	3,284,142	3,284,124	3,285,268	3,286,341	3,286,952	3,289,025	3,284,067	I
6	Measuring and Regulating	110,750	110,710	110,257	110,257	109,996	109,996	110,512	I
7	Communication Equipment - Transmission	13,609	13,612	13,612	13,612	13,612	13,963	13,558	I
	General Plant								
8	Structures and Improvements	12,611	12,626	12,628	12,627	12,627	12,628	12,617	I
	Furniture and Equipment								
9	General	7,692	7,692	7,692	7,692	7,692	6,194	7,577	
10	Computers	128,604	128,757	129,114	129,322	129,769	102,504	126,040	I
	Transportation Equipment								
11	Vehicles	8,315	8,315	8,315	8,578	9,013	9,335	8,567	I
12	Patrol Aircraft	870	870	870	870	870	870	870	
13	Heavy Work Equipment	22,790	22,791	22,795	22,870	22,880	22,949	22,800	I
14	Tools and Work Equipment	28,598	28,598	28,624	28,578	28,703	27,692	28,541	I
15	Communication Equipment - General	7,838	8,093	8,093	8,093	8,093	8,093	7,936	I
16	Total Gas Plant In Service	12,379,926	12,380,639	12,382,705	12,384,373	12,387,671	12,360,982	12,376,065	
17	AFUDC and Overhead	0	0	0	0	0	0	0	I
18	Construction Warehouse	2,647	2,647	2,647	2,647	2,647	2,638	2,686	I
19	Net Gas Plant In Service	12,382,573	12,383,286	12,385,352	12,387,020	12,390,318	12,363,620	12,378,751	I

I Updated to reflect 2003 actual costs.

ANALYSIS OF GPUC
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

		DIRECT COSTS					TRANSFERS TO G.P.I.S.					
LINE NO.	PARTICULARS	INCURRED	TRANSFERS TO GPIS	AFUDC BASE	AFUDC CAPITALIZED	OVERHEAD CAPITALIZED	AFUDC	OVERHEAD	OTHER TRANSFERS	PROJECTED G.P.U.C. BALANCE	13 MONTH AVERAGE	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	December 2002								0	15,036		
2	January	(673)	(9,490)	9,917	66	24	(204)	(101)	0	4,660		
3	February	1,533	(723)	5,068	33	23	(5)	(16)	0	5,505		
4	March	1,927	(357)	6,298	42	22	(1)	(6)	0	7,132		
5	April	3,085	(3,134)	7,079	52	81	(35)	(137)	0	7,045		
6	May	1,495	(360)	7,640	58	62	(10)	(6)	0	8,284		
7	June	3,111	(1,450)	9,116	68	41	(36)	(37)	0	9,982		
8	July	2,442	(3,255)	9,574	72	36	(122)	(39)	0	9,116		I
9	August	2,031	(628)	9,819	72	6	(1)	(2)	0	10,593		I
10	September	2,524	(2,815)	10,448	80	27	(53)	(27)	0	10,330		I
11	October	1,596	(1,220)	10,537	78	68	(58)	(29)	0	10,765		I
12	November	2,870	(2,446)	11,385	86	1,595	(55)	(780)	0	12,037		I
13	December	2,702	(2,638)	11,919	83	(20)	(57)	(278)	0	11,828		I
14	Total 2003	24,643	(28,517)		792	1,967	(636)	(1,457)	0		9,409	I

I Updated to reflect 2003 actual costs.

PROJECTED UTILITY INVESTMENT
ACCUMULATED DEPRECIATION AND AMORTIZATION
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

LINE NO.	PARTICULARS	JAN 01	JAN 31	FEB 28	MARCH 31	APRIL 30	MAY 31	JUNE 30
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Intangible Plant	5,954	5,972	5,989	6,007	6,024	6,042	6,059
	Transmission Plant							
2	Land	0	0	0	0	0	0	0
3	Land Rights	11,024	11,100	11,175	11,251	11,326	11,402	11,477
4	Mains	2,934,917	2,955,368	2,975,476	2,995,822	3,016,234	3,036,686	3,057,138
5	Compressor	709,195	719,660	730,135	740,395	747,463	758,293	768,409
6	Measuring and Regulating	34,551	34,905	35,257	35,609	35,962	36,314	36,666
7	Communication Equipment - Transmission	8,847	8,910	8,974	9,038	9,102	9,166	9,230
	General Plant							
8	Structures and Improvements	2,235	2,089	2,346	2,399	2,452	2,505	2,558
	Furniture and Equipment							
9	General	(3,056)	(2,982)	(2,909)	(2,836)	(2,763)	(2,690)	(2,617)
10	Computers	32,437	35,220	38,013	40,819	43,637	46,467	49,305
	Transportation Equipment							
11	Vehicles	878	885	973	1,062	1,141	1,221	1,300
12	Patrol Aircraft	1,580	1,580	1,580	1,580	1,580	1,580	1,580
13	Heavy Work Equipment	9,098	9,133	9,169	9,204	9,239	9,259	9,294
14	Tools and Work Equipment	10,793	10,880	10,967	11,054	11,141	11,215	11,302
15	Communication Equipment - General	4,270	4,292	4,313	4,335	4,356	4,378	4,399
16	Total Accumulated Depreciation	3,762,724	3,797,011	3,831,460	3,865,738	3,896,895	3,931,836	3,966,101
17	AFUDC and Overhead	0	0	0	0	0	0	0
18	Net Accumulated Depreciation	3,762,724	3,797,011	3,831,460	3,865,738	3,896,895	3,931,836	3,966,101
19	Retirement Work In Progress	(9,144)	(8,683)	(9,094)	(8,504)	(8,328)	(8,616)	(9,002)
20	Accumulated Depreciation	3,753,579	3,788,329	3,822,366	3,857,233	3,888,566	3,923,220	3,957,099

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PROJECTED UTILITY INVESTMENT
ACCUMULATED DEPRECIATION AND AMORTIZATION
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

LINE NO.	PARTICULARS	JULY 31	AUGUST 31	SEPT 30	OCT 31	NOV 30	DEC 31	AVERAGE	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Intangible Plant	6,076	6,094	6,111	6,129	6,146	6,164	6,059	
	Transmission Plant								
2	Land	0	0	0	0	0	0	0	
3	Land Rights	11,553	11,628	11,703	11,779	11,854	11,930	11,477	
4	Mains	3,077,550	3,097,916	3,118,284	3,138,702	3,158,726	3,179,158	3,057,075	I
5	Compressor	779,214	789,924	800,961	810,528	821,156	831,841	769,783	I
6	Measuring and Regulating	37,019	37,333	37,232	37,583	37,673	38,023	36,471	I
7	Communication Equipment - Transmission	9,294	9,359	9,423	9,488	9,553	9,617	9,231	I
	General Plant								
8	Structures and Improvements	2,611	2,664	2,717	2,770	2,823	2,876	2,542	I
	Furniture and Equipment								
9	General	(2,544)	(2,471)	(2,398)	(2,325)	(2,221)	(3,646)	(2,728)	I
10	Computers	52,152	54,999	57,850	60,709	63,573	38,859	47,234	I
	Transportation Equipment								
11	Vehicles	1,380	1,460	1,540	1,620	1,702	1,559	1,286	I
12	Patrol Aircraft	1,580	1,580	1,580	1,580	1,580	1,580	1,580	
13	Heavy Work Equipment	9,390	9,425	9,461	9,496	9,532	9,568	9,328	I
14	Tools and Work Equipment	11,389	11,476	11,563	11,650	11,737	10,790	11,227	I
15	Communication Equipment - General	4,420	4,442	4,464	4,486	4,508	4,530	4,399	I
16	Total Accumulated Depreciation	4,001,084	4,035,829	4,070,493	4,104,195	4,138,342	4,142,848	3,964,966	I
17	AFUDC and Overhead	0	0	0	0	0	0	0	
18	Net Accumulated Depreciation	4,001,084	4,035,829	4,070,493	4,104,195	4,138,342	4,142,848	3,964,966	I
19	Retirement Work In Progress	(9,911)	(12,324)	(16,275)	(17,748)	(22,269)	(27,812)	(12,901)	I
20	Accumulated Depreciation	3,991,173	4,023,505	4,054,218	4,086,447	4,116,073	4,115,036	3,952,065	I

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

		NEB ACCOUNT NUMBERS			
LINE NO.	PARTICULARS	465	467	TOTAL	
	(a)	(b)	(c)	(d)	
1	December 2002	(18,376)	(1,849)	(20,225)	
2	January	(21,925)	(1,841)	(23,765)	
3	February	(21,868)	(1,834)	(23,702)	
4	March	(21,812)	(1,828)	(23,639)	
5	April	(21,755)	(1,759)	(23,514)	
6	May	(21,699)	(1,753)	(23,452)	
7	June	(21,642)	(1,840)	(23,482)	
8	July	(21,585)	(1,791)	(23,377)	I
9	August	(21,529)	(1,785)	(23,314)	I
10	September	(21,667)	(1,779)	(23,446)	I
11	October	(21,610)	(1,772)	(23,382)	I
12	November	(21,553)	(1,766)	(23,318)	I
13	December	(21,486)	(1,759)	(23,246)	I
14	Average in the Actual Year	(21,424)	(1,797)	(23,220)	I

I Updated to reflect 2003 actual costs.

CASH WORKING CAPITAL
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	AMOUNT	
	(a)	(b)	
1	Total Operations, Maintenance and Administrative Expense	279,601	l
	Deduct:		
2	Non-Funded Pension Expense/Post Emp't Benefits (Schedule 5.2.8, Sheet 3 of 4)	(18,541)	l
3	Insurance Expense Net of Deductibles	4,539	l
4	Total Deducts	(14,002)	l
5	Net Operations, Maintenance and Administrative Expense	293,603	l
6	29/365th for Cash Working Capital	23,215	l

l Updated to reflect 2003 actual amounts.

GOODS AND SERVICES TAX, NET
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

LINE NO.	PARTICULARS	GST RECEIVABLE	GST PAYABLE	NET RECEIVABLE/ PAYABLE	REVENUE CANADA SETTLEMENT PAYMENT/(REFUND)	TOTAL	
	(a)	(b)	(c)	(d)	(e)	(f)	
1	December, 2002					(3,379)	
2	January	1,452	(6,746)	(5,294)	3,379	(5,294)	
3	February	1,274	(7,544)	(6,270)	5,294	(6,270)	
4	March	1,019	(8,064)	(7,045)	6,270	(7,045)	
5	April	1,168	(7,429)	(6,261)	7,045	(6,261)	
6	May	840	(6,823)	(5,983)	6,261	(5,983)	
7	June	930	(7,155)	(6,225)	5,983	(6,225)	
8	July	1,264	(7,674)	(6,410)	6,225	(6,410)	
9	August	1,003	(6,690)	(5,687)	6,410	(5,687)	I
10	September	1,352	(6,875)	(5,523)	5,687	(5,523)	I
11	October	1,755	(6,725)	(4,970)	5,523	(4,970)	I
12	November	1,163	(6,593)	(5,430)	4,970	(5,430)	I
13	December	2,111	(6,241)	(4,130)	5,430	(4,130)	I
14	Average in the Year					(5,585)	I

I Updated to reflecte 2003 actual costs.

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MATERIALS AND SUPPLIES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	AMOUNT	
	(a)	(b)	
1	December, 2002	31,813	
2	January	31,348	
3	February	30,554	
4	March	30,357	
5	April	30,059	
6	May	30,064	
7	June	29,843	
8	July	29,637	l
9	August	29,657	l
10	September	29,679	l
11	October	29,887	l
12	November	29,786	l
13	December	29,042	l
14	Average in the Year	30,133	l

l Updated to reflect 2003 actual balances

TRANSMISSION LINEPACK
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
1	December, 2002	42,834
2	January	42,834
3	February	42,834
4	March	42,834
5	April	42,834
6	May	42,834
7	June	42,834
8	July	42,834
9	August	42,834
10	September	42,834
11	October	42,834
12	November	42,834
13	December	42,834
14	Average in the Year	42,834

No Change from 2003 Forecast.

TRANSMISSION STORAGE GAS
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	MONTHLY	TOTAL
	(a)	(b)	(c)
1	December, 2002		19,370
2	January	(1,293)	18,077
3	February	(1,167)	16,910
4	March	(1,293)	15,617
5	April	0	15,617
6	May	0	15,617
7	June	0	15,617
8	July	0	15,617
9	August	0	15,617
10	September	0	15,617
11	October	0	15,617
12	November	0	15,617
13	December	0	15,617
14	Average in the Year		16,194
15	Total Activity	(3,753)	

l No Change from 2003 Forecast.

PREPAYMENTS
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
1	December, 2002	1,753
2	January	1,425
3	February	1,092
4	March	730
5	April	499
6	May	139
7	June	3,736
8	July	3,384
9	August	3,187
10	September	2,982
11	October	2,595
12	November	2,221
13	December	1,944
14	Average in the Year	1,976

l No Change from 2003 Forecast.

REGULATORY DEFERRED COSTS
AVERAGE UNAMORTIZED REGULATORY DEFERRED BALANCES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	AMOUNT INCLUDED IN RATE BASE	SCHEDULE REFERENCE
	(a)	(b)	(c)
	Miscellaneous Deferred Items		
1	Debt, Discount and Expense (Schedule 5.2.8, Sheet 2 of 4)	45,337	
2	Trust Deed Amendment Expense (Schedule 5.2.8, Sheet 2 of 4)	48	
3	Total	45,385	Sched. 5.2 Line 13
4	Operating and Debt Service Deferrals (Schedule 5.2.8, Sheet 4 of 4)	(29,136)	Sched. 5.2 Line 14
5	Non-Funded Pension Expense and Post Employment Benefits (Schedule 5.2.8, Sheet 3 of 4)	27,231 l	Sched. 5.2 Line 15

l Updated to reflect 2003 actual balances.

DEBT, DISCOUNT AND EXPENSE, AND
TRUST DEED AMENDMENT COSTS
AVERAGE UNAMORTIZED BALANCE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	DEBT, DISCOUNT AND EXPENSE	TRUST DEED AMENDMENT EXPENSE	TOTAL
	(a)	(b)	(c)	(d)
1	December, 2002	49,682	54	49,736
2	January	49,408	53	49,461
3	February	49,134	52	49,186
4	March	48,860	51	48,911
5	April	48,587	50	48,637
6	May	48,313	49	48,362
7	June	48,039	48	48,087
8	July	41,881	47	41,928
9	August	41,619	46	41,665
10	September	41,357	45	41,402
11	October	41,095	44	41,139
12	November	40,833	44	40,877
13	December	40,570	43	40,613
14	Average in the Year	45,337	48	45,385

l No change from 2003 Forecast.

(UNFUNDED)/PREFUNDED PENSION LIABILITY AND POST EMPLOYMENT BENEFITS LIABILITY
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

LINE NO.	PARTICULARS	(UNFUNDED)/PREFUNDED PENSION LIABILITY EXPENSE	(UNFUNDED)/PREFUNDED PENSION LIABILITY FUNDING	(UNFUNDED)/PREFUNDED PENSION LIABILITY TOTAL	POST EMPLOYMENT BENEFITS LIABILITY EXPENSE	POST EMPLOYMENT BENEFITS LIABILITY ACTUAL	POST EMPLOYMENT BENEFITS LIABILITY TOTAL	PENSION AND POST EMPLOYMENT BENEFITS LIABILITY TOTAL	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	December, 2002			22,615			(4,649)	17,966	
2	January	(832)	2,635	24,418	(373)	126	(4,896)	19,522	I
3	February	(832)	2,635	26,221	(373)	132	(5,137)	21,084	I
4	March	(832)	2,635	28,024	(373)	93	(5,417)	22,607	I
5	April	(832)	2,635	29,827	(373)	85	(5,705)	24,122	I
6	May	(832)	2,635	31,630	(373)	106	(5,972)	25,658	I
7	June	(832)	2,635	33,433	(373)	111	(6,234)	27,199	I
8	July	(832)	2,635	35,236	(373)	116	(6,491)	28,745	I
9	August	(832)	2,635	37,039	(373)	166	(6,698)	30,341	I
10	September	(832)	2,635	38,842	(373)	102	(6,969)	31,873	I
11	October	(832)	2,635	40,645	(373)	116	(7,226)	33,419	I
12	November	(832)	2,635	42,448	(373)	110	(7,489)	34,959	I
13	December	(835)	2,635	44,248	(377)	125	(7,741)	36,507	I
14	Average in The Year			33,433			(6,202)	27,231	I
15	Non-Funded Pension Expense and Post Employment Benefit Expense	(9,987)	31,620		(4,480)	1,388			I

I Updated to reflect 2003 actual amounts.

CALCULATION OF AVERAGE OPERATING AND DEBT SERVICE DEFERRAL BALANCES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	2002 DEFERRALS
	(a)	(b)
1	December, 2002	(58,272)
2	January	(53,416)
3	February	(48,560)
4	March	(43,704)
5	April	(38,848)
6	May	(33,992)
7	June	(29,136)
8	July	(24,280)
9	August	(19,424)
10	September	(14,568)
11	October	(9,712)
12	November	(4,856)
13	December	0
14	Average in The Year	(29,136)

l No change from 2003 forecast.

AVERAGE RATE BASE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	TOLLS AMOUNT		SCH. REF.
	(a)	(b)		(c)
	Utility Investment			
1	Gross Plant	12,389,333	I	5.3.1
2	Accumulated Depreciation	(4,308,622)	I	5.3.2
3	Net Plant	8,080,711	I	
4	Contributions in Aid of Construction	(23,288)	I	5.3.3
5	Total Plant	8,057,423	I	
	Working Capital			
6	Cash	20,970	I	5.3.4
7	Goods & Services Tax, Net	(4,531)	I	5.3.4
8	Materials and Supplies	28,932	I	5.3.5
9	Transmission Linepack	42,834		5.3.6
10	Storage Gas	15,617		5.3.6
11	Prepayments and Deposits	2,076	I	5.3.7
12	Total Working Capital	105,898	I	
	Deferred Costs			
13	Miscellaneous Deferred Items	28,475		5.3.8
14	Operating and Debt Service Deferrals	(30,439)	I	5.3.8
15	Surplus Pension/Post Employment Benefits	41,325	I	5.3.8
16	Total Deferred Costs	39,361	I	
17	Total Rate Base	8,202,682	I	
18	Return @ 9.51%	780,075	I	

I Updated to reflect impact of 2003 actuals on 2004 opening balances, adjustments to 2004 OM&A, pension funding, and associated working capital adjustments.

PROJECTED UTILITY INVESTMENT
GAS PLANT IN SERVICE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	JAN 01	JAN 31	FEB 28	MARCH 31	APRIL 30	MAY 31	JUNE 30	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Intangible Plant	8,567	8,567	8,567	8,567	8,567	8,567	8,567	
	Transmission Plant								
2	Land	7,970	7,970	7,970	7,970	7,970	7,970	7,970	I
3	Land Rights	33,159	33,159	33,159	33,159	33,159	33,159	33,159	I
4	Mains	8,708,037	8,711,283	8,714,602	8,718,134	8,718,220	8,719,514	8,720,033	I
5	Compressor	3,289,025	3,290,419	3,292,164	3,294,124	3,295,597	3,296,705	3,298,038	I
6	Measuring and Regulating	109,996	110,003	110,015	110,031	110,052	110,076	110,096	I
7	Communication Equipment - Transmission	13,963	13,989	14,016	14,052	14,097	14,148	14,196	I
	General Plant								
8	Structures and Improvements	12,628	12,628	12,628	12,653	12,680	12,709	12,711	I
	Furniture and Equipment								
9	General	6,194	6,194	6,194	6,194	6,194	6,194	6,194	
10	Computers	102,504	103,130	103,756	104,382	105,008	105,635	106,261	I
	Transportation Equipment								
11	Vehicles	9,335	9,335	9,335	9,335	9,335	9,335	9,335	I
12	Patrol Aircraft	870	870	870	870	870	870	870	
13	Heavy Work Equipment	22,949	22,949	22,949	22,949	22,949	22,949	22,949	I
14	Tools and Work Equipment	27,692	27,692	27,728	27,776	27,938	27,980	28,059	I
15	Communication Equipment - General	8,093	8,093	8,093	8,093	8,093	8,093	8,093	I
16	Total Gas Plant In Service	12,360,982	12,366,282	12,372,046	12,378,289	12,380,730	12,383,905	12,386,532	I
17	AFUDC and Overhead	0	274	572	897	992	1,087	1,200	I
18	Construction Warehouse	2,638	2,638	2,638	2,638	2,638	2,638	2,638	I
19	Net Gas Plant In Service	12,363,620	12,369,194	12,375,257	12,381,825	12,384,361	12,387,631	12,390,370	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

PROJECTED UTILITY INVESTMENT
GAS PLANT IN SERVICE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	JULY 31	AUG 31	SEPT 30	OCT 31	NOV 30	DEC 31	AVERAGE	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Intangible Plant	8,567	8,567	8,567	8,567	8,567	8,567	8,567	
	Transmission Plant								
2	Land	7,970	7,970	7,970	7,970	7,970	7,970	7,970	I
3	Land Rights	33,159	33,159	33,159	33,159	33,159	33,159	33,159	I
4	Mains	8,720,679	8,722,830	8,724,787	8,726,664	8,729,957	8,733,741	8,720,652	I
5	Compressor	3,299,333	3,300,671	3,302,075	3,303,425	3,304,837	3,306,253	3,297,897	I
6	Measuring and Regulating	110,116	110,134	110,158	110,185	110,211	110,232	110,100	I
7	Communication Equipment - Transmission	14,237	14,277	14,323	14,369	14,425	14,477	14,198	I
	General Plant								
8	Structures and Improvements	12,732	12,756	12,781	12,836	12,891	12,945	12,737	I
	Furniture and Equipment								
9	General	6,194	6,194	6,194	6,194	6,194	5,734	6,158	I
10	Computers	106,887	107,513	108,139	108,765	109,392	84,062	104,264	I
	Transportation Equipment								
11	Vehicles	9,335	9,335	9,335	11,635	11,635	11,635	9,866	I
12	Patrol Aircraft	870	870	870	870	870	870	870	
13	Heavy Work Equipment	22,949	22,949	22,949	22,949	22,949	22,949	22,949	I
14	Tools and Work Equipment	28,135	28,308	28,364	28,373	28,376	28,136	28,043	I
15	Communication Equipment - General	8,093	8,093	8,093	8,093	8,093	8,093	8,093	I
16	Total Gas Plant In Service	12,389,256	12,393,627	12,397,763	12,404,055	12,409,525	12,388,823	12,385,524	I
17	AFUDC and Overhead	1,317	1,450	1,601	1,744	1,924	2,158	1,171	I
18	Construction Warehouse	2,638	2,638	2,638	2,638	2,638	2,638	2,638	I
19	Net Gas Plant In Service	12,393,212	12,397,715	12,402,002	12,408,437	12,414,088	12,393,619	12,389,333	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT							
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total
Balance as at								
Dec. 31, 2001	8,567	7,838	33,220	8,679,463	3,399,455	108,284	13,409	12,250,237
Additions	0	0	0	9,561	5,422	84	0	15,066
Retirements	0	0	0	0	(49,951)	0	0	(49,951)
Jan. 31, 2002	8,567	7,838	33,220	8,689,024	3,354,926	108,368	13,409	12,215,352
Additions	0	0	0	284	791	34	0	1,108
Retirements	0	(165)	0	0	(3,644)	0	0	(3,809)
February 28	8,567	7,673	33,220	8,689,308	3,352,073	108,402	13,409	12,212,652
Additions	0	0	0	23	2,271	38	0	2,332
Retirements	0	0	0	(35)	(811)	0	0	(847)
March 31	8,567	7,673	33,220	8,689,295	3,353,533	108,440	13,409	12,214,137
Additions	0	0	0	13	708	6	0	727
Retirements	0	0	0	(755)	(11,293)	0	0	(12,047)
April 30	8,567	7,673	33,220	8,688,553	3,342,948	108,446	13,409	12,202,817
Additions	0	0	0	62	1,934	1,115	0	3,112
Retirements	0	0	(59)	(283)	(1,499)	0	0	(1,841)
					0	(6)	6	0
May 31	8,567	7,673	33,161	8,688,333	3,343,383	109,556	13,414	12,204,087
Additions	0	0	0	0	1,089	134	0	1,224
Retirements	0	0	0	0	(337)	0	0	(337)
June 30, 2002	8,567	7,673	33,161	8,688,333	3,344,135	109,691	13,414	12,204,974
Additions	0	0	0	66	393	139	0	599
Retirements	0	0	0	0	(11,053)	0	0	(11,053)

No change from 2003 Forecast.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT							
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total
July 31, 2002	8,567	7,673	33,161	8,688,399	3,333,475	109,830	13,414	12,194,520
Additions	0	0	0	1,119	1,500	38	0	2,657
Retirements	0	0	(3)	0	(8,050)	(10)	0	(8,064)
August 31	8,567	7,673	33,158	8,689,519	3,326,925	109,858	13,414	12,189,114
Additions	0	0	0	86	1,358	143	0	1,588
Retirements	0	0	0	0	(2,714)	(19)	0	(2,733)
September 30	8,567	7,673	33,158	8,689,605	3,325,569	109,982	13,414	12,187,969
Additions	0	0	0	3,656	3,258	146	0	7,059
Retirements	0	0	0	(1)	(173)	0	0	(174)
October 31	8,567	7,673	33,158	8,693,260	3,328,654	110,127	13,414	12,194,854
Additions	0	0	0	147	4,183	23	0	4,352
Retirements	0	0	0	0	(51,863)	0	0	(51,863)
November 30	8,567	7,673	33,158	8,693,406	3,280,974	110,150	13,414	12,147,343
Additions	0	0	0	416	4,987	526	0	5,929
Retirements	0	0	0	(24)	(4,632)	(41)	0	(4,697)
Dec. 31, 2002	8,567	7,673	33,158	8,693,798	3,281,328	110,636	13,414	12,148,575
Additions	0	0	0	7,568	2,147	22	56	9,794
Retirements	0	0	0	0	(28)	0	0	(28)

No change from 2003 Forecast.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

TRANSMISSION PLANT

	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
Jan. 31, 2003	8,567	7,673	33,158	8,701,366	3,283,447	110,658	13,471	12,158,341	
Additions	0	0	0	336	404	3	0	744	
Retirements	0	0	0	(339)	(449)	0	0	(788)	
February 28	8,567	7,673	33,158	8,701,363	3,283,403	110,661	13,471	12,158,297	
Additions	0	0	0	69	281	15	0	364	
Retirements	0	0	0	(103)	(10)	0	0	(113)	
March 31	8,567	7,673	33,158	8,701,329	3,283,674	110,676	13,471	12,158,549	
Additions	0	0	0	1,559	1,772	(24)	0	3,306	
Retirements	0	0	0	(23)	(3,529)	0	0	(3,553)	
April 30	8,567	7,673	33,158	8,702,864	3,281,917	110,652	13,471	12,158,302	
Additions	0	263	0	58	51	4	0	376	
Retirements	0	0	0	0	(89)	0	0	(89)	
May 31	8,567	7,937	33,158	8,702,922	3,281,879	110,656	13,471	12,158,589	
Additions	0	0	0	1,142	287	93	0	1,523	
Retirements	0	0	0	0	(803)	0	0	(803)	
June 30, 2003	8,567	7,937	33,158	8,704,064	3,281,363	110,749	13,471	12,159,309	
Additions	0	0	0	388	2,889	0	139	3,416	I
Retirements	0	0	0	(7)	(110)	0	0	(117)	I

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT								
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
July 31, 2003	8,567	7,937	33,159	8,704,446	3,284,142	110,750	13,609	12,162,609	I
Additions	0	0	0	432	197	(1)	3	632	I
Retirements	0	0	0	(89)	(215)	(39)	0	(342)	I
August 31	8,567	7,937	33,159	8,704,789	3,284,124	110,710	13,612	12,162,898	I
Additions	0	0	0	1,074	1,821	0	0	2,895	I
Retirements	0	0	0	(88)	(677)	(453)	0	(1,218)	I
September 30	8,567	7,937	33,159	8,705,775	3,285,268	110,257	13,612	12,164,575	I
Additions	0	0	0	97	1,210	0	0	1,307	I
Retirements	0	0	0	0	(137)	0	0	(137)	I
October 31	8,567	7,937	33,159	8,705,872	3,286,341	110,257	13,612	12,165,744	I
Additions	0	34	0	2,331	915	0	0	3,280	I
Retirements	0	0	0	(435)	(304)	(261)	0	(1,000)	I
November 30	8,567	7,970	33,159	8,707,769	3,286,952	109,996	13,612	12,168,024	I
Additions	0	0	0	300	2,322	0	351	2,973	I
Retirements	0	0	0	(31)	(249)	0	0	(280)	I
Dec 31, 2003	8,567	7,970	33,159	8,708,037	3,289,025	109,996	13,963	12,170,717	I
Additions	0	0	0	3,246	1,394	7	27	4,674	I
Retirements	0	0	0	0	0	0	0	0	

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

TRANSMISSION PLANT

	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
Jan. 31, 2004	8,567	7,970	33,159	8,711,283	3,290,419	110,003	13,989	12,175,390	I
Additions	0	0	0	3,319	1,745	12	27	5,103	I
Retirements	0	0	0	0	0	0	0	0	
February 28	8,567	7,970	33,159	8,714,602	3,292,164	110,015	14,016	12,180,493	I
Additions	0	0	0	3,532	1,960	16	36	5,544	I
Retirements	0	0	0	0	0	0	0	0	
March 31	8,567	7,970	33,159	8,718,134	3,294,124	110,031	14,052	12,186,037	I
Additions	0	0	0	86	1,473	21	45	1,626	
Retirements	0	0	0	0	0	0	0	0	
April 30	8,567	7,970	33,159	8,718,220	3,295,597	110,052	14,097	12,187,663	I
Additions	0	0	0	1,295	1,108	24	51	2,477	
Retirements	0	0	0	0	0	0	0	0	
May 31	8,567	7,970	33,159	8,719,514	3,296,705	110,076	14,148	12,190,140	I
Additions	0	0	0	519	1,333	21	48	1,921	
Retirements	0	0	0	0	0	0	0	0	
June 30, 2004	8,567	7,970	33,159	8,720,033	3,298,038	110,096	14,196	12,192,060	I
Additions	0	0	0	646	1,295	19	41	2,001	
Retirements	0	0	0	0	0	0	0	0	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

TRANSMISSION PLANT

	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
July 31, 2004	8,567	7,970	33,159	8,720,679	3,299,333	110,116	14,237	12,194,062	I
Additions	0	0	0	2,150	1,338	19	39	3,547	
Retirements	0	0	0	0	0	0	0	0	
August 31	8,567	7,970	33,159	8,722,830	3,300,671	110,134	14,277	12,197,608	I
Additions	0	0	0	1,957	1,403	23	46	3,430	
Retirements	0	0	0	0	0	0	0	0	
September 30	8,567	7,970	33,159	8,724,787	3,302,075	110,158	14,323	12,201,038	I
Additions	0	0	0	1,877	1,350	28	46	3,301	
Retirements	0	0	0	0	0	0	0	0	
October 31	8,567	7,970	33,159	8,726,664	3,303,425	110,185	14,369	12,204,340	I
Additions	0	0	0	3,293	1,412	26	56	4,786	
Retirements	0	0	0	0	0	0	0	0	
Nov 30, 2004	8,567	7,970	33,159	8,729,957	3,304,837	110,211	14,425	12,209,126	I
Additions	0	0	0	3,784	1,416	21	51	5,272	
Retirements	0	0	0	0	0	0	0	0	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

TRANSMISSION PLANT

	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
Dec. 31, 2004	8,567	7,970	33,159	8,733,741	3,306,253	110,232	14,477	12,214,398	I
Balance as at Dec. 31, 2001	8,567	7,838	33,220	8,679,463	3,399,455	108,284	13,409	12,250,237	
Additions	0	297	0	56,491	59,419	2,776	1,062	120,046	I
Retirements	0	(165)	(62)	(2,214)	(152,621)	(823)	0	(155,885)	I
Transfers	0	0	0	0	0	(6)	6	0	
Dec.31, 2004	8,567	7,970	33,159	8,733,741	3,306,253	110,232	14,477	12,214,398	I

Transmission Plant Additions	2002	45,753	
	2003	30,610	I
	2004	43,682	I
Transmission Plant Retirements	2002	(147,416)	
	2003	(8,469)	I
	2004	0	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

GENERAL PLANT

	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work		
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total
Balance as at									
Dec. 31, 2001	22,053	7,729	133,351	8,627	870	22,730	28,226	7,698	231,285
Additions	0	0	60	0	0	0	14	(2)	72
Retirements	0	(2)	0	0	0	0	0	0	(2)
Jan. 31, 2002	22,053	7,727	133,410	8,627	870	22,730	28,240	7,696	231,355
Additions	0	0	1,321	0	0	3	6	50	1,380
Retirements	0	0	0	0	0	0	0	0	0
February 28	22,053	7,727	134,731	8,627	870	22,733	28,246	7,746	232,735
Additions	0	0	1,719	(413)	0	3	(7)	(14)	1,287
Retirements	0	0	0	0	0	0	0	0	0
March 31	22,053	7,727	136,450	8,214	870	22,736	28,239	7,733	234,022
Additions	0	(1)	1,818	548	0	1	1	14	2,379
Retirements	(9,134)	0	0	(122)	0	0	0	0	(9,257)
April 30	12,919	7,726	138,268	8,639	870	22,736	28,240	7,746	227,144
Additions	0	0	(232)	39	0	0	39	(1)	(154)
Retirements	0	0	0	0	0	0	0	0	0
May 31	12,919	7,726	138,036	8,679	870	22,736	28,279	7,745	226,990
Additions	0	0	1,217	(12)	0	0	33	8	1,245
Retirements	0	0	0	0	0	0	0	0	0
June 30, 2002	12,919	7,726	139,253	8,667	870	22,736	28,312	7,753	228,236
Additions	0	0	1,513	63	0	0	1	41	1,618
Retirements	0	(2)	1	(1)	0	0	1	0	(1)
Transfer				22			(22)		0

No change from 2003 Forecast.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT								
	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work		
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total
July 31, 2002	12,919	7,724	140,767	8,751	870	22,736	28,291	7,795	229,853
Additions	23	0	1,066	31	0	0	68	9	1,197
Retirements	0	0	0	0	0	0	0	0	0
August 31	12,942	7,724	141,832	8,782	870	22,736	28,359	7,804	231,050
Additions	0	0	745	0	0	12	54	(18)	794
Retirements	0	0	0	0	0	0	0	0	0
September 30	12,942	7,724	142,578	8,782	870	22,748	28,414	7,786	231,844
Additions	12	0	1,828	0	0	0	47	(2)	1,886
Retirements	0	0	(21,765)	(426)	0	0	0	0	(22,191)
October 31	12,954	7,724	122,641	8,356	870	22,748	28,460	7,784	211,538
Additions	4	0	1,057	1,142	0	0	17	11	2,232
Retirements	0	0	0	0	0	0	0	0	0
November 30	12,958	7,724	123,698	9,498	870	22,748	28,477	7,796	213,770
Additions	0	6	1,976	412	0	1	146	43	2,584
Retirements	(349)	(38)	0	0	0	0	(27)	0	(413)
Dec. 31, 2002	12,609	7,693	125,675	9,910	870	22,749	28,596	7,839	215,941
Additions	0	0	540	(1,709)	0	0	19	0	(1,150)
Retirements	0	0	0	0	0	0	0	0	0

No change from 2003 Forecast.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT								
	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work		
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total
Jan. 31, 2003	12,609	7,693	126,215	8,201	870	22,750	28,615	7,839	214,791
Additions	0	0	492	0	0	9	0	0	501
Retirements	0	0	0	0	0	0	0	0	0
February 28	12,609	7,693	126,707	8,201	870	22,759	28,615	7,839	215,293
Additions	0	0	583	48	0	0	0	0	631
Retirements	0	0	0	0	0	0	0	0	0
March 31	12,609	7,693	127,290	8,249	870	22,759	28,615	7,839	215,924
Additions	0	(1)	520	65	0	2	0	0	586
Retirements	0	0	0	0	0	0	0	0	0
April 30	12,609	7,692	127,810	8,314	870	22,761	28,615	7,839	216,510
Additions	0	0	379	1	0	26	(19)	(1)	385
Retirements	0	0	0	0	0	(16)	(13)	0	(29)
May 31	12,609	7,692	128,188	8,315	870	22,770	28,583	7,838	216,866
Additions	2	0	377	0	0	6	13	0	397
Retirements	0	0	0	0	0	0	0	0	0
June 30, 2003	12,611	7,692	128,566	8,315	870	22,776	28,596	7,838	217,263
Additions	0	0	38	0	0	14	2	0	54 I
Retirements	0	0	0	0	0	0	0	0	0

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT									
	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work			
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total	
July 31, 2003	12,611	7,692	128,604	8,315	870	22,790	28,598	7,838	217,317	I
Additions	15	0	153	0	0	1	0	255	424	I
Retirements	0	0	0	0	0	0	0	0	0	
August 31	12,626	7,692	128,757	8,315	870	22,791	28,598	8,093	217,741	I
Additions	2	0	357	0	0	5	26	0	389	I
Retirements	0	0	0	0	0	0	0	0	0	
September 30	12,628	7,692	129,114	8,315	870	22,795	28,624	8,093	218,130	I
Additions	(1)	0	208	263	0	75	(46)	0	499	I
Retirements	0	0	0	0	0	0	0	0	0	
October 31	12,627	7,692	129,322	8,578	870	22,870	28,578	8,093	218,629	I
Additions	0	0	447	435	0	10	125	0	1,018	I
Retirements	0	0	0	0	0	0	0	0	0	
November 30	12,627	7,692	129,769	9,013	870	22,880	28,703	8,093	219,647	I
Additions	1	0	322	551	0	69	24	0	968	I
Retirements	0	(1,498)	(27,587)	(229)	0	0	(1,035)	0	(30,349)	I
Dec. 31, 2003	12,628	6,194	102,504	9,335	870	22,949	27,692	8,093	190,265	I
Additions	0	0	626	0	0	0	0	0	626	
Retirements	0	0	0	0	0	0	0	0	0	

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT									
	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work			
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total	
Jan. 31, 2004	12,628	6,194	103,130	9,335	870	22,949	27,692	8,093	190,891	I
Additions	0	0	626	0	0	0	36	0	662	
Retirements	0	0	0	0	0	0	0	0	0	
February 28	12,628	6,194	103,756	9,335	870	22,949	27,728	8,093	191,553	I
Additions	25	0	626	0	0	0	48	0	699	
Retirements	0	0	0	0	0	0	0	0	0	
March 31	12,653	6,194	104,382	9,335	870	22,949	27,776	8,093	192,252	I
Additions	27	0	626	0	0	0	162	0	815	
Retirements	0	0	0	0	0	0	0	0	0	
April 30	12,680	6,194	105,008	9,335	870	22,949	27,938	8,093	193,068	I
Additions	29	0	626	0	0	0	42	0	698	
Retirements	0	0	0	0	0	0	0	0	0	
May 31	12,709	6,194	105,635	9,335	870	22,949	27,980	8,093	193,765	I
Additions	2	0	626	0	0	0	78	0	707	
Retirements	0	0	0	0	0	0	0	0	0	
June 30, 2004	12,711	6,194	106,261	9,335	870	22,949	28,059	8,093	194,472	I
Additions	20	0	626	0	0	0	76	0	723	
Retirements	0	0	0	0	0	0	0	0	0	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT									
	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work			
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total	
July 31, 2004	12,732	6,194	106,887	9,335	870	22,949	28,135	8,093	195,195	I
Additions	24	0	626	0	0	0	173	0	824	
Retirements	0	0	0	0	0	0	0	0	0	
August 31	12,756	6,194	107,513	9,335	870	22,949	28,308	8,093	196,018	I
Additions	24	0	626	0	0	0	56	0	707	
Retirements	0	0	0	0	0	0	0	0	0	
September 30	12,781	6,194	108,139	9,335	870	22,949	28,364	8,093	196,725	I
Additions	55	0	626	2,300	0	0	9	0	2,990	
Retirements	0	0	0	0	0	0	0	0	0	
October 31	12,836	6,194	108,765	11,635	870	22,949	28,373	8,093	199,715	I
Additions	55	0	626	0	0	0	3	0	684	
Retirements	0	0	0	0	0	0	0	0	0	
Nov. 30, 2004	12,891	6,194	109,392	11,635	870	22,949	28,376	8,093	200,399	I
Additions	55	0	626	0	0	0	0	0	681	
Retirements	0	(460)	(25,956)	0	0	0	(240)	0	(26,656)	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CALCULATION OF MONTH - END GROSS PLANT BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT									
	Structures, Office Furniture and Equipment			Transportation Equipment		Heavy Work	Tools & Work			
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total	
Dec 31, 2004	12,945	5,734	84,062	11,635	870	22,949	28,136	8,093	174,424	I
Balance as at Dec. 31, 2001	22,053	7,729	133,351	8,627	870	22,730	28,226	7,698	231,285	
Additions	376	4	26,018	3,765	0	235	1,245	395	32,037	I
Retirements	(9,483)	(2,000)	(75,306)	(779)	0	(16)	(1,314)	0	(88,898)	I
Transfers	0	0	0	22	0	0	(22)	0	0	
Dec.31, 2004	12,945	5,734	84,062	11,635	870	22,949	28,136	8,093	174,424	I

General Plant Additions	2002	16,520	
	2003	4,702	I
	2004	10,815	

General Plant Retirements	2002	(31,864)	
	2003	(30,378)	I
	2004	(26,656)	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

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ANALYSIS OF GPUC
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	DIRECT COSTS INCURRED	DIRECT COSTS TRANSFERS TO GPIS	AFUDC BASE	AFUDC CAPITALIZED	OVERHEAD CAPITALIZED	TRANSFERS TO G.P.I.S. AFUDC	TRANSFERS TO G.P.I.S. OVERHEAD	OTHER TRANSFERS	PROJECTED G.P.U.C. BALANCE	13 MONTH AVERAGE	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	December 2003									11,828		I
2	January 2004	1,254	(4,674)	10,025	80	48	(40)	(234)	0	8,262		I
3	February	1,647	(5,103)	6,443	52	72	(44)	(255)	0	4,631		I
4	March	1,917	(5,544)	2,727	22	96	(47)	(277)	0	798		I
5	April	2,097	(1,626)	1,045	9	105	(14)	(81)	0	1,288		I
6	May	2,240	(2,477)	1,188	10	112	(21)	(74)	0	1,077		I
7	June	2,418	(1,921)	1,350	11	146	(16)	(96)	0	1,619		I
8	July	2,874	(2,001)	2,077	17	144	(17)	(100)	0	2,535		I
9	August	3,730	(3,547)	2,629	21	106	(30)	(102)	0	2,714		I
10	September	5,303	(3,430)	3,647	29	115	(29)	(121)	0	4,580		I
11	October	4,414	(3,301)	5,154	41	151	(28)	(115)	0	5,741		I
12	November	3,148	(4,786)	4,931	40	157	(41)	(139)	0	4,119		I
13	December	1,930	(5,272)	2,415	20	122	(45)	(189)	0	685		I
14	Total 2004	32,972	(43,682)		351	1,374	(374)	(1,784)	0		3,837	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

PROJECTED UTILITY INVESTMENT
ACCUMULATED DEPRECIATION AND AMORTIZATION
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	JAN 01	JAN 31	FEB 28	MARCH 31	APRIL 30	MAY 31	JUNE 30	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Intangible Plant	6,164	6,181	6,198	6,216	6,233	6,251	6,268	I
	Transmission Plant								
2	Land	0	0	0	0	0	0	0	
3	Land Rights	11,930	12,005	12,081	12,156	12,231	12,307	12,382	
4	Mains	3,179,158	3,199,622	3,220,094	3,240,573	3,261,061	3,281,549	3,302,039	I
5	Compressor	831,841	840,828	849,792	858,657	867,583	876,438	885,167	I
6	Measuring and Regulating	38,023	38,373	38,723	39,074	39,424	39,774	40,125	I
7	Communication Equipment - Transmission	9,617	9,684	9,750	9,817	9,884	9,950	10,018	I
	General Plant								
8	Structures and Improvements	2,876	2,929	2,981	3,033	3,068	3,103	3,138	I
	Furniture and Equipment								
9	General	(3,646)	(3,588)	(3,529)	(3,470)	(3,411)	(3,352)	(3,294)	I
10	Computers	38,859	41,128	43,412	45,709	48,020	50,345	52,684	I
	Transportation Equipment								
11	Vehicles	1,559	1,649	1,739	1,828	1,918	2,007	2,097	I
12	Patrol Aircraft	1,580	1,580	1,580	1,580	1,580	1,580	1,580	
13	Heavy Work Equipment	9,568	9,603	9,639	9,675	9,711	9,746	9,782	I
14	Tools and Work Equipment	10,790	10,874	10,958	11,043	11,127	11,212	11,297	I
15	Communication Equipment - General	4,530	4,552	4,574	4,596	4,618	4,640	4,662	I
16	Total Accumulated Depreciation	4,142,848	4,175,421	4,207,992	4,240,486	4,273,046	4,305,550	4,337,946	I
17	AFUDC and Overhead	0	0	1	2	5	7	10	I
18	Net Accumulated Depreciation	4,142,848	4,175,421	4,207,992	4,240,488	4,273,051	4,305,557	4,337,956	I
19	Retirement Work In Progress	(27,812)	(27,812)	(27,812)	(27,812)	(27,812)	(27,812)	(27,812)	I
20	Accumulated Depreciation	4,115,036	4,147,609	4,180,180	4,212,676	4,245,239	4,277,745	4,310,144	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

PROJECTED UTILITY INVESTMENT
ACCUMULATED DEPRECIATION AND AMORTIZATION
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	JULY 31	AUG 31	SEPT 30	OCT 31	NOV 30	DEC 31	AVERAGE	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Intangible Plant	6,285	6,303	6,320	6,338	6,355	6,373	6,268	
	Transmission Plant								
2	Land	0	0	0	0	0	0	0	
3	Land Rights	12,458	12,533	12,609	12,684	12,759	12,835	12,382	
4	Mains	3,322,531	3,343,025	3,363,524	3,384,027	3,404,535	3,425,050	3,302,061	I
5	Compressor	893,926	902,829	912,141	921,458	930,780	940,106	885,504	I
6	Measuring and Regulating	40,475	40,826	41,176	41,527	41,878	42,229	40,125	I
7	Communication Equipment - Transmission	10,085	10,153	10,221	10,289	10,357	10,425	10,019	I
	General Plant								
8	Structures and Improvements	3,191	3,244	3,293	3,343	3,393	3,441	3,156	I
	Furniture and Equipment								
9	General	(3,235)	(3,176)	(3,117)	(3,059)	(3,000)	(3,401)	(3,329)	I
10	Computers	55,037	57,404	59,784	62,179	64,587	41,053	50,785	I
	Transportation Equipment								
11	Vehicles	2,187	2,276	2,423	2,570	2,740	2,909	2,146	I
12	Patrol Aircraft	1,580	1,580	1,580	1,580	1,580	1,580	1,580	
13	Heavy Work Equipment	9,818	9,854	9,889	9,925	9,961	9,997	9,782	I
14	Tools and Work Equipment	11,382	11,468	11,554	11,640	11,727	11,573	11,280	I
15	Communication Equipment - General	4,684	4,706	4,728	4,750	4,772	4,794	4,662	I
16	Total Accumulated Depreciation	4,370,405	4,403,024	4,436,126	4,469,252	4,502,424	4,508,964	4,336,422	I
17	AFUDC and Overhead	13	17	20	25	29	34	13	I
18	Net Accumulated Depreciation	4,370,419	4,403,041	4,436,147	4,469,277	4,502,453	4,508,998	4,336,434	I
19	Retirement Work In Progress	(27,812)	(27,812)	(27,812)	(27,812)	(27,812)	(27,812)	(27,812)	I
20	Accumulated Depreciation	4,342,607	4,375,229	4,408,335	4,441,465	4,474,641	4,481,186	4,308,622	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

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CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT							
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total
Balance as at Dec. 31, 2001	5,745	0	10,332	2,710,183	744,874	30,602	7,782	3,509,518
Depreciation	17	0	58	18,824	9,354	334	92	28,679
Retirements	0	0	0	0	(49,951)	0	0	(49,951)
Transfer								
Jan. 31, 2002	5,763	0	10,390	2,729,007	704,277	30,936	7,874	3,488,246
Depreciation	17	0	58	18,824	9,273	334	92	28,599
Retirements	0	0	0	0	(3,774)	0	0	(3,774)
February 28	5,780	0	10,448	2,747,831	709,777	31,270	7,966	3,513,071
Depreciation	17	0	58	18,825	9,266	334	92	28,592
Retirements	0	0	0	(36)	(819)	(4)	0	(859)
March 31	5,798	0	10,507	2,766,619	718,223	31,600	8,058	3,540,804
Depreciation	17	0	58	18,824	9,280	334	85	28,599
Retirements	0	0	0	(777)	(11,293)	0	0	(12,069)
April 30	5,815	0	10,565	2,784,667	716,210	31,934	8,143	3,557,334
Depreciation	17	0	58	18,823	9,244	334	92	28,570
Retirements	0	0	(5)	(283)	(1,565)	0	0	(1,852)
May 31	5,833	0	10,619	2,803,208	723,890	32,268	8,235	3,584,052
Depreciation	17	0	58	18,823	9,246	337	92	28,574
Retirements	0	0	0	0	(359)	0	0	(359)
June 30, 2002	5,850	0	10,677	2,822,031	732,777	32,605	8,327	3,612,267
Depreciation	17	0	58	18,823	9,249	338	92	28,577
Retirements	0	0	0	(12)	(11,160)	0	0	(11,172)

No change from 2003 Forecast.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT							
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total
July 31, 2002	5,867	0	10,736	2,840,842	730,866	32,943	8,419	3,629,672
Depreciation	17	0	58	18,823	9,218	338	92	28,547
Retirements	0	0	(3)	(11)	(8,056)	(10)	0	(8,081)
August 31	5,885	0	10,791	2,859,653	732,028	33,271	8,511	3,650,139
Depreciation	17	0	58	18,826	9,247	338	59	28,545
Retirements	0	0	0	0	(2,724)	(34)	0	(2,758)
September 30	5,902	0	10,849	2,878,479	738,551	33,575	8,570	3,675,926
Depreciation	17	0	58	18,826	9,198	339	92	28,530
Retirements	0	0	0	(31)	(173)	0	0	(204)
October 31	5,920	0	10,908	2,897,274	747,576	33,914	8,662	3,704,253
Depreciation	17	0	58	18,834	9,204	339	92	28,545
Retirements	0	0	0	0	(51,958)	0	0	(51,958)
November 30	5,937	0	10,966	2,916,107	704,822	34,253	8,754	3,680,839
Depreciation	17	0	58	18,834	9,074	339	92	28,415
Retirements	0	0	0	(24)	(4,700)	(41)	0	(4,765)
Dec. 31, 2002	5,954	0	11,024	2,934,917	709,195	34,551	8,847	3,704,489
Depreciation	17	0	76	20,451	10,917	354	64	31,878
Retirements	0	0	0	0	(452)	0	0	(452)

No change from 2003 Forecast.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT								
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
Jan. 31, 2003	5,972	0	11,100	2,955,368	719,660	34,905	8,910	3,735,915	
Depreciation	17	0	75	20,448	10,924	352	64	31,880	
Retirements	0	0	0	(339)	(449)	0	0	(788)	
February 28	5,989	0	11,175	2,975,476	730,135	35,257	8,974	3,767,008	
Depreciation	17	0	75	20,448	10,923	352	64	31,881	
Retirements	0	0	0	(103)	(663)	0	0	(766)	
March 31	6,007	0	11,251	2,995,822	740,395	35,609	9,038	3,798,122	
Depreciation	17	0	75	20,448	10,924	352	64	31,881	
Retirements	0	0	0	(36)	(3,856)	0	0	(3,892)	
April 30	6,024	0	11,326	3,016,234	747,463	35,962	9,102	3,826,111	
Depreciation	17	0	75	20,452	10,919	352	64	31,879	
Retirements	0	0	0	0	(89)	0	0	(89)	
May 31	6,042	0	11,402	3,036,686	758,293	36,314	9,166	3,857,902	
Depreciation	17	0	75	20,452	10,918	352	64	31,879	
Retirements	0	0	0	0	(803)	0	0	(803)	
June 30, 2003	6,059	0	11,477	3,057,138	768,409	36,666	9,230	3,888,979	
Depreciation	17	0	75	20,455	10,916	353	64	31,880	I
Retirements	0	0	0	(43)	(110)	0	0	(153)	I

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT								
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
July 31, 2003	6,076	0	11,553	3,077,550	779,214	37,019	9,294	3,920,706	I
Depreciation	17	0	75	20,455	10,925	353	65	31,891	I
Retirements	0	0	0	(89)	(215)	(39)	0	(343)	I
August 31	6,094	0	11,628	3,097,916	789,924	37,333	9,359	3,952,254	I
Depreciation	17	0	75	20,456	10,925	353	65	31,891	I
Retirements	0	0	0	(88)	112	(453)	0	(429)	I
September 30	6,111	0	11,703	3,118,284	800,961	37,232	9,423	3,983,716	I
Depreciation	17	0	75	20,459	10,929	351	65	31,896	I
Retirements	0	0	0	(40)	(1,363)	0	0	(1,403)	I
October 31	6,129	0	11,779	3,138,702	810,528	37,583	9,488	4,014,209	I
Depreciation	17	0	75	20,459	10,932	351	65	31,900	I
Retirements	0	0	0	(435)	(304)	(261)	0	(1,000)	I
November 30	6,146	0	11,854	3,158,726	821,156	37,673	9,553	4,045,109	I
Depreciation	17	0	75	20,463	10,935	350	65	31,906	I
Retirements	0	0	0	(31)	(250)	0	0	(282)	I
December 31, 2003	6,164	0	11,930	3,179,158	831,841	38,023	9,617	4,076,733	I
Depreciation	17	0	75	20,464	10,936	350	66	31,909	I
Retirements	0	0	0	0	(1,948)	0	0	(1,948)	

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT								
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
Jan. 31, 2004	6,181	0	12,005	3,199,622	840,828	38,373	9,684	4,106,694	I
Depreciation	17	0	75	20,472	10,941	350	66	31,922	I
Retirements	0	0	0	0	(1,977)	0	0	(1,977)	
February 28	6,198	0	12,081	3,220,094	849,792	38,723	9,750	4,136,638	I
Depreciation	17	0	75	20,479	10,946	350	67	31,935	I
Retirements	0	0	0	0	(2,082)	0	0	(2,082)	
March 31	6,216	0	12,156	3,240,573	858,657	39,074	9,817	4,166,492	I
Depreciation	17	0	75	20,488	10,953	350	67	31,950	I
Retirements	0	0	0	0	(2,027)	0	0	(2,027)	
April 30	6,233	0	12,231	3,261,061	867,583	39,424	9,884	4,196,415	I
Depreciation	17	0	75	20,488	10,958	350	67	31,956	I
Retirements	0	0	0	0	(2,103)	0	0	(2,103)	
May 31	6,251	0	12,307	3,281,549	876,438	39,774	9,950	4,226,268	I
Depreciation	17	0	75	20,491	10,962	350	67	31,963	I
Retirements	0	0	0	0	(2,232)	0	0	(2,232)	
June 30, 2004	6,268	0	12,382	3,302,039	885,167	40,125	10,018	4,255,999	I
Depreciation	17	0	75	20,492	10,966	350	67	31,969	I
Retirements	0	0	0	0	(2,206)	0	0	(2,206)	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT								
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
July 31, 2004	6,285	0	12,458	3,322,531	893,926	40,475	10,085	4,285,761	I
Depreciation	17	0	75	20,494	10,970	351	68	31,975	I
Retirements	0	0	0	0	(2,067)	0	0	(2,067)	
August 31	6,303	0	12,533	3,343,025	902,829	40,826	10,153	4,315,669	I
Depreciation	17	0	75	20,499	10,975	351	68	31,985	I
Retirements	0	0	0	0	(1,662)	0	0	(1,662)	
September 30	6,320	0	12,609	3,363,524	912,141	41,176	10,221	4,345,991	I
Depreciation	17	0	75	20,503	10,979	351	68	31,994	I
Retirements	0	0	0	0	(1,662)	0	0	(1,662)	
October 31	6,338	0	12,684	3,384,027	921,458	41,527	10,289	4,376,323	I
Depreciation	17	0	75	20,508	10,984	351	68	32,003	I
Retirements	0	0	0	0	(1,662)	0	0	(1,662)	
November 30, 2004	6,355	0	12,759	3,404,535	930,780	41,878	10,357	4,406,664	I
Depreciation	17	0	75	20,515	10,989	351	69	32,016	I
Retirements	0	0	0	0	(1,662)	0	0	(1,662)	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	TRANSMISSION PLANT								
	Intangible Plant	Land	Land Rights	Mains	Compression	Measuring and Regulating	Field Communication	Total	
December 31, 2004	6,373	0	12,835	3,425,050	940,106	42,229	10,425	4,437,018	I
Balance as at Dec. 31, 2001	5,745	0	10,332	2,710,183	744,874	30,602	7,782	3,509,518	
Depreciation	627	0	2,511	717,246	373,499	12,469	2,644	1,108,995	I
Retirements	0	0	(7)	(2,378)	(178,267)	(842)	0	(181,495)	I
Transfers	0	0	0	0	0	0	0	0	
Dec.31, 2004	6,373	0	12,835	3,425,050	940,106	42,229	10,425	4,437,018	I

Transmission Plant Depreciation	2002	342,774	
	2003	382,643	I
	2004	383,578	I
Transmission Plant Retirements	2002	(147,803)	
	2003	(10,399)	I
	2004	(23,293)	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT								
	Structures & Improvements	Office Furniture & Equipment: General	Office Furniture & Equipment: Computers	Transportation Equipment: Autos	Transportation Equipment: Patrol Aircraft	Heavy Work Equipment	Tools & Work Equipment	Communication	Total
Balance as at Dec. 31, 2001	11,096	(3,758)	36,652	1,010	1,580	9,008	10,435	3,591	69,614
Depreciation	52	28	1,440	34	0	7	32	55	1,648
Retirements	(3)	(2)	0	0	0	0	0	0	(5)
Jan. 31, 2002	11,145	(3,732)	38,093	1,044	1,580	9,016	10,467	3,646	71,258
Depreciation	52	28	1,441	34	0	7	32	55	1,649
Retirements	0	0	0	0	0	0	0	0	0
February 28	11,197	(3,704)	39,533	1,078	1,580	9,023	10,499	3,701	72,907
Depreciation	52	28	1,455	34	0	7	32	55	1,663
Retirements	0	411	0	0	0	0	0	0	411
March 31	11,249	(3,266)	40,989	1,113	1,580	9,030	10,531	3,756	74,981
Depreciation	52	28	1,472	33	0	7	32	55	1,679
Retirements	(9,134)	0	0	(122)	0	0	0	0	(9,257)
April 30	2,166	(3,238)	42,460	1,023	1,580	9,038	10,563	3,811	67,403
Depreciation	52	28	1,493	34	0	7	32	55	1,702
Retirements	0	0	0	0	0	0	0	0	0
May 31	2,218	(3,211)	43,954	1,058	1,580	9,045	10,595	3,866	69,105
Depreciation	52	28	1,491	34	0	7	32	55	1,700
Retirements	0	0	0	0	0	0	0	17	17
June 30, 2002	2,270	(3,183)	45,444	1,092	1,580	9,053	10,627	3,938	70,822
Depreciation	52	28	1,504	34	0	7	32	55	1,713
Retirements	0	(2)	1	(1)	0	0	1	0	(1)

No change from 2003 Forecast.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

GENERAL PLANT

	Structures &	Office Furniture & Equipment		Transportation Equipment		Heavy Work	Tools & Work		
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total
July 31, 2002	2,323	(3,157)	46,950	1,126	1,580	9,060	10,660	3,993	72,534
Depreciation	52	28	1,520	35	0	7	32	55	1,730
Retirements	0	0	0	3	0	0	0	0	3
August 31	2,375	(3,129)	48,470	1,163	1,580	9,067	10,692	4,049	74,266
Depreciation	53	28	1,532	35	0	8	31	56	1,742
Retirements	0	0	0	0	0	0	0	0	0
September 30	2,427	(3,102)	50,002	1,198	1,580	9,075	10,724	4,104	76,008
Depreciation	53	28	1,540	35	0	7	32	55	1,750
Retirements	0	0	(21,765)	(426)	0	0	0	0	(22,191)
October 31	2,480	(3,074)	29,777	807	1,580	9,083	10,756	4,160	55,568
Depreciation	53	28	1,325	33	0	7	32	55	1,533
Retirements	(3)	0	0	0	0	0	0	0	(3)
November 30	2,531	(3,046)	31,101	840	1,580	9,090	10,788	4,215	57,098
Depreciation	53	28	1,336	38	0	7	32	55	1,550
Retirements	(349)	(38)	0	0	0	0	(27)	0	(413)
Dec. 31, 2002	2,235	(3,056)	32,437	878	1,580	9,098	10,793	4,270	58,235
Depreciation	(146)	74	2,783	7	0	35	86	22	2,861
Retirements	0	0	0	0	0	0	0	0	0

No change from 2003 Forecast.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

	GENERAL PLANT								
	Structures &	Office Furniture & Equipment		Transportation Equipment		Heavy Work	Tools & Work		
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total
Jan. 31, 2003	2,089	(2,982)	35,220	885	1,580	9,133	10,880	4,292	61,096
Depreciation	53	73	2,793	88	0	35	87	21	3,152
Retirements	204	0	0	0	0	0	0	0	204
February 28	2,346	(2,909)	38,013	973	1,580	9,169	10,967	4,313	64,452
Depreciation	53	73	2,806	88	0	35	87	21	3,164
Retirements	0	0	0	0	0	0	0	0	0
March 31	2,399	(2,836)	40,819	1,062	1,580	9,204	11,054	4,335	67,616
Depreciation	53	73	2,818	79	0	35	87	21	3,167
Retirements	0	0	0	0	0	0	0	0	0
April 30	2,452	(2,763)	43,637	1,141	1,580	9,239	11,141	4,356	70,783
Depreciation	53	73	2,830	80	0	35	87	21	3,180
Retirements	0	0	0	0	0	(16)	(13)	0	(29)
May 31	2,505	(2,690)	46,467	1,221	1,580	9,259	11,215	4,378	73,934
Depreciation	53	73	2,838	80	0	35	87	21	3,188
Retirements	0	0	0	0	0	0	0	0	0
June 30, 2003	2,558	(2,617)	49,305	1,300	1,580	9,294	11,302	4,399	77,122
Depreciation	53	73	2,847	80	0	35	87	21	3,196
Retirements	0	0	0	0	0	60	0	0	60

No change from 2003 Forecast.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

GENERAL PLANT

	Structures & Improvements	Office Furniture & Equipment General	Office Furniture & Equipment Computers	Transportation Equipment Autos	Transportation Equipment Patrol Aircraft	Heavy Work Equipment	Tools & Work Equipment	Communication	Total	
July 31, 2003	2,611	(2,544)	52,152	1,380	1,580	9,390	11,389	4,420	80,378	I
Depreciation	53	73	2,847	80	0	36	87	21	3,197	I
Retirements	0	0	0	0	0	0	0	0	0	
August 31	2,664	(2,471)	54,999	1,460	1,580	9,425	11,476	4,442	83,576	I
Depreciation	53	73	2,851	80	0	36	87	22	3,201	I
Retirements	0	0	0	0	0	0	0	0	0	
September 30	2,717	(2,398)	57,850	1,540	1,580	9,461	11,563	4,464	86,777	I
Depreciation	53	73	2,859	80	0	36	87	22	3,209	I
Retirements	0	0	0	0	0	0	0	0	0	
October 31	2,770	(2,325)	60,709	1,620	1,580	9,496	11,650	4,486	89,986	I
Depreciation	53	73	2,863	82	0	36	87	22	3,216	I
Retirements	0	31	0	0	0	0	0	0	31	I
November 30	2,823	(2,221)	63,573	1,702	1,580	9,532	11,737	4,508	93,233	I
Depreciation	53	73	2,873	87	0	36	87	22	3,231	I
Retirements	0	(1,498)	(27,587)	(229)	0	0	(1,035)	0	(30,349)	I
Dec. 31, 2003	2,876	(3,646)	38,859	1,559	1,580	9,568	10,790	4,530	66,115	I
Depreciation	52	59	2,270	90	0	36	84	22	2,612	I
Retirements	0	0	0	0	0	0	0	0	0	

I Updated to reflect 2003 actual costs.

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

GENERAL PLANT

	Structures &	Office Furniture & Equipment		Transportation Equipment		Heavy Work	Tools & Work			
	Improvements	General	Computers	Autos	Patrol Aircraft	Equipment	Equipment	Communication	Total	
Jan. 31, 2004	2,929	(3,588)	41,128	1,649	1,580	9,603	10,874	4,552	68,727	I
Depreciation	52	59	2,283	90	0	36	84	22	2,626	I
Retirements	0	0	0	0	0	0	0	0	0	
February 28	2,981	(3,529)	43,412	1,739	1,580	9,639	10,958	4,574	71,354	I
Depreciation	52	59	2,297	90	0	36	84	22	2,640	I
Retirements	0	0	0	0	0	0	0	0	0	
March 31	3,033	(3,470)	45,709	1,828	1,580	9,675	11,043	4,596	73,994	I
Depreciation	52	59	2,311	90	0	36	84	22	2,654	I
Retirements	(18)	0	0	0	0	0	0	0	(18)	
April 30	3,068	(3,411)	48,020	1,918	1,580	9,711	11,127	4,618	76,631	I
Depreciation	53	59	2,325	90	0	36	85	22	2,669	I
Retirements	(18)	0	0	0	0	0	0	0	(18)	I
May 31	3,103	(3,352)	50,345	2,007	1,580	9,746	11,212	4,640	79,282	I
Depreciation	53	59	2,339	90	0	36	85	22	2,683	I
Retirements	(18)	0	0	0	0	0	0	0	(18)	
June 30	3,138	(3,294)	52,684	2,097	1,580	9,782	11,297	4,662	81,947	I
Depreciation	53	59	2,353	90	0	36	85	22	2,697	I
Retirements	0	0	0	0	0	0	0	0	0	
July 31, 2004	3,191	(3,235)	55,037	2,187	1,580	9,818	11,382	4,684	84,644	I
Depreciation	53	59	2,367	90	0	36	86	22	2,711	I
Retirements	0	0	0	0	0	0	0	0	0	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

TransCanada
In business to deliver

CALCULATION OF MONTH - END ACCUMULATED DEPRECIATION BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

GENERAL PLANT

	Structures & Improvements	Office Furniture & Equipment General	Office Furniture & Equipment Computers	Transportation Equipment Autos	Transportation Equipment Patrol Aircraft	Heavy Work Equipment	Tools & Work Equipment	Communication	Total	
August 31, 2004	3,244	(3,176)	57,404	2,276	1,580	9,854	11,468	4,706	87,355	I
Depreciation	50	59	2,381	90	0	36	86	22	2,723	I
Retirements	0	0	0	58	0	0	0	0	58	
September 30	3,293	(3,117)	59,784	2,423	1,580	9,889	11,554	4,728	90,135	I
Depreciation	50	59	2,394	90	0	36	86	22	2,737	I
Retirements	0	0	0	58	0	0	0	0	58	
October 31	3,343	(3,059)	62,179	2,570	1,580	9,925	11,640	4,750	92,930	I
Depreciation	50	59	2,408	112	0	36	86	22	2,773	I
Retirements	0	0	0	58	0	0	0	0	58	
November 30	3,393	(3,000)	64,587	2,740	1,580	9,961	11,727	4,772	95,760	I
Depreciation	48	59	2,422	112	0	36	86	22	2,785	I
Retirements	0	(460)	(25,956)	58	0	0	(240)	0	(26,598)	
Dec. 31, 2004	3,441	(3,401)	41,053	2,909	1,580	9,997	11,573	4,794	71,946	I
Balance as at Dec. 31, 2001	11,096	(3,758)	36,652	1,010	1,580	9,008	10,435	3,591	69,614	
Depreciation	1,683	1,915	79,707	2,445	0	945	2,451	1,186	90,333	I
Retirements	(9,337)	(1,559)	(75,306)	(546)	0	44	(1,313)	17	(88,000)	I
Transfers	0	0	0	0	0	0	0	0	0	
Dec. 31, 2004	3,441	(3,401)	41,053	2,909	1,580	9,997	11,573	4,794	71,946	I

General Plant Depreciation	2002	20,059	
	2003	37,963	I
	2004	32,310	I
General Plant Retirements	2002	(31,439)	
	2003	(30,083)	I
	2004	(26,479)	

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	NEB ACCOUNT NUMBERS 465	467	TOTAL	
	(a)	(b)	(c)	(d)	
1	December 2003	(21,486)	(1,759)	(23,246)	I
2	January	(21,429)	(1,753)	(23,182)	I
3	February	(21,372)	(1,746)	(23,119)	I
4	March	(21,315)	(1,740)	(23,055)	I
5	April	(21,258)	(1,733)	(22,992)	I
6	May	(21,201)	(1,727)	(22,928)	I
7	June	(21,144)	(1,720)	(22,865)	I
8	July	(21,087)	(1,714)	(22,801)	I
9	August	(21,030)	(1,707)	(22,738)	I
10	September	(20,973)	(1,701)	(22,674)	I
11	October	(20,916)	(1,694)	(22,611)	I
12	November	(20,859)	(1,688)	(22,547)	I
13	December	(26,302)	(1,681)	(27,984)	I
14	Average in the Test Year	(21,567)	(1,720)	(23,288)	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

CASH WORKING CAPITAL
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	AMOUNT	
	(a)	(b)	
1	Total Operations, Maintenance and Administrative Expense	260,825	l
	Deduct:		
2	Non-Funded Pension Expense/Post Emp't Benefits (Schedule 5.3.8, Sheet 3 of 4)	(9,631)	l
3	Insurance Expense Net of Deductibles	5,239	l
4	Total Deducts	(4,392)	l
5	Net Operations, Maintenance and Administrative Expense	265,217	l
6	29/365th for Cash Working Capital	20,970	l

l Updated to reflect impact of 2003 actuals on 2004 amounts, and updated 2004 insurance deductible, NEB Cost Recovery, and Pension funding and expense.

GOODS AND SERVICES TAX, NET
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	GST RECEIVABLE	GST PAYABLE	NET RECEIVABLE/ PAYABLE	REVENUE CANADA SETTLEMENT PAYMENT/(REFUND)	TOTAL	
	(a)	(b)	(c)	(d)	(e)	(f)	
1	December, 2003					(4,130)	l
2	January	1,132	(5,765)	(4,633)	4,130	(4,633)	l
3	February	1,163	(5,765)	(4,602)	4,633	(4,602)	l
4	March	1,158	(5,765)	(4,607)	4,602	(4,607)	l
5	April	1,160	(5,765)	(4,605)	4,607	(4,605)	l
6	May	1,219	(5,765)	(4,546)	4,605	(4,546)	l
7	June	1,235	(5,765)	(4,530)	4,546	(4,530)	l
8	July	1,237	(5,765)	(4,528)	4,530	(4,528)	l
9	August	1,227	(5,765)	(4,538)	4,528	(4,538)	l
10	September	1,239	(5,765)	(4,526)	4,538	(4,526)	l
11	October	1,198	(5,765)	(4,567)	4,526	(4,567)	l
12	November	1,224	(5,765)	(4,541)	4,567	(4,541)	l
13	December	1,217	(5,765)	(4,548)	4,541	(4,548)	l
14	Average in The Test Year					(4,531)	l

l Updated to reflect impact of 2003 actuals on opening balances and activity for 2004.

MATERIALS AND SUPPLIES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	AMOUNT	
	(a)	(b)	
1	December, 2003	29,042	I
2	January	29,198	
3	February	29,156	
4	March	29,114	
5	April	29,072	
6	May	29,030	
7	June	28,988	
8	July	28,946	
9	August	28,904	
10	September	28,862	
11	October	28,280	
12	November	28,778	
13	December	28,740	
14	Average in the Test Year	28,932	I

I Updated to reflect impact of 2003 actuals on 2004 opening balances.

PREPAYMENTS
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	AMOUNT	
	(a)	(b)	
1	December, 2003	1,944	I
2	January	1,490	
3	February	1,113	
4	March	736	
5	April	494	
6	May	114	
7	June	4,126	
8	July	3,749	
9	August	3,372	
10	September	2,995	
11	October	2,618	
12	November	2,241	
13	December	1,994	
14	Average in the Test Year	2,076	I

I Updated to reflect impact of 2003 actuals on opening balances for 2004.

REGULATORY DEFERRED COSTS
AVERAGE UNAMORTIZED REGULATORY DEFERRED BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	AMOUNT INCLUDED IN RATE BASE		SCHEDULE REFERENCE
	(a)	(b)		(c)
	Miscellaneous Deferred Items			
1	Debt, Discount and Expense (Schedule 5.3.8, Sheet 2 of 4)	28,438		
2	Trust Deed Amendment Expense (Schedule 5.3.8, Sheet 2 of 4)	37		
3	Total	28,475		Sched. 5.3 Line 13
4	Operating and Debt Service Deferrals (Schedule 5.3.8, Sheet 4 of 4)	(30,439)	l	Sched. 5.3 Line 14
5	Non-Funded Pension Expense and Post Employment Benefits (Schedule 5.3.8, Sheet 3 of 4)	41,325	l	Sched. 5.3 Line 15

l Updated to reflect 2003 actual deferrals and revised 2004 pension funding and expense.

(UNFUNDED)/PREFUNDED PENSION LIABILITY AND POST EMPLOYMENT BENEFITS LIABILITY
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	(UNFUNDED)/PREFUNDED PENSION LIABILITY EXPENSE	FUNDING	TOTAL	POST EMPLOYMENT BENEFITS LIABILITY EXPENSE	FORECAST	TOTAL	PENSION AND POST EMPLOYMENT BENEFITS LIABILITY TOTAL	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	December, 2003			44,248			(7,741)	36,507	I
2	January	(1,256)	2,301	45,293	(398)	156	(7,983)	37,310	I
3	February	(1,256)	2,301	46,338	(398)	156	(8,225)	38,113	I
4	March	(1,256)	2,301	47,383	(398)	156	(8,467)	38,916	I
5	April	(1,256)	2,301	48,428	(398)	156	(8,709)	39,719	I
6	May	(1,256)	2,301	49,473	(398)	156	(8,951)	40,522	I
7	June	(1,256)	2,301	50,518	(398)	156	(9,193)	41,325	I
8	July	(1,256)	2,301	51,563	(398)	156	(9,435)	42,128	I
9	August	(1,256)	2,301	52,608	(398)	156	(9,677)	42,931	I
10	September	(1,256)	2,301	53,653	(398)	156	(9,919)	43,734	I
11	October	(1,256)	2,301	54,698	(398)	156	(10,161)	44,537	I
12	November	(1,256)	2,301	55,743	(398)	156	(10,403)	45,340	I
13	December	(1,259)	2,305	56,789	(398)	156	(10,645)	46,144	I
14	Average in The Test Year			50,518			(9,193)	41,325	I
15	Non-Funded Pension Expense and Post Employment Benefit Expense	(15,075)	27,616		(4,776)	1,866			I

I Updated to reflect impact of 2003 actuals on 2004 opening balances and updated estimates for 2004 pension funding and expense.

CALCULATION OF AVERAGE OPERATING AND DEBT SERVICE DEFERRAL BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	2003 DEFERRALS	
	(a)	(b)	
1	December, 2003	(60,877)	I
2	January	(55,804)	I
3	February	(50,731)	I
4	March	(45,658)	I
5	April	(40,585)	I
6	May	(35,512)	I
7	June	(30,439)	I
8	July	(25,366)	I
9	August	(20,293)	I
10	September	(15,220)	I
11	October	(10,147)	I
12	November	(5,074)	I
13	December	0	
14	Average in The Test Year	(30,439)	I

I Updated to reflect actual 2003 deferrals.

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 6

INCOME TAXES

TransCanada has included flow-through taxes related to its Mainline operations in its Revenue Requirement as allowed by the Board in Order TG-3-82.

Schedule 6.1

Schedule 6.1 provides the flow-through income taxes for the base year ended December 31, 2002. It also includes recovery of the Large Corporation Tax (LCT).

Schedule 6.2

Schedule 6.2 provides the flow-through income taxes for the actual year ended December 31, 2003. It also includes recovery of the LCT.

Schedule 6.3

Schedule 6.3 provides the flow-through income taxes for the test year ending December 31, 2004. It also includes recovery of the LCT.

The following explanations are provided for the income tax calculations shown in Schedule 6.3.

- Mainline tax costs are calculated based upon a projected income tax rate of 35.932%. In December 2003, the Ontario Government passed legislation increasing the Ontario tax rate from 11% to 14%. (Refer to schedule 6.3.1).
- The Utility Income Tax Requirement is calculated as the Mainline taxable amount times the tax rate divided by the result of 1 minus the tax rate. To this product is added the recovery of LCT and the Non-allowed Provincial Capital Tax.
- The equity component of operating Mainline income (Schedule 6.3, line 2) is calculated by multiplying the return on rate base by the ratio of the equity

component of the rate of return on rate base to the total rate of return on rate base.

- Line 4 of schedule 6.3 shows the test year amount for LCT. The LCT is calculated based upon the estimated capitalization of TransCanada's Mainline operations as at December 31, 2004. The year end capitalization and the calculation of LCT is summarized on schedule 6.3.7.

The LCT is included in the Mainline tax requirement on schedule 6.3 as this tax is not deductible for income tax purposes and as such must be added back in the tax calculation to determine the total tax requirement.

Change in Presentation for Utility Income Tax Requirement

Schedules 6.1, 6.2 and 6.3

A presentation change has been made to the way the Utility Income Tax Requirement and LCT are reflected in this application. In previous applications, the income tax rate did not include a federal surtax of 1.12% as the amount arising from this surtax was deducted in the form of a Federal Surtax deduction when applied to the LCT amount. For presentation purposes, TransCanada did not include the Federal Surcharge in the determination of the overall tax rate nor did it apply the Federal Surtax deduction to the LCT determination as the amounts resulting from these calculations were equal and offsetting and had no impact to the total amount of tax incorporated in its tolls.

However, tax legislation announced during 2003 provides for phasing out LCT by reducing the LCT rate over a number of years. The LCT rate for 2004 has been reduced from the 2003 rate of 0.225% to 0.200%. Current legislation further provides that the rate will be further reduced to 0.175% for 2005, 0.125% for 2006, 0.0625% for 2007, and nil thereafter. While the LCT is being phased out, the 1.12%

federal surtax, which is normally deducted in computing LCT, will remain in effect. A tax rate presentation change has been made in this application to reflect the change in methodology required to account for the fact that the 1.12% permanent federal surtax will no longer be part of a LCT determination after the LCT phase out.

This change in presentation has a neutral effect on the overall Utility Income Tax Requirement amount determined.

Schedules affected by this change in presentation methodology are Base Year, Actual Year, and Test Year Schedules:

Schedules 6.1, 6.2 and 6.3	Schedule of Flow-Through Income Tax
Schedules 6.1.1, 6.2.1 and 6.3.1	Calculation of Current Income Tax Rate
Schedules 6.1.7, 6.2.7 and 6.3.7	Calculation of Federal Large Corporations Tax

Site Remediation Costs

Certain Site Remediation Costs (which include permanent deactivation of compressor unit costs and environmental cleanup costs) that are capitalized into rate base are being deducted for tax purposes. As such 2003 Actual and the 2004 Test Year Income Tax determination have included these costs as current year deductions for income tax purposes. For accounting purposes the cost of the site restorations will be treated as normal retirement costs and as such will be included in Accumulated Depreciation consistent with the treatment of similar costs in accordance with the Gas Pipeline Uniform Accounting Regulations.

SCHEDULE OF FLOW-THROUGH INCOME TAXES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

LINE NO.	PARTICULARS	AMOUNT	SCHEDULE REFERENCE
	(a)	(b)	(c)
1	Return On Rate Base	789,692 I	5.2
2	Equity Component: (3.23 / 9.23 * 789,692)	276,349 I	
	Add:		
3	Depreciation	419,834 I	7.2
4	Large Corporation Tax	13,878 I	6.2.7
5	Non-allowed Provincial Capital Tax	716 I	6.2.3
6	Non-allowed Amortization of Debt Discount & Expense and Foreign Exchange Costs	9,014 I	6.2.2
7	Other Expenses	(17,519) I	6.2.3
8	Sub-total	425,923	
	Deduct:		
9	Capital Cost Allowance	387,776 I	6.2.4
10	Site Remediation Costs	30,509 I	
11	Benefits Capitalized	668 I	
12	Eligible Capital Expenses	639	6.2.3
13	Interest AFUDC	515 I	6.2.5
14	Issue Costs	614 I	6.2.3
15	Sub-total	420,721 I	
16	Total Taxable Amount	281,551 I	
17	Tax Requirement thereon at 0.3757 / 0.6243	169,436 I	6.2.1
18	Add: Non-allowed Provincial Capital Tax	716 I	6.2.3
19	Recovery of Large Corporation Tax	13,878 I	6.2.7
20	Utility Income Tax Requirement	184,030 I	

I Updated to reflect 2003 actual amounts.

CALCULATION OF CURRENT INCOME TAX RATE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003

LINE NO.	PARTICULARS									
1	Allocation of taxable income to provinces based on composite average of salaries paid within each province and kilometers of pipe located within each province applied to the current provincial statutory income tax rate.									
2	PROVINCE	SALARIES ($000)	PERCENTAGE	KILOMETERS OF PIPELINE	PERCENTAGE	COMPOSITE AVERAGE %	INCOME TAX RATE %	EFFECTIVE RATE %		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		
3	British Columbia	1,560	0.861	201.58	1.31	1.08	13.500	0.146	I	
4	Alberta	150,582	83.088	1.78	0.01	41.56	12.625	5.246	I	
5	Saskatchewan	5,149	2.841	3,766.13	24.45	13.65	17.000	2.321	I	
6	Manitoba	4,132	2.280	2,805.64	18.22	10.25	16.000	1.640	I	
7	Ontario	18,108	9.992	8,029.42	52.13	31.06	12.500	3.883	I	
8	Quebec (incl. 1.6% surcharge)	1,701	0.939	597.91	3.88	2.41	8.929	0.215	I	
9	Total	181,232	100.00	15,402.46	100.00	100.00				
10	Composite Provincial Tax Rate							13.450	I	
11	Federal Tax Rate							23.000		
12	Federal Surtax							1.120		
13	Income Tax Rate for the Year Ended December 31							37.570	I	

I Updated to reflect 2003 actual amounts.

CALCULATION OF NON-ALLOWED
DEBT DISCOUNT AND EXPENSE AND FOREIGN EXCHANGE COSTS l
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
1	Amortization of Debt, Discount and Expense - Debt (Rate of Return Schedule 2.2.2)	2,658
2	Amortization of Debt, Discount and Expense - Junior Subordinated Debentures (Rate of Return Schedule 3.2.2)	568
3	Amortization of Debt, Discount and Expense on Early Debt Redemption (Revenue Requirement Schedule 15.2)	5,894
4	Foreign Exchange Costs (Revenue Requirement Schedule 15.2)	(106)
5	Total	9,014

l No change from 2003 forecast.

INCOME TAX EXPENSE SCHEDULE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

LINE NO.	PARTICULARS		AMOUNT	
	(a)		(b)	
	A. CALCULATION OF ELIGIBLE CAPITAL EXPENSES			
1	Unamortized Balance at January 1, 2003		9,134	
2	Additions - Land Rights (@75%)		0	
3	Balance at December 31, 2003		9,134	
4	Amount Available for Tax Deduction at 7% of Line 3		639	
5	Unamortized Balance at January 1, 2004		8,495	
	B. CALCULATION OF OTHER EXPENSES			
6	50% Meal and Entertainment	- Expenses non-deductible	1,022	I
7	Non Funded Pension Expense	(Schedule 5.2.8, Sheet 3 of 4)	(21,633)	I
8	Post Employment Benefits	(Schedule 5.2.8, Sheet 3 of 4)	3,092	I
9	Total Non-Allowed Expenses		(17,519)	I
	C. CALCULATION OF FINANCING COSTS			
10	Medium Term Notes		614	
11	Preferred Securities		0	
12	Proposed Debt		0	
13	Total Financing Costs		614	
	D. CALCULATION OF ADDITIONAL ALBERTA TAX ON NON-ALLOWED EXPENSES			
14	Non-Allowed Provincial Capital Tax 13,654 X .4156 X .12625		716	I

I Updated to reflect 2003 actual amounts.

SCHEDULE OF CAPITAL COST ALLOWANCE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

LINE NO.	CLASS	UNDEPRECIATED CAPITAL COST OPENING BALANCE	ADDITIONS (NET)	BALANCE BEFORE CLAIM	MAXIMUM CLAIM	CLOSING BALANCE	
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Class 1 - Full (4%)	4,177,499		4,177,499	167,100	4,018,396	I
2	- Half Year		8,160	8,160	163		I
3	Class 2 - Full (6%)	524,857		524,857	31,491	493,366	
4	Class 3 - Full (5%)	27,167		27,167	1,358	25,809	I
5	Class 8 - Full (20%)	805,518		805,518	161,104	658,863	I
6	- Half Year		16,055	16,055	1,606		I
7	Class 9 - Full (25%)	0		0	0	0	
8	- Half Year		0	0	0		
9	Class 10 - Full (30%)	53,594		53,594	16,078	38,499	I
10	- Half Year		1,157	1,157	174		I
11	Class 12 - Full (100%)	5,344		5,344	5,344	1,534	I
12	- Half Year		3,069	3,069	1,535		I
13	Class 13 - Full (S/L)	11,826		11,826	1,822	10,022	I
14	- Half Year		19	19	1		I
15	Total	5,605,805	28,461	5,634,265	387,776	5,246,489	I

CAPITAL COST ALLOWANCE RECONCILIATION

LINE NO.	PARTICULARS		AMOUNT	
	(a)		(b)	
16	Transfers to GPIS in 2003 (including Overhead, excluding AFUDC)		29,974	I
17	Regulated General Plant Additions in 2003		4,702	I
	Adjustments			
18	Net Proceeds - Retirements	1,636		I
19	Site Remediation Costs	(1,615)		I
20	Benefits Capitalized	(668)		I
21	Contributions in Aid of Construction	(3,792)		I
22	Land	(297)		I
23	Materials & Supplies	(1,478)		I
24	Total Adjustments		(6,215)	I
25	Capital Cost Allowance Additions per Line 15 above		28,461	I

I Updated to reflect 2003 actual amounts.

CALCULATION OF INTEREST AFUDC
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

Interest AFUDC

$$= \frac{\text{Interest Component of Rate of Return}}{\text{Rate of Return}} \times \text{AFUDC}$$

$$= \frac{6.00}{9.23} \times \$792$$ I

$$= \$515$$ I

I Updated to reflect 2003 actual amounts.

CONTINUITY OF UTILITY CAPITAL LOSS CARRY FORWARD
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I

LINE NO.	PARTICULARS	AMOUNT ($000)
	(a)	(b)
1	Capital Loss Carried Forward from 2002	81,893
2	Capital Gain for 2003 (Schedule 15.2, Line 8)	(106)
3	Total Capital Loss Carried Forward	81,787

I No change from 2003 forecast.

CALCULATION OF FEDERAL LARGE CORPORATION TAX (LCT)
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

LINE NO.	PARTICULARS	Amount	Note	
	As at December 31			
1	Deemed Debt	5,643,281		I
2	Common Equity	2,779,527		I
3	Capital Tax Deduction	(10,000)		
4	Taxable Capital	8,412,808		I
5	Tax Rate	0.225%		
6	LCT Expense before Surtax Deduction	18,929		I
7	Federal Surtax Deduction	(5,051)	(1)	I
8	LCT Expense	13,878		I

Note

(1) The Federal Surtax is Calculated as follows:

Total Taxable amount	281,551	Schedule 6.2, Line 16	I
Tax Requirement before Non-allowed PCT and Recovery of LCT	169,436	Schedule 6.2, Line 17	I
Total Subject to Surtax	450,987		I
Surtax	1.12%		
Federal Surtax	5,051		I

I Updated to reflect 2003 actual amounts.

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SCHEDULE OF FLOW-THROUGH INCOME TAXES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS		AMOUNT		SCHEDULE REFERENCE
	(a)		(b)		(c)
1	Return On Rate Base		780,075	l	5.3
2	Equity Component:	(4.4 / 9.51 * 780,075)	360,918	l	
	Add:				
3	Depreciation		415,160	l	7.3
4	Large Corporation Tax		9,545	l	6.3.7
5	Non-allowed Provincial Capital Tax		668	l	6.3.3
6	Non-allowed Amortization of Debt Discount & Expense and Foreign Exchange Costs		(38,970)		6.3.2
7	Other Expenses		(8,922)	l	6.3.3
8	Sub-total		377,481	l	
	Deduct:				
9	Capital Cost Allowance		343,910	l	6.3.4
10	Site Remediation Costs		23,038	l	
11	Benefits Capitalized		1,224		
12	Eligible Capital Expenses		595		6.3.3
13	Interest AFUDC		189	l	6.3.5
14	Issue Costs		0		6.3.3
15	Sub-total		368,956	l	
16	Total Taxable Amount		369,443	l	
17	Tax Requirement thereon at	0.35932 / 0.64068	207,199	l	6.3.1
18	Add: Non-allowed Provincial Capital Tax		668	l	6.3.3
19	Recovery of Large Corporation Tax		9,545	l	6.3.7
20	Utility Income Tax Requirement		217,412	l	

l Updated to reflect the impact of 2003 actuals on opening balances for 2004 return and depreciation, updated pension funding and expense estimates, and tax rate changes.

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CALCULATION OF CURRENT INCOME TAX RATE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS							
1	Allocation of taxable income to provinces based on composite average of salaries paid within each province and kilometers of pipe located within each province applied to the current provincial statutory income tax rate.							
2	PROVINCE	SALARIES ($000)	PERCENTAGE	KILOMETERS OF PIPELINE	PERCENTAGE	COMPOSITE AVERAGE %	INCOME TAX RATE %	EFFECTIVE RATE %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3	British Columbia	1,560	0.861	201.58	1.31	1.08	13.500	0.146 I
4	Alberta	150,582	83.088	1.78	0.01	41.55	12.500	5.194 I
5	Saskatchewan	5,149	2.841	3,766.13	24.45	13.65	17.000	2.320 I
6	Manitoba	4,132	2.280	2,805.64	18.22	10.25	15.500	1.589 I
7	Ontario	18,108	9.992	8,029.42	52.13	31.06	14.000	4.348 I
8	Quebec (incl. 1.6% surcharge)	1,701	0.939	597.91	3.88	2.41	8.900	0.215 I
9	Total	181,232	100.00	15,402.46	100.00	100.00		
10	Composite Provincial Tax Rate							13.812 I
11	Federal Tax Rate							21.000
12	Federal Surtax							1.120
13	Income Tax Rate for the Test Year Ending December 31							35.932 I

I Updated to reflect impact of 2003 actual amounts and the 2004 Ontario provincial tax rate adjustment reflecting the cancellation of the expected rate reduction.

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INCOME TAX EXPENSE SCHEDULE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS		AMOUNT	
	(a)		(b)	
	A. CALCULATION OF ELIGIBLE CAPITAL EXPENSES			
1	Unamortized Balance at January 1, 2004		8,495	
2	Additions - Land Rights (@75%)		0	
3	Balance at December 31, 2004		8,495	
4	Amount Available for Tax Deduction at 7% of Line 3		595	
5	Unamortized Balance at January 1, 2005		7,900	
	B. CALCULATION OF OTHER EXPENSES			
6	50% Meal and Entertainment	- Expenses non-deductible	709	
7	Non Funded Pension Expense	(Schedule 5.3.8, Sheet 3 of 4)	(12,541)	I
8	Post Employment Benefits	(Schedule 5.3.8, Sheet 3 of 4)	2,910	I
9	Total Non-Allowed Expenses		(8,922)	I
	C. CALCULATION OF FINANCING COSTS			
10	Medium Term Notes		0	
11	Preferred Securities		0	
12	Proposed Debt		0	
13	Total Financing Costs		0	
	D. CALCULATION OF ADDITIONAL ALBERTA TAX ON NON-ALLOWED EXPENSES			
14	Non-Allowed Provincial Capital Tax 12,857 X .4155 X .1250		668	I

I Updated to reflect revisions to 2004 Pension and Post Employment Benefits, and Ontario capital tax rate change.

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SCHEDULE OF CAPITAL COST ALLOWANCE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	CLASS	UNDEPRECIATED CAPITAL COST OPENING BALANCE	ADDITIONS (NET)	BALANCE BEFORE CLAIM	MAXIMUM CLAIM	CLOSING BALANCE	
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Class 1 - Full (4%)	4,018,396		4,018,396	160,736	3,877,727	I
2	- Half Year		20,477	20,477	410		I
3	Class 2 - Full (6%)	493,366		493,366	29,602	463,764	
4	Class 3 - Full (5%)	25,809		25,809	1,290	24,519	
5	Class 8 - Full (20%)	658,863		658,863	131,773	544,374	I
6	- Half Year		19,204	19,204	1,920		I
7	Class 9 - Full (25%)	0		0	0	0	
8	- Half Year		0	0	0		
9	Class 10 - Full (30%)	38,499		38,499	11,550	30,684	I
10	- Half Year		4,394	4,394	659		I
11	Class 12 - Full (100%)	1,534		1,534	1,534	2,595	
12	- Half Year		5,190	5,190	2,595		
13	Class 13 - Full (S/L)	10,022		10,022	1,822	8,551	I
14	- Half Year		370	370	19		I
15	Total	5,246,489	49,635	5,296,124	343,910	4,952,214	I

CAPITAL COST ALLOWANCE RECONCILIATION

LINE NO.	PARTICULARS		AMOUNT	
	(a)		(b)	
16	Transfers to GPIS in 2004 (including Overhead, excluding AFUDC)		45,466	I
17	Regulated General Plant Additions in 2004		10,815	I
	Adjustments			
18	Net Proceeds - Retirements	23,116		
19	Site Remediation Costs	(23,038)		I
20	Benefits Capitalized	(1,224)		
21	Contributions in Aid of Construction	(5,500)		
22	Total Adjustments		(6,646)	I
23	Capital Cost Allowance Additions per Line 15 above		49,635	I

I Updated to reflect impact of 2003 actuals on opening balances and activity for 2004.

CALCULATION OF INTEREST AFUDC
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

Interest AFUDC

$$= \frac{\text{Interest Component of Rate of Return}}{\text{Rate of Return}} \times \text{AFUDC}$$

$$= \frac{5.11}{9.51} \times \$351 \quad \text{l}$$

$$= \$189 \quad \text{l}$$

l Reflects changes in capitalization resulting from 2003 actual update and impact on 2004.

CALCULATION OF FEDERAL LARGE CORPORATION TAX (LCT)
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	Amount	Note	
	As at December 31			
1	Deemed Debt	4,830,940		I
2	Common Equity	3,220,627		I
3	Capital Tax Deduction	(50,000)		
4	Taxable Capital	8,001,567		I
5	Tax Rate	0.200%		
6	LCT Expense before Federal Surtax Deduction	16,003		I
7	Federal Surtax Deduction	(6,458)	(1)	I
8	LCT Expense	9,545		I

Note

(1) The Federal Surtax is Calculated as follows:

Total Taxable amount	369,443	Schedule 6.3, Line 16	I
Tax Requirement before Non-allowed PCT and Recovery of LCT	207,199	Schedule 6.3, Line 17	I
Total Subject to Surtax	576,642		I
Surtax	1.12%		
Federal Surtax	6,458		I

I Updated to reflect impact of 2003 actual ending balances on 2004.

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 7

DEPRECIATION

Schedule 7.1

Schedule 7.1 provides the monthly depreciation expense for the base year ended December 31, 2002.

Schedule 7.2

Schedule 7.2 provides the monthly depreciation expense for the actual year ended December 31, 2003.

Schedule 7.3

Schedule 7.3 provides the monthly depreciation expense for the test year ending December 31, 2004.

The 2003 and 2004 depreciation expense are calculated using rates and methodology approved in the Board's RH-1-2002 Decision. The composite depreciation rate for 2003 and 2004 is approximately 3.42%.

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DEPRECIATION EXPENSE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

LINE NO.	PARTICULARS	DEPRECIATION RATE (%)	JAN 1	JAN 31	FEB 28	MARCH 31	APRIL 30	MAY 31	JUNE 30
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Intangible Plant		8,567	8,567	8,567	8,567	8,567	8,567	8,567
	Depreciation Expense	2.44		17	17	17	17	17	17
	Transmission Plant								
2	Land Rights		33,158	33,158	33,158	33,158	33,158	33,158	33,158
	Depreciation Expense	2.73		76	75	75	75	75	75
3	Mains		8,693,798	8,701,366	8,701,363	8,701,329	8,702,864	8,702,922	8,704,064
	Depreciation Expense	2.82		20,451	20,448	20,448	20,448	20,452	20,452
4	Compressor		3,281,328	3,283,447	3,283,403	3,283,674	3,281,917	3,281,879	3,281,363
	Depreciation Expense	3.99		10,917	10,924	10,923	10,924	10,919	10,918
5	Measuring and Regulating		110,636	110,658	110,661	110,676	110,652	110,656	110,749
	Depreciation Expense	3.82		354	352	352	352	352	352
6	Communication Equipment - Transmission		13,414	13,471	13,471	13,471	13,471	13,471	13,471
	Depreciation Expense	5.70		64	64	64	64	64	64
	General Plant								
7	Structures & Improvements		12,609	12,609	12,609	12,609	12,609	12,609	12,611
	Depreciation Expense	R/L *		(146)	53	53	53	53	53
8	Furniture & Equip - General		7,693	7,693	7,693	7,693	7,692	7,692	7,692
	Depreciation Expense	11.39		74	73	73	73	73	73
9	Furniture & Equip - Computers		125,675	126,215	126,707	127,290	127,810	128,188	128,566
	Depreciation Expense	26.57		2,783	2,793	2,806	2,818	2,830	2,838
10	Vehicles		9,910	8,201	8,201	8,249	8,314	8,315	8,315
	Depreciation Expense	11.52		7	88	88	79	80	80
11	Patrol Aircraft		870	870	870	870	870	870	870
	Depreciation Expense	0.00		0	0	0	0	0	0
12	Heavy Work Equipment		22,749	22,750	22,759	22,759	22,761	22,770	22,776
	Depreciation Expense	1.87		35	35	35	35	35	35
13	Tools & Work Equipment		28,596	28,615	28,615	28,615	28,615	28,583	28,596
	Depreciation Expense	3.65		86	87	87	87	87	87
14	Communication Equipment - General		7,839	7,839	7,839	7,839	7,839	7,838	7,838
	Depreciation Expense	3.27		22	21	21	21	21	21
15	Total Depreciation Expense			34,739	35,032	35,044	35,049	35,059	35,067
16	AFUDC and Overhead			0	0	0	0	0	0
17	Contributions In Aid of Construction			(77)	(63)	(63)	(63)	(63)	(63)
18	Net Depreciation Expense			34,662	34,969	34,981	34,986	34,996	35,004

* Remaining Life
No change from 2003 Forecast.

DEPRECIATION EXPENSE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000s)

LINE NO.	PARTICULARS	JULY 31	AUG 31	SEPT 30	OCT 31	NOV 30	DEC 31	TOTAL	
	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Intangible Plant	8,567	8,567	8,567	8,567	8,567	8,567		
	Depreciation Expense	17	17	17	17	17	17	209	
	Transmission Plant								
2	Land Rights	33,159	33,159	33,159	33,159	33,159	33,159		I
	Depreciation Expense	75	75	75	75	75	75	905	
3	Mains	8,704,446	8,704,789	8,705,775	8,705,872	8,707,769	8,708,037		I
	Depreciation Expense	20,455	20,455	20,456	20,459	20,459	20,463	245,445	I
4	Compressor	3,284,142	3,284,124	3,285,268	3,286,341	3,286,952	3,289,025		I
	Depreciation Expense	10,916	10,925	10,925	10,929	10,932	10,935	131,087	I
5	Measuring and Regulating	110,750	110,710	110,257	110,257	109,996	109,996		I
	Depreciation Expense	353	353	353	351	351	350	4,225	I
6	Communication Equipment - Transmission	13,609	13,612	13,612	13,612	13,612	13,963		I
	Depreciation Expense	64	65	65	65	65	65	771	I
	General Plant								
7	Structures & Improvements	12,611	12,626	12,628	12,627	12,627	12,628		I
	Depreciation Expense	53	53	53	53	53	53	437	I
8	Furniture & Equip - General	7,692	7,692	7,692	7,692	7,692	6,194		
	Depreciation Expense	73	73	73	73	73	73	877	
9	Furniture & Equip - Computers	128,604	128,757	129,114	129,322	129,769	102,504		I
	Depreciation Expense	2,847	2,847	2,851	2,859	2,863	2,873	34,009	I
10	Vehicles	8,315	8,315	8,315	8,578	9,013	9,335		I
	Depreciation Expense	80	80	80	80	82	87	911	I
11	Patrol Aircraft	870	870	870	870	870	870		
	Depreciation Expense	0	0	0	0	0	0	0	
12	Heavy Work Equipment	22,790	22,791	22,795	22,870	22,880	22,949		I
	Depreciation Expense	35	36	36	36	36	36	426	
13	Tools & Work Equipment	28,598	28,598	28,624	28,578	28,703	27,692		I
	Depreciation Expense	87	87	87	87	87	87	1,044	
14	Communication Equipment - General	7,838	8,093	8,093	8,093	8,093	8,093		I
	Depreciation Expense	21	21	22	22	22	22	259	I
15	Total Depreciation Expense	35,076	35,088	35,093	35,105	35,116	35,137	420,606	I
16	AFUDC and Overhead	0	0	0	0	0	0	0	I
17	Contributions In Aid of Construction	(63)	(63)	(63)	(64)	(64)	(64)	(772)	I
18	Net Depreciation Expense	35,013	35,025	35,030	35,042	35,053	35,073	419,834	I

* Remaining Life
I Updated to reflect 2003 actual costs.

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DEPRECIATION EXPENSE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	DEPRECIATION RATE (%)	JAN 1	JAN 31	FEB 28	MARCH 31	APRIL 30	MAY 31	JUNE 30	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Intangible Plant		8,567	8,567	8,567	8,567	8,567	8,567	8,567	
	Depreciation Expense	2.44		17	17	17	17	17	17	
	Transmission Plant									
2	Land Rights		33,159	33,159	33,159	33,159	33,159	33,159	33,159	I
	Depreciation Expense	2.73		75	75	75	75	75	75	
3	Mains		8,708,037	8,711,283	8,714,602	8,718,134	8,718,220	8,719,514	8,720,033	I
	Depreciation Expense	2.82		20,464	20,472	20,479	20,488	20,488	20,491	I
4	Compressor		3,289,025	3,290,419	3,292,164	3,294,124	3,295,597	3,296,705	3,298,038	I
	Depreciation Expense	3.99		10,936	10,941	10,946	10,953	10,958	10,962	I
5	Measuring and Regulating		109,996	110,003	110,015	110,031	110,052	110,076	110,096	I
	Depreciation Expense	3.82		350	350	350	350	350	350	I
6	Communication Equipment - Transmission		13,963	13,989	14,016	14,052	14,097	14,148	14,196	I
	Depreciation Expense	5.70		66	66	67	67	67	67	I
	General Plant									
7	Structures & Improvements		12,628	12,628	12,628	12,653	12,680	12,709	12,711	I
	Depreciation Expense	R/L *		52	52	52	52	53	53	I
8	Furniture & Equip - General		6,194	6,194	6,194	6,194	6,194	6,194	6,194	
	Depreciation Expense	11.39		59	59	59	59	59	59	
9	Furniture & Equip - Computers		102,504	103,130	103,756	104,382	105,008	105,635	106,261	I
	Depreciation Expense	26.57		2,270	2,283	2,297	2,311	2,325	2,339	I
10	Vehicles		9,335	9,335	9,335	9,335	9,335	9,335	9,335	I
	Depreciation Expense	11.52		90	90	90	90	90	90	I
11	Patrol Aircraft		870	870	870	870	870	870	870	
	Depreciation Expense	0		0	0	0	0	0	0	
12	Heavy Work Equipment		22,949	22,949	22,949	22,949	22,949	22,949	22,949	I
	Depreciation Expense	1.87		36	36	36	36	36	36	
13	Tools & Work Equipment		27,692	27,692	27,728	27,776	27,938	27,980	28,059	I
	Depreciation Expense	3.65		84	84	84	84	85	85	I
14	Communication Equipment - General		8,093	8,093	8,093	8,093	8,093	8,093	8,093	I
	Depreciation Expense	3.27		22	22	22	22	22	22	I
15	Total Depreciation Expense			34,522	34,548	34,576	34,605	34,625	34,646	I
16	AFUDC and Overhead			0	1	2	2	3	3	I
17	Contributions In Aid of Construction			(63)	(63)	(63)	(63)	(63)	(63)	
18	Net Depreciation Expense			34,458	34,485	34,514	34,544	34,564	34,585	I

* Remaining Life
I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

DEPRECIATION EXPENSE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000s)

LINE NO.	PARTICULARS	JULY 31	AUG 31	SEPT 30	OCT 31	NOV 30	DEC 31	TOTAL	
	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Intangible Plant	8,567	8,567	8,567	8,567	8,567	8,567		
	Depreciation Expense	17	17	17	17	17	17	209	
	Transmission Plant								
2	Land Rights	33,159	33,159	33,159	33,159	33,159	33,159		I
	Depreciation Expense	75	75	75	75	75	75	905	
3	Mains	8,720,679	8,722,830	8,724,787	8,726,664	8,729,957	8,733,741		I
	Depreciation Expense	20,492	20,494	20,499	20,503	20,508	20,515	245,892	I
4	Compressor	3,299,333	3,300,671	3,302,075	3,303,425	3,304,837	3,306,253		I
	Depreciation Expense	10,966	10,970	10,975	10,979	10,984	10,989	131,558	I
5	Measuring and Regulating	110,116	110,134	110,158	110,185	110,211	110,232		I
	Depreciation Expense	350	351	351	351	351	351	4,205	I
6	Communication Equipment - Transmission	14,237	14,277	14,323	14,369	14,425	14,477		I
	Depreciation Expense	67	68	68	68	68	69	808	I
	General Plant								
7	Structures & Improvements	12,732	12,756	12,781	12,836	12,891	12,945		I
	Depreciation Expense	53	53	50	50	50	48	618	
8	Furniture & Equip - General	6,194	6,194	6,194	6,194	6,194	5,734		
	Depreciation Expense	59	59	59	59	59	59	705	
9	Furniture & Equip - Computers	106,887	107,513	108,139	108,765	109,392	84,062		I
	Depreciation Expense	2,353	2,367	2,381	2,394	2,408	2,422	28,150	I
10	Vehicles	9,335	9,335	9,335	11,635	11,635	11,635		I
	Depreciation Expense	90	90	90	90	112	112	1,120	I
11	Patrol Aircraft	870	870	870	870	870	870		
	Depreciation Expense	0	0	0	0	0	0	0	
12	Heavy Work Equipment	22,949	22,949	22,949	22,949	22,949	22,949		I
	Depreciation Expense	36	36	36	36	36	36	429	
13	Tools & Work Equipment	28,135	28,308	28,364	28,373	28,376	28,136		I
	Depreciation Expense	85	86	86	86	86	86	1,023	
14	Communication Equipment - General	8,093	8,093	8,093	8,093	8,093	8,093		I
	Depreciation Expense	22	22	22	22	22	22	265	I
15	Total Depreciation Expense	34,666	34,686	34,707	34,731	34,776	34,801	415,888	I
16	AFUDC and Overhead	3	3	4	4	5	5	34	I
17	Contributions In Aid of Construction	(63)	(63)	(63)	(63)	(63)	(63)	(762)	
18	Net Depreciation Expense	34,605	34,626	34,648	34,672	34,717	34,742	415,160	I

* Remaining Life
I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

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REVENUE REQUIREMENT
TAB 8

INVENTORY MANAGEMENT PROGRAM
FOR THE BASE YEAR ENDED DECEMBER 31, 2002
ACTUAL YEAR ENDED DECEMBER 31, 2003, l
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

Ln. No.	Particulars	2002 Base Year	2003 Actual Year	2004 Test Year
	(a)	(b)	(c)	(d)
1	Total Inventory Management Program	12,000	12,000	8,000

l No Change from 2003 forecast.

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REVENUE REQUIREMENT
TAB 9

GAS-RELATED AND ELECTRIC COSTS

Gas-related costs include provincial sales tax on fuel gas where applicable, and electricity expense associated with electric drive compressors. Schedules 9.1, 9.2 and 9.3 show costs for the Base Year, Actual Year and Test Year respectively.

Cost Variances Base Year to Actual Year

Cost variances related to Other Electric Units (Schedules 9.1, 9.2 lines 9 -12) from the base year to the actual year are primarily due to differences in unit utilization influenced by the rise in gas price, discretionary capacity as well as changes in the electricity prices year over year.

The electricity supply contracts for the units at stations 9, 17 and 41 include minimum annual commitments as well as price escalation factors. The increase in the costs for stations 9 and 17 is due to high electric unit utilization as a result of commodity price spread favoring electric fired compression in Saskatchewan. Due to low hydro-electric costs in Manitoba, the Station 41 electric units remain as preferred units resulting in higher utilization.

The increase in the costs for Stations 52 and 123 is due primarily to the managed utilization of these units in Ontario's deregulated electricity market. Upon market opening May 1, 2002, Stations 52 and 123 contracted for energy under the Transitional Rate Option leveraging favorable electricity pricing throughout 2003. However, TransCanada experienced reduced utilization of electric fired compression in the fourth quarter associated with declining commodity gas prices and reduced flows, higher electricity prices and technical failures at station 52 in December.

The variances in costs related to Montreal Line Electric Units (Schedules 9.1, 9.2, line 7) are due to changes in compressor unit utilization from year to year. This is a function of the demand for firm and discretionary capacity on the Montreal line/North Bay shortcut during the winter season.

Cost Variances Actual Year to Test Year

The variance in cost related to Other Electric Units (Schedules 9.2, 9.3 lines 9 -12) from the actual year to the test year are due primarily to differences in the utilization of the electric units as a function of anticipated changes in the electricity and gas price.

Total sales tax on gas fuel is projected to decrease in 2004 relative to 2003, principally due to a reduction in forecast throughput for 2004.

GAS RELATED AND ELECTRIC FUEL EXPENSE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003

LINE NO.	PARTICULARS		SASKATCHEWAN	MANITOBA	QUEBEC	2003 ACTUAL YEAR	
	(a)		(b)	(c)	(d)	(e)	
1	Volume - GJ		21,727,851	8,677,392	878,112		I
2	Alberta Border Price - $/GJ		6.501	6.832	6.271		I
3	Compressor Fuel Valuation ($000)		$141,250	$59,286	$5,507		I
4	Sales Tax Rate		6.00%	7.00%	7.50%		
5	Total Sales Tax on Gas Fuel ($000)		$8,475	$4,150	$413	$13,038	I
6	Electric Power	- Electric Energy Aftercoolers				1,026	I
7		- Montreal Line Electric Units				2,518	I
8		- Other Electric Units					
9		- Stn. 9E & 17E				27,334	I
10		- Stn. 41F & 41G				15,835	I
11		- Stn. 52C				7,406	I
12		- Stn. 123C				5,690	I
13	Total Electric Power ($000)					$59,809	I
14	Total Gas Related and Electric Fuel Expense ($000)					$72,847	I

I Updated to reflect 2003 actual costs.

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REVENUE REQUIREMENT
TAB 10

MUNICIPAL AND PROVINCIAL CAPITAL TAXES

Schedule 10.0 shows the municipal and provincial capital taxes for the base year ended December 31, 2002, actual year ended December 31, 2003 and the test year ending December 31, 2004.

Municipal tax increases from 2002 to 2003 reflect actual mill rate changes as illustrated in the following table:

Table 1
2003 Actual vs. 2002 Actual ($000)

Province	Mill Rate	Reassessments	Facility Additions	Total
Alberta	17	0	0	17
Saskatchewan	1,089	0	0	1,089
Manitoba	509	0	0	509
Ontario	(498)	0	0	(498)
Quebec	3	0	0	3
Total	1,120	0	0	1,120

Municipal tax increases from 2003 to 2004 reflect forecasted mill rate increases and re-assessments as illustrated in the following table:

Table 2
2004 Test Year vs. 2003 Actual ($000)

Province	Mill Rate	Reassessments	Facility Additions	Total
Alberta	(1)	0	0	(1)
Saskatchewan	764	0	0	764
Manitoba	687	0	0	687
Ontario	1281	1,080	0	2361
Quebec	17	0	0	17
Total	2,748	1,080	0	3,828

The increase in municipal taxes in the province of Ontario for 2004 reflects a projected inflation rate of 2% and a potential for reassessment of compressor facilities. TransCanada does not anticipate a reassessment on the unorganized provincial land tax area in northern Ontario in 2004. This has reduced the potential for substantial tax increases during the 2004 tax year. However, the potential for reassessments, local government restructuring and tax policies for subsequent years remains uncertain. TransCanada continues to make representation to various provincial governments, both specifically on behalf of the Mainline and through pipeline industry committees. TransCanada also continues to communicate with assessment authorities in all provinces with respect to assessment practices, policies and applications.

Provincial capital taxes have been based on the estimated total Paid-up Capital and reflect the declining rate base. Pending legislation for future reductions to Ontario capital tax (from 0.3% to 0.27%) was not passed prior to the recent change in the Ontario government and is not expected to be reintroduced.

MUNICIPAL AND PROVINCIAL CAPITAL TAXES
FOR THE BASE YEAR ENDED DECEMBER 31, 2002
ACTUAL YEAR ENDED DECEMBER 31, 2003
AND TEST YEAR ENDING DECEMBER 31, 2004
($000)

Ln. No.	Particulars	2002 Base Year	Change	2003 Actual Year		Change	2004 Test Year	
	(a)	(b)	(c)	(d)		(e)	(f)	
	Municipal Taxes							
1	Alberta	1,336	17	1,353	l	(1)	1,352	
2	Saskatchewan	18,017	1,089	19,106		764	19,870	
3	Manitoba	16,258	509	16,767	l	687	17,454	
4	Ontario	64,567	(498)	64,069	l	2,361	66,430	
5	Quebec	789	3	792	l	17	809	
6	Total Municipal Taxes	100,967	1,120	102,087	l	3,828	105,915	
	Provincial Capital Taxes							
7	Saskatchewan	4,873	(300)	4,573	l	(266)	4,307	l
8	Manitoba	2,955	(165)	2,790	l	(169)	2,621	l
9	Ontario	5,379	(306)	5,073	l	(308)	4,765	l
10	Quebec	1,569	(351)	1,218	l	(54)	1,164	l
11	British Columbia	105	(105)	0		0	0	
12	Total Provincial Capital Taxes	14,881	(1,227)	13,654	l	(797)	12,857	l
13	Total Municipal and Provincial Capital Taxes	115,848	(107)	115,741	l	3,031	118,772	l

l Updated to reflect actual 2003 costs, and the impact of 2003 actual capitalization on opening balances for 2004.
The Ontario Capital Tax rate has been adjusted from 0.27% to 0.30% as the new Ontario government
did not legislate the tabled change for 2004.

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REVENUE REQUIREMENT
TAB 11

REGULATORY AMORTIZATION

Regulatory amortizations for 2002, 2003 and 2004 are contained in the following schedules:

Schedule 11.1

Schedule 11.1 provides a summary of regulatory amortizations approved by the Board for recovery in 2002 Tolls.

Schedule 11.2

Schedule 11.2 provides a summary of regulatory amortizations approved by the Board for recovery in 2003 Tolls.

Schedule 11.2.1

Schedule 11.2.1 provides a summary of regulatory amortizations by major category approved by the Board for recovery in 2003 Tolls.

Schedule 11.2.2

Schedule 11.2.2 provides a summary of the 2001 deferred revenue surplus variance and 2002 deferred revenue deficiency variance carried forward and approved by the Board for recovery in 2003 Tolls.

Schedule 11.2.3

Schedule 11.2.3 provides a summary of the 2001 deferred balances arising from the Board's RH-4-2001 Decision and approved by the Board for recovery in 2003 Tolls.

2003 Incentive and Flow-Through Based Deferral Accounts - Actual

Schedule 11.3

Schedule 11.3 provides a summary of actual amounts deferred in 2003 in accordance with deferral accounts approved in the RH-1-2002 Decision. The annual amounts include actual results to December 2003,

Schedule 11.3.1

A summary of Flow-Through and Incentive Based 2003 Deferral Accounts are shown by major category.

Flow-through variances reflect the difference between 2003 actual costs and the costs included in the NEB RH-1-2002 Decision. OM&A cost variances are not subject to flow-through treatment and, accordingly, the variance at column (d) line 13 Schedule 11.3.1 excludes any OM&A variance.

Schedule 11.3.2

Schedule 11.3.2 provides details and variance explanations supporting the flow-through deferred balances.

Schedule 11.3.3

Schedule 11.3.3 shows the monthly carrying charges on deferred balances and have been calculated on the average of each month's opening and closing balances.

Schedule 11.3.4

Schedule 11.3.4 provides a summary of the 2003 deferred revenue surplus variance carried forward for amortization in the 2004 Test Year.

Schedule 11.4

Schedule 11.4 provides the request and justification for deferral accounts for the 2004 Test Year.

REGULATORY AMORTIZATIONS
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($ 000)

Line No.	Description	Amount	Schedule Reference
	(a)	(b)	
1	2002 Operating and Debt Service Deferrals	(67,901)	11.2.1
2	2002 Revenue Deficiency Variance	(2,987)	11.2.2
3	2001 Revenue Surplus Variance	(90)	11.2.2
4	2001 Cost of Capital Variance	1,837	11.2.3
5	Total Regulatory Amortizations	(69,141)	

l No change from 2003 forecast.

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REGULATORY AMORTIZATIONS -2002 DEFERRED BALANCES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l

Settlement Article Ref.	Line No.	Description	2002 Actual	2002 Tolls Application	Deferred Principal	Carrying Charges	Total Deferred
		(a)	(b)	(c)	(d)	(e)	(f)
		Flow-Through Based Deferrals					
		Costs					
	1	Transmission by Others	373,750	382,784	(9,034)	(252)	(9,286)
	2	OM&A	209,832	216,254	N/A	N/A	N/A
	3	Gas Related and Electric	53,427	69,365	(15,938)	(796)	(16,734)
	4	FST Replacement Costs	22,365	21,235	1,130	46	1,176
	5	Pipe Integrity and Insurance Deductible	25,861	38,471	(12,610)	(1,219)	(13,829)
	6	Mainline Share - MCBA Compliance Audit	4	-	4	-	4
	7	Depreciation	362,274	362,907	(633)	15	(618)
	8	Income Tax	153,765	160,232	(6,467)	(282)	(6,749)
	9	Return	821,643	821,349	294	13	307
	10	NEB Cost Recovery	7,728	7,728	-	(62)	(62)
	11	Municipal and Other Tax	115,848	114,407	1,441	(394)	1,047
	12	Regulatory Amortizations	(100,107)	(100,107)	-	-	-
	13	Inventory Management Program	12,000	12,000	-	-	-
	14	Gains on Storage Gas	(512)	(512)	-	-	-
	15	Pressure Charges	4,625	4,625	-	-	-
Article 4.2	16	Total Costs	2,062,503	2,110,738	(41,813)	(2,931)	(44,744)
		Revenues					
Article 4.4 (b)	17	Non-Discretionary	74,402	64,490	(9,912)	(391)	(10,303)
Article 4.4 (c)	18	Discretionary	96,216	17,000	(79,216)	(2,285)	(81,501)
Article 4.5 (b)	19	Firm	1,970,268	2,032,612	62,344	1,582	63,926
	20	Total Revenue	2,140,886	2,114,102	(26,784)	(1,094)	(27,878)
		Other					
Article 4.2	21	Foreign Exchange on US Debt Interest			1,756	146	1,902
Article 4.2	22	Foreign Exchange on UK Debt Interest			400	18	418
	23	Total Other Flow-Through Items			2,156	164	2,320
	24	Total Flow-Through Deferred Balance			(66,441)	(3,861)	(70,302)
		Incentive Based Deferrals					
Article 10.2	25	Foreign Exchange Management Program			(1,059)	(15)	(1,074)
Article 10.3	26	Interest Rate Management Program			(6,502)	(78)	(6,580)
Article 5.1	27	Severance Program			(2,042)	(88)	(2,130)
Article 9.1	28	Revenue /Asset Management			5,000	377	5,377
	29	Fuel Gas Incentive			6,745	201	6,946
	30	Total Incentive Based Deferrals			2,142	397	2,539
	31	Total 2002 Deferred Balances to be Applied to the 2003 Test Year			(64,299)	(3,464)	(67,763)
	32	Carrying Charges in 2003			-	(138)	(138)
	33	Total			(64,299)	(3,602)	(67,901)

l No change from 2003 forecast.

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REGULATORY AMORTIZATION OF
2001 AND 2002 DEFERRED REVENUE VARIANCES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

LINE NO.	PARTICULARS	AMOUNT
	(a)	(b)
	2002 Deferred Revenue Deficiency Variance	
1	2002 Revenue Deficiency - Estimate for Tolls	(15,956)
2	2002 Revenue Deficiency - Actual	(13,072)
3	Deferred Revenue Deficiency	(2,884)
4	Carrying Charges in 2002 @ 2.73%	(50)
5	Total	(2,934)
6	Carrying Charges in 2003 @ 3.6%	(53)
7	Total (Schedule 11.2, Line 2)	(2,987)
	2001 Deferred Revenue Surplus Variance	
8	2001 Revenue Surplus - Estimate for Tolls	12,578
9	2001 Revenue Surplus - Actual	12,667
10	Deferred Revenue Surplus	(89)
11	Carrying Charges in 2002 @ 2.73%	1
12	Total	(88)
13	Carrying Charges in 2003 @ 3.6%	(2)
14	Total (Schedule 11.2, Line 3)	(90)

I No change from 2003 forecast.

REGULATORY AMORTIZATIONS
ESTIMATE/ACTUAL VARIANCE ON 2001 DEFERRED BALANCES
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

Line No.	Description	Actual	Approved	Variance
	(a)	(b)	(c)	(d)
	Flow-Through Based Deferrals			
	Costs			
1	Transmission by Others	(4,510)	(4,510)	-
2	Gas Related and Electric	(5,728)	(5,727)	(1)
3	FST Replacement Costs	426	418	8
4	Pipe Integrity and Insurance Deductible	(8,274)	(8,266)	(8)
5	Mainline Share - MCBA Compliance Audit	43	43	-
6	Depreciation	(222)	(222)	-
7	Income Tax	(4,620)	(4,382)	(238)
8	Return	(1,984)	(3,887)	1,903
9	NEB Cost Recovery	139	139	-
10	Municipal and Other Tax	(9,441)	(9,430)	(11)
11	Inventory Management Program	4,062	4,061	1
12	Gains on Storage Gas	(2,952)	(2,951)	(1)
13	Total Costs	(33,061)	(34,714)	1,653
	Revenues			
14	Non-Discretionary	349	389	(40)
15	Discretionary	(80,103)	(80,068)	(35)
16	Firm	14,008	13,904	104
17	Total Revenue	(65,746)	(65,775)	29
	Other			
18	Foreign Exchange on US Debt Interest	4,721	4,719	2
19	Foreign Exchange on UK Debt Interest	(71)	(71)	-
20	Total Other flow-through Items	4,650	4,648	2
	Incentive Based Deferrals			
21	Foreign Exchange Management Program	688	688	-
22	Interest Rate Management Program	(4,221)	(4,221)	-
23	Severance Program	(806)	(805)	(1)
24	Revenue /Asset Management	5,209	5,208	1
25	Merger Agreement 2001 Benefit	(5,075)	(5,072)	(3)
26	Total Incentive Based Deferrals	(4,205)	(4,202)	(3)
27	Total 2001 Deferred Balances	(98,362)	(100,043)	1,681
28	Carrying Charges in 2002 on Foreign Exchange and Interest Rate Management Programs	(64)	(64)	-
29	Total	(98,426)	(100,107)	1,681
30	Carrying Charges on Variance in 2002			156
31	Total Amount to be Amortized in 2003			1,837

I No Change from 2003 forecast.

REGULATORY AMORTIZATIONS
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($ 000)

Line No.	Description	Amount		Schedule Reference
	(a)	(b)		
1	2003 Operating and Debt Service Deferrals	(66,869)	l	11.3.1
2	2003 Revenue Surplus Variance	(1,657)	l	11.3.4
3	Total Regulatory Amortizations	(68,526)	l	

l Updated to reflect 2003 actual amounts.

REGULATORY AMORTIZATIONS -2003 DEFERRED BALANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

Line No.	Description	2003 Actual	2003 Decision	Deferred Principal	Carrying Charges	Total Deferred		Reference Schedule	Note
	(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)
	Flow-Through Based Deferrals								
	Costs								
1	Transmission by Others	360,015	385,491	(25,476)	(924)	(26,400)	I	11.3.2	(1)
2	Storage Operating Costs	11,371	10,790	581	34	615	I	11.3.2	(2)
3	Pipe Integrity and Insurance Deductible	45,200	47,155	(1,955)	(759)	(2,714)	I	11.3.2	(3)
4	NEB Cost Recovery	10,732	10,732	-	(86)	(86)	I		
5	Return	789,692	796,214	(6,522)	(277)	(6,799)	I	11.3.2	(4)
6	Income Tax	184,030	195,472	(11,442)	(525)	(11,967)	I	11.3.2	(5)
7	Depreciation	419,834	421,971	(2,137)	(90)	(2,227)	I	11.3.2	(6)
8	Inventory Management Program	12,000	12,000	-	-	-			
9	Gas Related and Electric	72,847	53,797	19,050	1,088	20,138	I	11.3.2	(7)
10	Municipal and Provincial Capital Tax	115,741	117,521	(1,780)	(138)	(1,918)	I	11.3.2	(8)
11	Regulatory Amortizations	(69,141)	(69,141)	-	-	-			
12	Gains on Storage Gas	(953)	(953)	-	-	-			
13	OM&A	228,107	230,273	N/A	-	N/A	I		
14	Regulatory Proceedings Costs	2,490	2,400	90	2	92	I	11.3.2	(9)
15	Debt Redemption Costs	5,788	-	5,788	249	6,037		11.3.2	(10)
16	Pressure Charges	3,772	3,772	-	-	-			
17	Total Costs	2,191,525	2,217,494	(23,803)	(1,426)	(25,229)	I		
	Revenues								
18	Non-Discretionary	66,117	63,194	(2,923)	(129)	(3,052)	I	11.3.2	(11)
19	Discretionary	251,794	238,813	(12,981)	(981)	(13,962)	I	11.3.2	(12)
20	Firm	1,923,658	1,913,267	(10,391)	153	(10,238)	I	11.3.2	(13)
21	Total Revenue	2,241,569	2,215,274	(26,295)	(957)	(27,252)	I		
	Other								
22	Foreign Exchange on US Debt Interest			(12,740)	(419)	(13,159)	I	11.3.2	(14)
23	Foreign Exchange on UK Debt Interest			311	23	334	I	11.3.2	(15)
24	Total Other Flow-Through Items			(12,429)	(396)	(12,825)	I		
25	Total Flow-Through Deferred Balance			(62,527)	(2,779)	(65,306)	I		
	Incentive Based Deferrals								
26	Foreign Exchange Management Program			319	6	325		11.3.2	(16)
27	Interest Rate Management Program			(6,108)	(110)	(6,218)	I	11.3.2	(17)
28	Fuel Gas Incentive			4,412	17	4,429	I	11.3.2	(18)
29	Total Incentive Based Deferrals			(1,377)	(87)	(1,464)	I		
30	Total 2003 Deferred Balances to be Applied to the 2004 Test Year			(63,904)	(2,866)	(66,770)	I		
31	Carrying Charges in 2004 *			-	(99)	(99)	I		
32	Total			(63,904)	(2,965)	(66,869)	I		

* Carrying charges at 3.35% on the 2004 average unamortized Interest Rate and Foreign Exchange Management Program deferred balances.

I Updated to reflect 2003 actual amounts.

2003 DEFERRALS - EXPLANATORY NOTES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

(1) Transmission By Others	2003 Actual	2003 Decision	Variance	
Great Lakes	170,081	170,463	(382)	
Union	41,744	40,242	1,502	(a)
TQM	87,456	87,850	(394)	
Exchange	65,257	86,936	(21,679)	(b)
Assignment of TBO capacity	(4,523)	-	(4,523)	(c)
Total Transmission By Others	360,015	385,491	(25,476)	
Carrying Charges			(924)	
Total			(26,400)	

(a) Higher Union overrun costs resulting from increased flow and lower M12 contracts, partially offset by lower costs resulting from Union 2000-2002 deferral account refunds, a reduction in M12 contracts of 35,800 GJ/d effective November 1, 2003 and reduced rates pursuant to RP-2002-0130.
(b) Lower GLGT costs associated with an improvement to the Canadian dollar ($1.384 vs $1.51 included in 2003 Tolls)
(c) Cost savings achieved through the assignment of capacity.

(2) Storage Operating Costs	2003 Actual	2003 Decision	Variance	
NGTL	1,000	1,000	-	
EnCana	10,371	9,790	581	(a)
Total Costs	11,371	10,790	581	
Carrying Charges			34	
Total			615	

(a) Increased costs primarily due to higher than anticipated injection commodity charges.

(3) Pipe Integrity and Insurance Deductible	2003 Actual	2003 Decision	Variance	
SCC and Related Costs (Non-research)	19,817	23,246	(3,429)	(a)
Pipeline Integrity Research	2,121	2,234	(113)	
Corrosion and Other Pipe Integrity Programs	22,609	21,147	1,462	(b)
Insurance Deductible	653	528	125	
	45,200	47,155	(1,955)	
Carrying Charges			(759)	
Total			(2,714)	

(a) Continued ability to maximize bundling and scheduling opportunities on the 2003 hydrotesting program, resulting in savings of approximately 10%. Payment of an SCC in-line inspection in 2003 was not required.

(b) The unfavourable variance resulted from 2003 corrosion dig costs exceeding 2003 budget estimates. The primary reason for this variance was digs in rock ditches on the Mainline. During 2003, an improved dig estimating tool was developed which will improve future dig cost estimating.

2003 DEFERRALS - EXPLANATORY NOTES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

(4) Return	2003 Actual	2003 Decision	Variance	
Average Rate Base	8,555,713	8,579,897	(24,184)	(a)
Overall Rate of Return	9.23%	9.28%	-0.05%	(b)
Return	789,692	796,214	(6,522)	
Carrying Charges			(277)	
Total			(6,799)	

(a) Lower average rate base due to changes in scope and timing of pipe and compression projects and higher credits for Contributions in Aid of Construction.
(b) Lower rate of return on debt due to the redemption of the 8.75% Junior Subordinated Debentures in July 2003.

(5) Income Tax	2003 Actual	2003 Decision	Variance	
Equity Return	276,349	277,131	(782)	
Additions	425,923	421,342	4,581	(a)
Deductions	(420,721)	(397,301)	(23,420)	(b)
Taxable Income	281,551	301,172	(19,621)	
Taxes thereon @ 37.57 vs 37.557	169,436	181,143	(11,707)	
Recovery of Large Corporation Tax	13,878	13,603	275	
Non-Allowed Provincial Capital Tax	716	726	(10)	
Utility Income Tax Requirement	184,030	195,472	(11,442)	
Carrying Charges			(525)	
Total			(11,967)	

(a) Additional Debt Issue Cost Amortization in 2003 due to the redemption of the 8.75% Junior Subordinated Debentures in July 2003.
(b) Higher deductions principally due to current year deduction for site remediation costs.

(6) Depreciation Expense	2003 Actual	2003 Decision	Variance	
Depreciation	419,834	421,971	(2,137)	(a)
Carrying Charges			(90)	
Total			(2,227)	

(a) Lower depreciation expense associated with lower capital spending.

(7) Gas Related and Electric	2003 Actual	2003 Decision	Variance	
Sales Tax	13,038	8,797	4,241	(a)
Electric	59,809	45,000	14,809	(b)
Total Gas Related and Electric	72,847	53,797	19,050	
Carrying Charges			1,088	
Total			20,138	

(a) The increase in sales tax expense is primarily due to higher gas prices.
(b) Higher electric unit utilization in Saskatchewan and Manitoba as a result of lower hydro-electric costs.

2003 DEFERRALS - EXPLANATORY NOTES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

(8) Municipal and Provincial Capital Tax	2003 Actual	2003 Decision	Variance	
Municipal Tax	102,087	103,590	(1,503)	(a)
Provincial Capital Tax	13,654	13,931	(277)	
Total Municipal and Other Tax	115,741	117,521	(1,780)	
Carrying Charges			(138)	
Total			(1,918)	

(a) Local government restructuring and tax policy changes in Ontario did not materialize in 2003, resulting in lower costs compared to tolls. This decrease is partially offset by an increase in municipal taxes for Saskatchewan.

(9) Regulatory Proceedings	2003 Actual	2003 Decision	Variance	
External Legal Costs	1,545	800	745	(a)
Other Regulatory Proceedings Costs	945	1,600	(655)	(b)
Total Regulatory Proceedings Costs	2,490	2,400	90	
Carrying Charges			2	
Total			92	

(a) Primarily higher external legal costs related to the RH-1-2002, 2003 Tolls Application.
(b) Regulatory costs associated with the 2004 tolls application were lower than expected in 2003.

(10) Debt Redemption Costs	2003 Actual	2003 Decision	Variance	
Amortization of Debt Discount and Expense	5,894	-	5,894	(a)
Foreign Exchange Gain on Debt Redemption	(106)	-	(106)	(b)
Total Debt Redemption Costs	5,788	-	5,788	
Carrying Charges			249	
Total			6,037	

Redemption of US $160.million 8.75% Junior Subordinated Debentures on July 3, 2003
(a) Debt Issue Costs remaining at time of redemption.
(b) Historic Exchange Rate of $1.36293 vs Actual Exchange Rate of $1.36227 at time of redemption.

(11) Non-Discretionary Miscellaneous Revenue	2003 Actual	2003 Decision	Variance	
Long Term Winter Firm Service	1,336	1,333	3	
Sale of Delivery Pressure	19,361	16,638	2,723	(a)
Sales Meter Station Charges	91	41	50	
Storage Transportation Service	41,557	41,410	147	
Total	62,345	59,422	2,923	
Non-Discretionary Revenue Deferred			(2,923)	
Carrying Charges			(129)	
Total Deferred			(3,052)	

(a) Higher delivery pressure revenue principally due to unanticipated discretionary volumes.

2003 DEFERRALS - EXPLANATORY NOTES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

(12) Discretionary Miscellaneous Revenue

Downstream Diversions	23,671
Short Term Firm Transportation Service	70,231
Enhanced Capacity Release	17
Interruptible Service	151,748
Interruptible Backhaul	906
Daily Balancing Fees	2,852
STS Overrun	2,067
Parking & Loan Service	302
Total Discretionary Revenue	251,794
Amount included in 2003 Tolls	238,813
Net Discretionary Revenue	12,981
Discretionary Revenue Deferred	(12,981)
Carrying Charges	(981)
Total Deferred	(13,962)

(13) Firm Revenue Demand and Commodity	2003 Actual	2003 Decision	Variance	
Firm Demand				
Saskatchewan Zone	4,337	3,065	1,272	
Manitoba Zone	35,416	35,041	375	
Western Zone	20,876	21,595	(719)	
Northern Zone	93,140	95,349	(2,209)	
Eastern Zone	703,624	697,838	5,786	
Dawn to Consumers	2,049	2,020	29	
St. Clair to Consumers	2,023	0	2,023	
St. Clair to Union	2,664	2,483	181	
Herbert to GMI	820	0	820	
Herbert to SSDA	231	0	231	
Dawn to Iroquois	1,322	428	894	
Empress to Emerson	86,212	79,006	7,206	
Empress to Iroquois	350,508	355,174	(4,666)	
Empress to Cornwall	17,288	11,568	5,720	
Empress to Phillipsburg	14,129	12,618	1,511	
Other			367	
Total			18,821	(a)
US Gen New England Contract Termination - Iroquois			(5,816)	(b)
Total FT Demand			13,005	
FT Demand Deferral			(13,005)	
FT Commodity Deferral			2,614	
			(10,391)	
Carrying Charges			153	
Total Firm Service Revenue Deferral			(10,238)	

(a) Additional revenues resulting from contracts awarded during the Open Season between September 15th and October 27th, 2003 and delivery point shifts, partially offset by a Union Gas contract non-renewal.

(b) US Gen New England contract default and termination September 5, 2003.

Amount included in Tolls	22,654
Revenues	(15,378)
Financial Assurances	(1,460)
Net shortfall in demand revenue in 2003	5,816

2003 DEFERRALS - EXPLANATORY NOTES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

(14) Foreign Exchange on US$ Debt Interest	2003 Actual	2003 Decision	Variance
Total US$	118,778	118,778	
Rates	41.39%	52.12%	
Total Exchange	49,168	61,908	(12,740)
Carrying Charges			(419)
Total Deferred			(13,159)

(15) Foreign Exchange on UK Debt Interest	2003 Actual	2003 Decision	Variance
Total UK	4,125	4,125	
Rates	128.53%	120.99%	
Total Exchange	5,302	4,991	311
Carrying Charges			23
Total Deferred			334

(16) Foreign Exchange Management Program	2003 Amount
TBO	(1,077)
US Debt Interest Payment	(1,501)
UK Debt Interest Payment	(205)
Other (Gains)/Losses	2,123
Total Net Improvement Against Benchmark	(660)
Incentive Based deferred amount @ 50%	330
Gain on Option premiums @ 50%	(11)
Incentive Based Deferral Amount @ 50%	319
Carrying Charges	6
Total Deferred	325

(17) Interest Rate Management Program	2003 Amount
Total Gains on the Program	12,216
Incentive Based Deferral Amount @ 50%	(6,108)
Carrying Charges	(110)
Total Deferred	(6,218)

(18) Fuel Gas Incentive

	2003 Amount
Amount deferred	4,412
Carrying Charges	17
Total Deferred	4,429

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Operating Costs
2003 Deferred Balances & Carrying Charge Calculation
($000)

Ln. No.	Particulars	January	February	March	April	May	June	July	August	September	October	November	December	Total	
		Actual													
1	Municipal and Provincial Capital Taxes	(8,024)	(1,953)	8,007	(2,553)	(6,579)	6,597	413	2,584	12,975	1,380	(6,138)	(8,489)	(1,780)	I
2	Gas Related and Electric Fuel	2,117	3,074	3,767	2,726	357	2,454	2,365	2,055	(32)	(236)	1,274	(871)	19,050	I
3	Transmission By Others	(1,438)	(1,049)	(2,548)	(2,179)	(2,463)	(1,920)	(1,829)	(2,088)	(2,740)	(3,022)	(1,633)	(2,567)	(25,476)	I
4	NEB Cost Recovery	(894)	(895)	1,789	(894)	(895)	1,789	(894)	(895)	1,789	(894)	(895)	1,789	0	
5	Return on Rate Base	(395)	(427)	(453)	(456)	(476)	(522)	(567)	(592)	(613)	(660)	(687)	(674)	(6,522)	I
6	Income Tax	(996)	(855)	(868)	(882)	(896)	(916)	(950)	(961)	(986)	(1,014)	(1,052)	(1,066)	(11,442)	I
7	Depreciation	(335)	(71)	(82)	(100)	(115)	(131)	(161)	(176)	(203)	(224)	(257)	(282)	(2,137)	I
8	Pipeline Integrity & Insurance Deductible	(3,528)	(2,830)	(1,612)	(1,630)	(617)	(681)	(7)	(21)	1,137	2,663	522	4,649	(1,955)	I
9	Storage Operating Costs	(104)	(74)	(4)	699	262	16	(72)	(55)	(55)	(72)	(52)	92	581	I
10	Regulatory Proceedings costs	(217)	(144)	104	51	543	(23)	(43)	(161)	114	(118)	(177)	161	90	I
11	Debt Redemption Costs	0	0	0	0	0	0	5,778	10	0	0	0	0	5,788	
12	Total Amount Deferred	(13,814)	(5,224)	8,100	(5,218)	(10,879)	6,663	4,033	(300)	11,386	(2,197)	(9,095)	(7,258)	(23,803)	I
	Carrying Charge Determination														
13	Balance Forward	0	(14,444)	(21,180)	(12,473)	(17,838)	(25,794)	(21,707)	(17,739)	(17,622)	(3,578)	(5,306)	(17,407)	0	I
14	Additions	(14,389)	(6,600)	8,836	(5,249)	(7,789)	4,269	4,119	252	14,125	(1,694)	(12,014)	(4,323)	(20,457)	I
15	Carrying Charges @ 9.23%	(55)	(136)	(129)	(116)	(167)	(182)	(151)	(135)	(81)	(34)	(87)	(153)	(1,426)	I
16	Closing Balance	(14,444)	(21,180)	(12,473)	(17,838)	(25,794)	(21,707)	(17,739)	(17,622)	(3,578)	(5,306)	(17,407)	(21,883)	(21,883)	I
	Deferred Balance														
17	Balance Forward	0	(13,869)	(19,229)	(11,258)	(16,592)	(27,638)	(21,157)	(17,275)	(17,710)	(6,405)	(8,636)	(17,818)	0	I
18	Additions	(13,814)	(5,224)	8,100	(5,218)	(10,879)	6,663	4,033	(300)	11,386	(2,197)	(9,095)	(7,258)	(23,803)	I
19	Carrying Charges @ 9.23%	(55)	(136)	(129)	(116)	(167)	(182)	(151)	(135)	(81)	(34)	(87)	(153)	(1,426)	I
20	Closing Balance	(13,869)	(19,229)	(11,258)	(16,592)	(27,638)	(21,157)	(17,275)	(17,710)	(6,405)	(8,636)	(17,818)	(25,229)	(25,229)	I
21	Total Operating Costs Deferred													(25,229)	I

I Updated to reflect 2003 actual amounts.

Revenue Deferrals

2003 Deferred Balances & Carrying Charge Calculation
($000)

Ln. No.	Particulars	Actual January	February	March	April	May	June	July	August	September	October	November	December	Total	
1	FT Revenue	440	400	427	349	338	344	(1,123)	326	1,925	2,060	(6,811)	(9,066)	(10,391)	I
2	Non-Discretionary	(377)	(368)	(328)	(184)	(166)	(266)	(217)	(198)	(127)	(88)	(161)	(443)	(2,923)	I
3	Discretionary	(1,122)	(2,085)	(6,498)	(617)	(3,563)	(10,326)	268	2,189	10,460	7,595	2,934	(12,216)	(12,981)	I
4	Total Amount Deferred	(1,059)	(2,053)	(6,399)	(452)	(3,391)	(10,248)	(1,072)	2,317	12,258	9,567	(4,038)	(21,725)	(26,295)	I
	Carrying Charge Determination														
5	Balance Forward	0	0	(1,063)	(3,132)	(9,580)	(10,107)	(13,589)	(23,981)	(25,242)	(23,110)	(10,982)	(1,463)	0	I
6	Prior Months Activity	0	(1,059)	(2,053)	(6,399)	(452)	(3,391)	(10,248)	(1,072)	2,317	12,258	9,567	(4,038)	(4,570)	I
7	Carrying Charges @ 9.23%	0	(4)	(16)	(49)	(75)	(91)	(144)	(189)	(185)	(131)	(48)	(26)	(957)	I
8	Closing Balance	0	(1,063)	(3,132)	(9,580)	(10,107)	(13,589)	(23,981)	(25,242)	(23,110)	(10,982)	(1,463)	(5,527)	(5,527)	I
	Deferred Balance														
9	Opening Balance	0	(1,059)	(3,116)	(9,531)	(10,032)	(13,498)	(23,837)	(25,053)	(22,925)	(10,852)	(1,415)	(5,501)	0	I
10	Additions	(1,059)	(2,053)	(6,399)	(452)	(3,391)	(10,248)	(1,072)	2,317	12,258	9,567	(4,038)	(21,725)	(26,295)	I
11	Carrying Charges @ 9.23%	0	(4)	(16)	(49)	(75)	(91)	(144)	(189)	(185)	(131)	(48)	(26)	(957)	I
12	Closing Balance	(1,059)	(3,116)	(9,531)	(10,032)	(13,498)	(23,837)	(25,053)	(22,925)	(10,852)	(1,415)	(5,501)	(27,252)	(27,252)	I
13	Total Revenue Deferrals													(27,252)	I

Other Flow-Through Items

2003 Deferred Balances & Carrying Charge Calculation
($000)

Ln. No.	Particulars	Actual January	February	March	April	May	June	July	August	September	October	November	December	Total	
14	US $ Debt Interest	290	0	(960)	0	(718)	(1,952)	(2,936)	0	(2,856)	0	(1,681)	(1,927)	(12,740)	I
15	UK £ Debt Interest	0	0	296	0	0	0	0	15	0	0	0	0	311	I
16	Total Amount Deferred	290	0	(664)	0	(718)	(1,952)	(2,936)	15	(2,856)	0	(1,681)	(1,927)	(12,429)	I
	Deferred Balance														
17	Opening Balance	0	291	293	(371)	(374)	(1,097)	(3,065)	(6,036)	(6,068)	(8,981)	(9,050)	(10,807)	0	I
18	Additions	290	0	(664)	0	(718)	(1,952)	(2,936)	15	(2,856)	0	(1,681)	(1,927)	(12,429)	I
19	Carrying Charges @ 9.23%	1	2	(0)	(3)	(6)	(16)	(35)	(46)	(58)	(69)	(76)	(91)	(396)	I
20	Closing Balance	291	293	(371)	(374)	(1,097)	(3,065)	(6,036)	(6,068)	(8,981)	(9,050)	(10,807)	(12,825)	(12,825)	I
21	Total Foreign Exchange on US $ and UK £ Debt Interest Deferrals													(12,825)	I

I Updated to reflect 2003 actual amounts.

Interest Rate/Foreign Exchange Management Program
2003 Deferred Balances & Carrying Charge Calculation
($000)

Ln. No.	Particulars	Actual January	February	March	April	May	June	July	August	September	October	November	December	Total	
1	For. Exch. Program - 50% of variance	(209)	(186)	526	(96)	284	0	0	0	0	0	0	0	319	
2	Int.Rate Program (Gains)/Losses @ 50%	(537)	(435)	(899)	(473)	(490)	(533)	(490)	(460)	(462)	(417)	(474)	(438)	(6,108)	I
3	Total Amount Deferred	(746)	(621)	(373)	(569)	(206)	(533)	(490)	(460)	(462)	(417)	(474)	(438)	(5,789)	I
	Deferred Balance														
4	Opening Balance	0	(747)	(1,371)	(1,749)	(2,323)	(2,536)	(3,077)	(3,577)	(4,049)	(4,523)	(4,952)	(5,440)	0	I
5	Additions	(746)	(621)	(373)	(569)	(206)	(533)	(490)	(460)	(462)	(417)	(474)	(438)	(5,789)	I
6	Carrying Charges (1)	(1)	(3)	(5)	(5)	(7)	(8)	(10)	(12)	(12)	(12)	(14)	(15)	(104)	I
7	Closing Balance	(747)	(1,371)	(1,749)	(2,323)	(2,536)	(3,077)	(3,577)	(4,049)	(4,523)	(4,952)	(5,440)	(5,893)	(5,893)	I
8	Total Interest Rate/Foreign Exchange Management Program Deferrals													(5,893)	I

(1) Carrying Charges are calculated using the monthly average of the one month's bankers acceptance rate.

Other Incentive Based Deferrals
2003 Deferred Balances & Carrying Charge Calculation
($000)

Ln. No.	Particulars	Actual January	February	March	April	May	June	July	August	September	October	November	December	Total	
9	Fuel Gas Incentive	0	0	0	0	0	0	0	0	0	0	0	4,412	4,412	I
	Deferred Balance														
10	Balance Forward	0	0	0	0	0	0	0	0	0	0	0	0	0	
11	Additions	0	0	0	0	0	0	0	0	0	0	0	4,412	4,412	I
12	Carrying Charges @ 9.23%	0	0	0	0	0	0	0	0	0	0	0	17	17	I
13	Closing Balance	0	0	0	0	0	0	0	0	0	0	0	4,429	4,429	I
14	Total Other Incentive Based Deferrals													4,429	I

I Updated to reflect 2003 actual amounts.

REGULATORY AMORTIZATION OF
2003 DEFERRED REVENUE VARIANCES
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	AMOUNT	
	(a)	(b)	
	2003 Deferred Revenue Surplus Variance		
1	2003 Revenue Surplus - Estimate for Tolls	2,181	
2	2003 Revenue Surplus - Actual	3,781	
3	Deferred Revenue Surplus Variance	(1,600)	
4	Carrying Charges in 2003 @ 3.11%	(30)	I
5	Total	(1,630)	I
6	Carrying Charges in 2004 @ 3.35%	(27)	
7	Total (Schedule 11.3, Line 2)	(1,657)	I

I Updated to reflect 2003 actual amounts.

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 12

GAIN ON SALE OF GAS STORAGE

Schedule 12.0 shows the gains on the sale of storage gas for the base year ended December 31, 2002, actual year ended December 31, 2003, and test year ending December 31, 2004. No storage gas sales are anticipated for the test year ending December 31, 2004.

GAIN ON SALE OF STORAGE GAS FOR THE BASE YEAR ENDED
DECEMBER 31, 2002, ACTUAL YEAR ENDED DECEMBER 31, 2003 l
AND TEST YEAR ENDING DECEMBER 31, 2004

($ 000)

Ln. No.	Particulars	2002 Base Year	2003 Actual Year	2004 Test Year
	(a)	(b)	(c)	(d)
	Gain on Sale of Storage Gas			
1	Total Gain on Sale of Storage Gas	(512)	(953)	-

l No change from 2003 forecast.

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 13

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS

February Update

This update replaces forecast 2003 cost data with actual results for the year ended December 31, 2003. In addition, the following changes have been made to test year Operating Costs:

- Pension related costs have been updated for the latest actuarial assessment dated January, 2004 (Lines 15-16, Schedule 13.8). This has resulted in an increase to 2004 OM&A costs of $1.5 million.
- Long term incentive compensation amounts were updated using valuations consistent with those applied in actual 2003 results (Line 6, Schedule 13.8). This has resulted in an increase to 2004 OM&A costs of $1.6 million.
- Correction of errors affecting Plant Engineering ($0.5 million decrease to Line 2, Schedule 13.2) and Customer Service ($0.3 million increase to Line 3, Schedule 13.5), resulting in a net decrease of $0.2 million. Correction of these errors has also resulted in minor changes to related support costs.

After incorporating the above-noted changes, OM&A costs for 2004 are now forecast to be $212.3 million, with an increase of $2.7 million compared with amounts included in the Application dated January 26, 2004.

1.0 Introduction

This section provides information on Mainline Operations, Maintenance and Administrative (OM&A) costs for the years 2002 to 2004. The OM&A cost schedules in this Application have been revised from those filed in the 2003 Mainline Tolls and Tariffs Application, and reflect input from Board staff and representatives of the Canadian Association of Petroleum Producers (CAPP).

In its letter of November 13, 2003, the Board acknowledged the results of the discussions between TransCanada, Board Staff and CAPP.

The OM&A cost section has been expanded significantly from the 2003 Mainline Tolls and Tariffs Application to provide the Board and intervenors with greater clarity of Mainline OM&A costs. Actual 2003 costs include all costs incurred on behalf of the Mainline including costs disallowed in the RH-1-2002 Decision.

OM&A costs are managed by TransCanada on a functional basis and Schedule 13.0 provides an overview of OM&A costs presented in this manner. Additional schedules, 13.1 to 13.8, are provided for detailed costs in each of the functional areas. Furthermore, Tab 13 - Explanatory provides descriptions of each functional area together with explanations of key variances.

OM&A costs in this section are allocated in accordance with the Operating Cost Allocation Policy. A copy of this policy is included as Appendix A to this Section. Appendix A also includes a number of supplementary schedules comparing Mainline OM&A costs with the Alberta System, the B.C. System, as well as TransCanada's other businesses.

These schedules are provided as supplemental information to illustrate application of the Operating Cost Allocation Policy as well as comparisons between lines of business.

Appendix B to this Section includes information on the cost budget process used to develop Test year forecasts.

2.0 Six Year Cost Performance

In 1998, the year of the merger between TransCanada and NOVA Corporation, OM&A costs on the TransCanada Mainline System (Mainline) were $241.2 million. Average gas plant in service was $10.7 billion, and there were over 1,400 employees performing work for the Mainline.

In 2004, six years after the merger, OM&A costs (excluding severance amortizations relating to prior years) are forecast to be $212.3 million, 12% lower than actual 1998 costs. When the effects of inflation are considered, the decline is even more significant. This result is achieved despite considerable increases over this time period in employee compensation as a result of market movements in salaries, incentive compensation, and long term incentive compensation. However, merger synergies and other initiatives have offset inflation, compensation and other increases and have allowed the Mainline to achieve cost reductions. As part of this process, the numbers of allocated Mainline employees are forecast to be below 800 for 2004. This has been achieved despite a 16% increase in gross gas plant in service during the same period.

3.0 OM&A Costs: 2002 to 2004

Excluding severance costs related to prior years, TransCanada is requesting the inclusion of approximately $212 million of OM&A costs in the 2004 revenue requirement. This amount represents an approximate $1 million decrease compared with actual 2003 costs, and a 7.6% increase, excluding inflation, over the 2002 base year amount.

The increase in 2003 relative to 2002 is primarily attributable to higher total direct compensation and benefits. The increases in total direct compensation were necessary to ensure employee compensation was market competitive and to enable TransCanada to attract, motivate, and retain skilled, experienced employees. The increase was also due to severance costs, not subject to the Mainline Service and Pricing Settlement, included in OM&A costs in 2003 but not included in OM&A costs in 2002.

The decrease in 2004 from 2003 is largely due to anticipated reductions in compressor repair and overhaul, and information systems costs. In 2004, there are also forecast increases in total direct compensation, but these have been largely offset by improved operational efficiencies that are expected to reduce the total number of average full-time equivalents (FTEs) allocated to the Mainline from 817 in 2003 to 790 forecasted for 2004.

Costs in 2004 include an estimated salary increase of 3.75% for fixed rate field employees and 5% for other salaried employees. These increases are expected to be implemented on April 1, 2004.

The standard benefit rate (as a percentage of salary) increases from 29% in 2003 to 34% in 2004. This change was primarily made to reflect the results of an actuarial assessment of TransCanada's pension plan dated January, 2003. This change affects costs at the department level but not total OM&A due to an offsetting decrease in the Pension and Benefit Adjustment cost in General

Expenses (see Line 15, Schedule 13.8 and Pension and Benefit Adjustment (Line 23) on page 29 of 31 of this explanatory).

In addition to the changes noted above, an updated actuarial assessment was completed in January 2004, and this has resulted in an overall increase in OM&A costs. The effect of this increase has been included as the 2004 Pension and Benefit Adjustment amount (Line 15, Schedule 13.8).

3.1 Field Operations *(Schedule 13.1)*

Field Operations is organized geographically into three regions and provides on-site operations and maintenance functions for the Mainline high pressure natural gas pipeline system, including valve sites and measurement and compression facilities. Field Operations also includes the costs of aerial line patrol.

Field Operations responsibilities include:

- Interaction with landowners, communities and customers on all aspects of pipeline facility operation and maintenance;
- Pipeline and right-of-way maintenance, including valve maintenance, brush control in forested areas, and maintenance of corrosion prevention systems;
- Gas handling, including pipeline isolation, depressurization and purge and pressure procedures for pipeline inspection, repair and new facility tie-ins;
- Maintenance and calibration of measurement and gas quality monitoring equipment;
- Maintenance of compression facilities, including all major components, electrical and control systems and auxiliary equipment;

- The provision of 24x7 response capability for system alarms, upsets or operational emergencies; and
- Certain cost recovery activities including Right of Way services.

Patrol Aviation includes OM&A costs for flights to survey the pipeline right of way. Regular patrols identify situations that could impact pipeline operations such as leaks, unauthorized crossings, geotechnical concerns, unwanted vegetation and damaged pipeline markers or fences.

Total Field Operations OM&A costs for 2003 were $28.0 million compared to $33.2 million for the 2002 base year, reflecting a decrease of $5.2 million. The primary driver of this cost reduction is efficiency gains in operating practices and procedures, evidenced by a 8% reduction in allocated field employees to the Mainline. The decreased cost also results from a delay in cost recoveries from the 2002 base year to 2003 Actual ($1.7 million).

Total Field Operations OM&A costs for the 2004 test year are $30.6 million compared with $28.0 million in 2003. This $2.6 million increase is primarily due to anticipated salary increases ($0.4 million), the increase in the standard benefit rate ($0.7 million) and a decrease in expected cost recoveries (being an increase in net operating costs) compared to 2003 Actual ($1.6 million.~~)~~.

3.2 **Engineering** *(Schedule 13.2)*

Engineering is responsible for the design, planning and construction of compression, pipeline and measurement facilities including data acquisition and control systems.

As well, Engineering develops integrity plans for all Mainline facilities to ensure optimal system safety, reliability and efficiency at the lowest life-cycle cost.

Major functional areas in Engineering, and related OM&A costs, are outlined in Schedule 13.2. Plant Engineering includes OM&A costs for all Engineering activities related to compressor stations and metering stations. Pipe Engineering includes the OM&A costs for all Engineering activities related to pipeline and associated facilities. Engineering Management and Project Controls provide project management and controls for major projects on the Mainline.

Engineering's total OM&A costs for 2003 were $8.0 million compared to $9.7 million for the 2002 base year, reflecting a decrease of $1.7 million. The primary reason for this decrease is a one-time organizational efficiency study of approximately $0.8 million completed during the 2002 base year. This study helped identify and achieve cost savings in both Field Operations and Engineering.

Engineering's total OM&A costs for the 2004 test year are $9.5 million, which is $1.5 million higher than 2003. The increase in 2004 is due primarily to one time operating projects ($0.7 million) as well as the anticipated salary increase and the standard benefit rate increase. The one time operating projects include work required to maintain and improve the Mainline system that do not meet the capitalization criterion. Potential projects for 2004 include plant integrity work, creating common bill of materials, environmental risk assessments and improvements to supervisory control and data acquisition.

Engineering also contributes to cost savings and cost avoidance efforts in other areas, including compressor fleet repair and overhaul, pipeline integrity, capital expenditures and Field Operations maintenance plans.

3.3 Operations and Engineering Support Services *(Schedule 13.3)*

Business Management Services *(Line 1)*

Business Management Services provides the development, maintenance and support of business processes for Field Operations and Engineering. This includes the following functions: budgeting and forecasting; performance measurement and benchmarking; management and support of computerized maintenance and procurement systems; supplier analysis and qualification; technology management (research and development); accounts payable; contracts administration; vehicle fleet management; and business records management.

The 2003 Business Management Services costs were $5.4 million compared with $5.3 million for the 2002 base year, reflecting an increase of $0.1 million. The 2004 test year costs are $6.8 million, reflecting an increase of $1.4 million over 2003.

The increase in 2003 compared to 2002 is partially due to an organizational change in 2003 which resulted in freight and courier charges being included in Business Management Services in mid 2003. Previously, these costs were included in Field Services and Building Services and totaled $1.2 million in 2002. This increase is partially offset by fewer technology management projects, organizational efficiencies, and cost savings from outsourcing activities.

The increase in the 2004 test year reflects the anticipated salary and standard benefit rate increases together with a full year of freight and courier charges.

Procurement Services *(Line 2)*

Procurement Services sources materials and services for the Mainline. Procurement Services utilizes its knowledge of supply chain management and the leverage potential of the larger TransCanada organization to reduce the material and service costs for the Mainline. Developing long term relationships and alliances with outside service providers for strategic procurement of materials and services ensures longer term value.

Actual 2003 costs for this area were $3.8 million, approximately the same as actual 2002 costs. The 2004 test year costs are forecast to be $2.8 million, representing a $1.0 million reduction compared with 2003.

The 2004 reduction is attributable to organizational adjustments and re-negotiation of contract management fees related to outsource providers. Additionally, implementation of large national contracts to provide a suite of goods and services near Field Operations locations has resulted in a requirement for fewer employees for the procurement of materials and services. These staff reductions offset the anticipated salary and the standard benefit rate increases.

Field Services *(Line 3)*

Field Services provides laboratory analysis services, specialized construction services, warehousing, inventory management and equipment repairs through the following groups:

Lab Services provides analysis of gas samples to determine gas composition and quality, and analysis of engine oil samples for input to the compressor fleet maintenance program. Construction Services maintains a minimum core staff with multiple competencies to provide activities including fabrication of piping assemblies, installation of pipeline branch connections, hydrostatic testing and pipeline dig activities. Warehousing and Inventory Management ensures the correct materials are available for the Mainline when required and that inventory levels are appropriate given the requirements of the system. Equipment Repairs provides specialized shop, field services and technical support for high-value critical compression equipment including gas turbines, aero assemblies, dry gas seals and ancillary equipment.

Construction Services and Equipment Repairs provide the Mainline with some leverage when negotiating external contracts for similar services and provide a degree of assurance that critical services are available when needed. However, TransCanada regularly reviews the services provided to establish whether in-house services continue to add value relative to external providers. For example, TransCanada recently ceased operation of its internal materials testing labs in favour of outsourced alternatives.

Actual 2003 costs for this area were $2.8 million compared with $3.0 million in the 2002 base year, reflecting a~~n~~ decrease of $0.2 million. This variance represents the net effect of increased project work and cost reductions attributable to organizational change.

The 2004 test year costs are forecast to increase by approximately $1.3 million to $4.1 million relative to 2003 costs. This is partially due to an increase of $0.5 million in inventory management costs related to ongoing adjustments to inventory levels as required after the completion of the Inventory Management Program (refer to Schedule 8.0). Approximately $0.6 million of the increase is also related to the full year impact of the organizational changes made in 2003.

Community, Safety and Environment *(Line 4)*

Community, Safety and Environment develops and implements policies and procedures used to promote the safe operation of the Mainline, environmental due diligence and sustained community relationships. As well, Community, Safety and Environment works to ensure applicable safety and environment compliance requirements are understood and adhered to by all employees.

TransCanada's community efforts are aimed at increasing awareness and understanding of existing facilities, which in turn positively contribute to the safety of the public, landowners, employees and facilities. Safety efforts focus on ensuring that employees have the right training to properly complete their tasks.

Environmental efforts include the coordination and execution of environmental planning, environmental inspection, climate change initiatives, reclamation, remediation and vegetation/brush management.

Costs in 2003 for this area were $2.9 million, reflecting a decrease of $0.1 million from the 2002 base year. Test year costs in 2004 are estimated to be $2.2 million, reflecting a decrease of $0.7 million from 2003.

The decrease in costs in 2004 compared with 2003 is primarily attributable to staff reductions and a reduction in program development activities during the 2004 Test year.

3.4 Operations and Engineering Programs *(Schedule 13.4)*

Compressor Fleet Repair and Overhaul *(Line 1)*

The Compressor Fleet Repair and Overhaul program includes OM&A costs associated with the maintenance of compressor units and related systems. Maintenance programs are risk-based in order to optimize maintenance activities for major compression equipment. This approach utilizes detailed maintenance costs, wear rates, failure risk and failure consequence information to determine optimum maintenance intervals and activities.

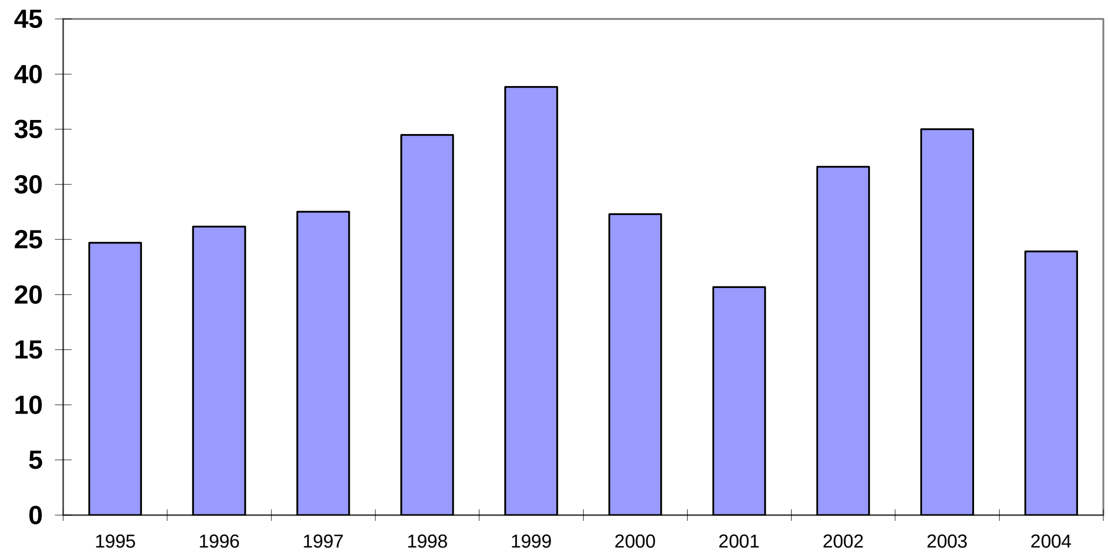
The typical maintenance cycle of a compressor unit includes on-site inspections, minor overhauls, and major overhauls. The overhaul of more specialized equipment, such as gas generators and some power turbines, is completed at specialized repair shops. Overhauls of reciprocating units, centrifugal compressors, and most of the large power turbines are typically carried out on-site, although some components are removed and taken to repair shops for refurbishment.

The Compressor Fleet Repair and Overhaul program includes an estimate of how many overhauls will be required in a given year and the scope of work for each overhaul. The annual overhaul plan is based on a number of factors including: estimates of unit utilization based on flow forecasts; outage impact; operating time since installation, last overhaul, or repair; bundling of maintenance activities; manufacturer service bulletins; availability of spares to support equipment change-outs; and equipment condition. These factors contribute to the cyclical nature of the program costs shown in Figure 3.4-1.

Figure 3.4-1

Canadian Mainline Repair and Overhaul Historical Operating Costs

($ millions)



Overhauls are triggered when one or more of the following conditions are met: the unit accumulates sufficient hours since the last overhaul or repair; equipment fails and it is economical to perform an upcoming overhaul during the repair; other scheduled maintenance is to be performed and it is economical to complete an upcoming overhaul during the same time window; the manufacturer issues a service bulletin that requires immediate action; or operating or integrity problems are identified.

When an overhaul is triggered, the actual timing of the performance of the work may be advanced or delayed slightly by the following factors: bundling work to optimize down time and cost; operating conditions where downtime may impact system deliveries; repair shop constraints (loading, capacity, and spare parts); and availability of spare equipment.

The cost of performing overhauls depends on the complexity of the equipment. Lower-powered industrial gas generators are the least expensive to overhaul while the latest generation of high thermal efficiency, low emissions, aero-derivative gas generators are the most expensive. Low emission units are up to 41% more expensive to maintain than similar conventional gas generators.

Costs in 2003 were $35.0 million compared with $31.6 million incurred in 2002. The $3.4 million increase is due to completion of 29 major and minor overhauls in 2003 compared with 25 in 2002.

Costs in 2004 are estimated at $23.9 million, reflecting a decrease of $11.1 million relative to 2003. This decrease is attributable to completion of:

- 6 major overhauls in 2004 compared with 13 in 2003;
- 9 minor overhauls in 2004 compared with 16 in 2003.

Electric Utilities *(Line 2)*

Electric Utility costs consist of the supply and delivery of electricity to all Canadian Mainline System field facilities, other than that used for electric-driven compressors, which is included in Sales Tax on Fuel and Electric Costs (see Tab 9).

The 2003 costs were $5.1 million ~~as~~ compared with $4.6 million in the 2002 base year, reflecting an increase of $0.5 million. The 2004 test year costs are forecast to increase to $5.4 million, an increase of approximately $0.3 million relative to 2003. The increases in both 2003 and 2004 are primarily driven by higher market prices.

Land Payments *(Line 3)*

Land Payments consist of pipeline right-of-way costs, including lease and access payments for above ground facilities, pipeline easement costs and road access costs. Land payment costs were $0.7 million in 2003 compared with $0.3 million in 2002. The 2004 test year costs are forecast to be $0.6 million. These costs fluctuate from year to year based on the number of renewals in a given year.

3.5 Commercial and Regulatory *(Schedule 13.5)*

Sales, Market Development and Rates *(Line 1)*

The main focus of these groups is to retain and expand the contractual underpinning and discretionary volumes moved by shippers on the Mainline. Increased throughput benefits all shippers by lowering the unit cost of delivery.

The Sales area customer account managers are responsible for individual customer relationships in three key areas: identifying and evaluating opportunities to attach new markets; the development and execution of contracts; and customer service issue resolution. Associated with this function is a communications group, which is responsible for ongoing customer communications such as electronic newsletters, presentations at industry conferences, organization of special customer events and meetings, and the coordination of an annual customer survey.

The Market Development and Rates groups develop rate designs and forecasts and are responsible for developing and obtaining stakeholder support for specific services that will allow both TransCanada and its customers to be successful in the current and future competitive environment. This responsibility involves liaison between industry and TransCanada through co-ordination of the Tolls Task Force.

The 2003 costs for Sales, Market Development and Rates were $4.2 million, up $0.3 million from 2002. This increase is due to the transfer mid year of the Rates department from Regulatory Services into this group together with increased salaries. The 2004 costs are forecast to be $5.3 million, an increase of $1.1

million from costs in 2003. The increase in 2004 is due primarily to the anticipated salary and standard benefit rate increases, the full-year impact of transferring the Rates group from Regulatory Services, as well as increased marketing activities in Eastern Canada and the North-Eastern market of the United States which relate to the Mainline.

System Design and Operations *(Line 2)*

The System Design and Operations departments are responsible for hydraulic analysis, system design, and the safe and efficient operation of the integrated gas transmission system. This group also includes departments responsible for volume forecasting, gas quality, operations planning, and gas control. The key activities performed include receipt and delivery forecasting, facility planning, gas quality tariff management, daily operations planning and capacity management, and the 24x7 control of the gas transmission system.

In order to provide the most economical and long term orderly expansion of the system, the facility planning process incorporates firm transportation requirements, customer requests for service, future volume forecasts, as well as trends in facility utilization to meet those transportation requirements.

The Gas Quality group in System Design and Operations maintains the specifications included in the tariff, and works with Field Operations and Engineering to resolve operational issues associated with the quality of gas received and delivered.

Operations Planning in System Design and Operations deals with the current gas year, primarily day-to-day capacity planning and the selection of operating strategies that minimize fuel usage and operating costs.

Gas Control in System Design and Operations executes a daily operational plan and anticipates and responds to system delivery problems resulting from scheduled and unscheduled outages. Gas Control provides 24x7 control and monitoring, dispatching field technicians when SCADA alarms indicate a need, and managing system flows with upstream and downstream connecting operators.

The 2003 costs for System Design and Operations were slightly lower than 2002 at $4.5 million. In 2004, costs are estimated to increase by $0.6 million to $5.1 million. This increase is largely attributable to the anticipated salary and standard benefit rate increases.

Customer Service *(Line 3)*

The Customer Service area consists of two groups: Contract and Billing, and Nominations and Allocations.

The Contract and Billing group prepares and coordinates transportation contracts, contract transactions (assignments, amendments, etc), economic evaluations, customer billing and all of the associated information systems support.

The Nominations and Allocations group facilitates the gas accounting processes from nominations, allocations and balancing through to confirmations with interconnecting operators. This group operates a customer call centre on a 7 days/week, 15 hours/day basis. This group also maintains and operates extensive computer systems to help manage transactions electronically and to provide customers with on line reports of their transportation activities. In addition, the Nominations and Allocations group is responsible for maintaining TransCanada's customer web sites.

The customer base includes approximately 115 firm transportation contract holders and 320 active firm transportation contracts. There are a number of additional customers who use interruptible transportation service, short term firm transportation service, hub services or firm transportation via temporary assignment. This group operates a total of ten services, a number of service flexibility features, four nomination cycles per day and manages confirmations with approximately 20 interconnecting operators.

Costs in 2003 for this function were $2.3 million, or $1.~~3~~4 million lower than actual 2002 costs. This decline results from overall efficiencies achieved from providing integrated service to TransCanada's three regulated pipelines. Costs in 2004 are expected to increase $0.1 million to $2.4 million. This represents the net effect of increases in salaries and the standard benefit rate, partially offset by a reduction in the amount allocated to the Mainline.

Regulatory Services *(Line 4)*

The Regulatory Services department is responsible for ensuring applications and other regulatory matters related to the Mainline are filed in an effective and timely manner to provide essential information to both the regulator and customers. Activities associated with this function include:

- Preparation of submissions to the Board respecting tolls and tariff matters;
- Support for all key phases of a hearing process, including responding to information requests, preparing rebuttal evidence, preparing witnesses, and assisting with undertakings, argument, and reply argument;
- Submission of specific facilities applications that provide the final technical design, economics, routing/siting, land, environmental, and other relevant information;
- Monitoring and analyzing regulatory proceedings for pipelines with which the Mainline holds transportations contracts (Transmission by Others) as well as other pipelines in Canada and the United States that transport Canadian gas or could impact the Mainline; and

- Researching and analyzing issues of concern to the Mainline which fall within the scope of regulation.

Regulatory Services costs in 2004 of $1.7 million are expected to remain relatively flat compared with 2002 actual costs. The variances from 2002 to 2003 and 2003 to 2004 also reflect the impact of organizational changes in mid-2003 in which the Rates group moved from Regulatory Services to Sales, Market Developments and Rates; and the Applications and Compliance, Facilities group moved to Regulatory Services from System Design and Operations.

3.6 **Business Services** *(Schedule 13.6)*

Business Services consists of a number of support services functions including: Human Resources, Public Sector Relations, Building Services, Finance, Law and General Counsel, as well as costs related to TransCanada's executive leadership team.

Costs in 2003 for this functional area were $18.7 million, or $2.3 million lower than 2002. Costs in 2004 are expected to increase $2.2 million over 2003 actual levels. This increase is due primarily to the anticipated salary and standard benefit rate increases that affect each Business Services support service area in 2004. These increases are expected to be partially offset by organizational efficiencies, lower Building Services costs attributable to lower staff levels, and the consolidation of courier costs with freight costs to Business Management Services in 2003.

Human Resources *(Line 1)*

The Human Resources departments are responsible for providing services and programs, which are designed to attract, retain, and motivate quality employees.

Human Resources provides or assists the organization with day-to-day operational tasks including: employee recruiting and separation; payroll;

compensation delivery; pension and benefits delivery; employee records management; performance management; disability management; and employee/labour relations. Longer-term programs include: organizational design and effectiveness; succession planning and career development; leadership development; and resource planning and forecasting. Changes in these costs during the three year period are due primarily to increases in salaries and the standard benefit rate as well as changes in the portion allocated to the Mainline.

Public Sector Relations *(Line 2)*

The Public Sector Relations function encompasses the communications, community investment and government relations functions.

The Communications group develops and manages communication materials and plans to ensure consistency in messages to internal and external stakeholders.

The Community Investment group develops partnerships with not-for-profit organizations in communities where the Mainline conducts business. Community Investment provides financial support, shares resources (such as contributions of employee time and expertise), and gives gifts in-kind.

The Government Relations group actively participates with all levels of government to acquire information and to constructively influence the development of policies, regulations and legislation. Government Relations helps build relations with key decision makers in the federal, provincial, and local governments, working through a large variety of departments which include natural resources, energy, environment and economic development.

Changes in these costs during the three year period are due primarily to increases in salaries and the standard benefit rate. Costs in 2004 also reflect the addition of new staff involved in communications activities.

Building Services (Line 3)

Building Services provides building/tenant, printing and office services to the organization. These services include: coordination of moves and tenant services; space management, planning and design; construction and project management; reprographic services; office supplies; and internal mail services. These services are performed primarily in the TransCanada Tower.

Costs in this area are expected to decline by $1.5 million or 42% during the period 2002 to 2004 due to lower staff levels and the consolidation of courier costs with freight costs to Business Management Services in 2003.

Finance *(Line 4)*

The Finance functional area includes accounting, risk management, taxation, treasury, and investor relations. It also includes the strategy and planning department which is responsible for developing natural gas supply forecasts and economic forecasts used for system design and pipe project economics.

Finance costs in 2004 are approximately 10% higher than 2003, but only 2% higher than actual 2002 costs. Mainline costs in this area are affected primarily by changes in salaries and benefits as well as changes in the portion allocated to the Mainline.

Law and General Counsel *(Line 5)*

This area includes legal services, internal audit and security.

The Legal group provides timely support on legal issues. Dedicated in house counsels are knowledgeable about the Mainline. In providing these services, legal counsel are assigned to specific functional areas, and retain external counsel as required.

The Internal Audit department operates as an independent, objective, assurance function reporting to the Board of Directors through the Audit and Risk Management Committee. Internal Audit reviews departments and functional areas at appropriate intervals to evaluate whether they are functioning effectively in accordance with laws, regulations, policies and procedures. It evaluates the adequacy and effectiveness of the internal control structure and promotes effective control at a reasonable cost. Internal audit also evaluates the appropriateness of risk mitigation.

Security Services provides general protection to Mainline facilities and employees through physical security, development of policies, as well as communication of security issues to employees. Other services include crisis management and investigation of security related matters.

Law and General Counsel costs applicable to the Mainline are 17% higher in 2004 than in 2003, although the increase is only 9% over the two year period from 2002-2004.

Cost increases in this area are driven primarily by changes in salaries and benefits. The portion attributable to the Mainline will fluctuate depending on the number of active files and the level of support required on each file.

Other (Line 6)

Costs in this area are primarily comprised of salary and benefit costs of the executive leadership team and the expenses of the president and chief executive officer, as well as operating costs of the corporate aviation department. Fluctuations in this account vary primarily on the activities of the executive leadership team. Costs in 2004 also reflect the full year impact of a mid 2003 increase in salary and benefits cost due to an additional executive to this department.

3.7 Information Systems *(Schedule 13.7)*

The Information Systems departments (IS) enable the Mainline's business processes through the provision of information systems solutions including: business applications (purchased or developed); infrastructure to support applications and other services (servers, databases, etc.); desktop computers and common productivity tools; voice and data networks and equipment; collaboration tools such as file-sharing, email and meeting scheduling; and information asset protection (security, backup and recovery, etc.).

A breakdown of IS costs is provided on Schedule 13.7. Overall, 2004 OM&A costs are forecast to be 15% lower than costs in 2002, and 11% lower than actual 2003 costs.

Shared Services *(Line 1)*

This functional area includes the provision and support of workstations, collaborative tools, servers, the application development environment, information systems security, technical architecture and planning as well as IS management and administration.

The Mainline's OM&A costs for IS shared services have dropped from $11.8 million in 2002 to $9.0 million in 2003 and remain relatively flat in 2004. The primary cause of these reductions is a change in computing platform strategy that resulted in more than a 50% reduction in mid range servers. This has reduced overall operating, maintenance and support costs for the server infrastructure. Also contributing to the reduction is a transition to primarily in house resources from an outsourced, shared services model. The costs captured in 2002 under the shared services functional area included about $0.7 million in small projects, while similar projects are managed within the Systems Development category for 2003 and 2004.

Customer and Pipeline Systems Support *(Line 2)*

This functional area provides computer applications and supporting services used specifically by Mainline customer and pipeline business areas and their external customers. The work activities include: requirements gathering, analysis and recommendations; operation of systems, monitoring and system administration; user training and support; "break-fix" and "sustain" activities ("bug" fixes, minor upgrades, version installs, etc.); and portfolio management and lifecycle planning.

The primary functional areas and applications supported by this group include: customer systems supporting transportation contracting, nominations and billing, and gas control; engineering and operations systems such as measurement, design and operations functions supporting plant and pipeline facilities; and regulatory and engineering software applications supporting functions such as gas forecasting, engineering services, land, health, safety and environment.

OM&A costs for this area have been reduced from $5.0 million in 2002 to $4.3 million in 2003 and are forecast to be $4.2 million in 2004. The reductions are primarily the result of reliability improvements resulting from enhanced operation monitoring, analysis, and replacement and overhaul of servers supporting these applications.

Commercial Systems Support *(Line 3)*

This functional area provides general business systems applications and supporting services. The work activities are the same as for the Customer and Pipeline Systems Support group, but involve a different set of software applications and required expertise. They include general business systems in areas such as human resources and procurement, as well as financial systems supporting accounting and treasury.

OM&A costs for this function have remained relatively flat from 2002 to 2004 as a result of salary, benefits and inflationary increases being offset by productivity improvements.

Telecommunications *(Line 4)*

Telecommunications costs include equipment and circuit lease costs, tolls charges, and maintenance and repair of all network and voice infrastructure for the purpose of remote monitoring and control of meter stations, compressor stations and mainline valves, as well as the provision of mobile radio and all voice services.

The costs in this area have decreased from $5.1 million in 2002 to a forecast of $2.7 million in 2004. This reduction is attributable primarily to the use of improved technologies including the replacement of a mobile radio system, and operational efficiencies including a reduction in communication lines at various sites.

Systems Development *(Line 5)*

System Development costs includes the costs of development and enhancement of operating projects for Shared Services, Customer and Pipeline Systems Support, and Commercial Systems Support. Included in these activities are: requirements gathering, analysis and recommendations; alternatives selection including acquisition of vendor-supplied solutions; customization or in-house development; acquisition or development activities; and implementation including data conversion, testing, training and integration with other systems.

This category is new in 2003 as there was an increasing need to manage smaller development and enhancement projects within OM&A costs. This was driven by the need to enhance new software applications delivered in recent years, the need to keep legacy applications current during development of replacement systems and an increased list of smaller new development projects once the large applications were delivered. Prior to 2003, the majority of development work was on large system initiatives that were part of the capital program. Approximately $0.7 million was spent on expensed projects in 2002 but these costs were captured under Shared Services. Systems Development costs are expected to decrease from $3.4 million in 2003 to $2.3 million in 2004 as fewer projects impacting the Mainline are currently planned.

Overall, 2003 IS OM&A costs were $1.3 million lower than costs in 2002, due primarily to changes in the outsourcing model, server rationalization and other productivity improvements. Costs in 2004 are estimated to drop another $2.6 million from 2003 due to a change in telecommunications technology, continued server rationalization and other productivity improvements. Productivity improvements and restructuring activities such as the change in outsourcing model and further organizational design initiatives have resulted in a reduction in labor costs for combined permanent and contracted staff from $16 million in 2002 to $14 million in 2004.

3.8 General Expenses *(Schedule 13.8)*

General Expenses include costs such as rent, insurance, legal and auditing expenses, severance, short and long term incentive compensation and certain benefit costs.

Auditing *(Line 1)*

Auditing fees are amounts paid to external auditors associated with the audit work performed on financial records, due diligence on the financial statements, and accounting advice. The increase in costs in 2004 compared with 2003 of approximately $0.2 million is primarily attributable to additional corporate governance requirements and reviews required by the Sarbanes-Oxley Act.

Legal *(Line 2)*

This account represents expenditures for third party legal fees attributable to the operation of the Mainline, such as litigation and compliance. The increase in costs in 2004 compared to 2003 of approximately $0.4 million is a result primarily of anticipated litigation costs on existing files directly associated with the Mainline and other general corporate matters relating to finance, corporate secretary and employment. External legal fees related to regulatory proceedings of the Mainline have been included in the Regulatory Hearing Costs discussed in Section 16.

Insurance *(Line 3)*

These costs include primarily property and liability coverage for the Mainline. Insurance costs for 2003 are $5.1 million, $0.6 million higher than 2002 because premiums paid in 2002 for 2002/2003 insurance coverage increased significantly due primarily to market conditions. Liability insurance premiums remained relatively flat for 2003 due to a favorable exchange rate that helped to offset higher US dollar denominated premiums. Insurance costs in 2004 are estimated to be $5.9 million, an increase of $0.8 million compared to 2003. This increase is due to tight market conditions for liability coverage that are expected to continue throughout the 2004 premium renewal period.

Stock and Debt Administration (*Line 4)*

Stock and Debt Administration includes such costs as: transfer agent fees; trustee and rating agency fees; line of credit standby fees; annual report costs; and annual meeting costs.

Stock and Debt Administration costs increased from $2.5 million in 2002 to $3.3 million in 2003. This increase is due primarily to higher common stock expenses such as transfer agent and stock exchange fees, higher printing and mailing costs associated with the Annual General Meeting and the costs for a new credit facility established at the end of 2002.

Costs in 2004 are slightly higher than 2003 due primarily to higher common stock expense which includes printing and mailing costs to registered shareholders and annual disclosure matters.

In the RH-1-2002 Decision, the Board disallowed the allocation of line of credit standby fees to the Mainline on the basis that the Mainline was capitalized with a substantial pre-funded position. During the Test Year, the Mainline is forecasting short term funding requirements. For this reason TransCanada submits that maintenance of a stand-by line of credit is prudent for 2004 and therefore the appropriate fees have been allocated to the Mainline.

Incentive Compensation *(Line 5)*

This category represents broad-based annual incentive compensation (IC) payments to employees. A detailed description of IC is provided in Section 14, Compensation and Benefits. Mainline costs for IC increased by $3.9 million to $13.0 million in 2003 compared to $9.1 million in 2002. This increase is partially due to market alignments and to incomplete data gathering for the Incentive Compensation accrual process, resulting in an under-accrual in 2002 which was corrected through higher 2003 IC costs.

The 2004 costs are expected to decrease by $0.8 million to $12.2 million compared with $13.0 million in 2003. The decrease results from a lower overall expense and a reduction in the amount applicable to the Mainline.

Long Term Incentive Compensation *(Line 6)*

Long Term Incentive Compensation (LTIC) represents the costs for restricted share units (RSU), executive share units (ESU), performance unit payments

(PUP) and stock options. A detailed description of LTIC is provided in Section 14, Compensation and Benefits.

Mainline costs for LTIC were $13.1 million in 2003 compared with $8.2 million in 2002. The increase is due primarily to implementation of a share unit program for management and executives (ESU) a revised valuation for RSUs, and higher PUP expense due to an increase in the total number of vested units and related dividends.

LTIC costs in 2004 increase by $2.0 million to $15.1 million. The increase is primarily due to the continued implementation of the share unit program for management and executives ($1.3 million), higher PUP expense resulting from an increase in the number of vested units and related dividends ($0.7 million).

In the RH-1-2002 Decision, the Board disallowed certain LTIC costs. Tab 14, Total Direct Compensation and Benefits, details TransCanada's reasons for inclusion of 100% of LTIC costs in the 2004 Test year OM&A costs.

Dues and Subscriptions *(Line 7)*

Dues and subscriptions consist primarily of memberships in natural gas pipeline industry associations. Costs in 2003 were $0.9 million, $0.1 million higher than 2002. The increase is due primarily to general increases being experienced on fees paid to these organizations. Fee increases are also anticipated in 2004.

Directors' Fees and Expenses *(Line 8)*

This account includes the Mainline share of the remuneration and expenses of TransCanada's Board of Directors. The costs in 2004 are expected to remain at 2003 levels. Overall, the cost fluctuations are not significant compared with 2002.

Donations *(Line 9)*

This account includes donations to support the communities in which the Mainline operates. These donations assist in developing positive relations with the Mainline's stakeholders. The largest donations go to support education, health and human services, and the United Way. Mainline donations of $1.7 million in 2004 are consistent with the average of 2002 and 2003 actual costs. Donations are allocated based on the profit contribution of each of TransCanada's businesses.

Other Regulatory Expenses (Line 10)

This account includes miscellaneous costs such as the costs related to the Tolls Task Force, and the monitoring of or participation in OEB proceedings. These costs declined in 2003 due to a reduced level of activity. Costs are expected to increase by $0.3 million in 2004 to $0.5 million due to increased costs relating to the regulatory business model evaluation.

Relocation Expense *(Line 11)*

Relocation costs represent the costs of moving employees between locations. The decline of costs from $1.1 million in 2003 to $0.9 million in 2004 reflects an overall reduction in relocation activity as well as a decline in the proportion attributable to the Mainline.

Severance (Line 12)

Mainline costs for severance decrease by $2.9 million to $6.0 million in 2004 when compared to $8.9 million in 2003. The amounts have been determined based on the anticipated level of employment terminations in 2004. Severance costs in 2002 were deferred and amortized under the provision of the Mainline Service and Pricing Settlement for 2001 and 2002 (see schedule 13.0). Under the terms of this Settlement, severance costs are deferred and amortized over a three-year period (Schedule 13.0, Line 10). In addition, severance benefits are calculated and shared between TransCanada and shippers on a 70%/30% split, respectively (Schedule 13.0, Lines 12 & 13).

Rent (Line 13)

These costs include rent and operating costs for the company's Calgary office. Rent costs were $8.9 million in 2003, a decrease of $1.4 million compared with 2002. This decline is due to lower net rent and operating expenses and a reduction in the portion attributable to the Mainline. The reduction in rent is primarily due to lower operating costs, including a credit relating to prior year operating costs. Also contributing to the reduction in rent expense is additional sub-tenant revenue and further consolidation to the TransCanada Tower.

Rent costs in 2004 are forecast to be $9.3 million. This represents an increase of $0.4 million from 2003. The increase is due to higher anticipated operating costs in 2004, partially offset by additional sub-tenant revenue.

Other Post Employment Benefits *(Line 14)*

Other Post Employment Benefits (OPEBs) represent the annual amortization of the transitional obligation created as a result of the implementation of the new accounting standard as at January 1, 2000, which effectively changed the accounting treatment of OPEBs from a cash basis to an accrual basis. The transitional obligation is amortized over the expected remaining service life and remains unchanged at $0.9 million each year.

Pension and Benefit Adjustment *(Line 15)*

The Pension and Benefit Adjustment represents the difference between benefits charged to departments at the standard benefit rate and actual benefit costs incurred. The standard benefit rate is determined during the budget process and is based on anticipated overall benefit costs as a percentage of salaries. The increase in 2003 compared with 2002 is due primarily to the January, 2003 actuarial assessment that resulted in higher than expected pension expense in 2003. To adjust for this increase, the 2004 budgeted standard benefit rate was increased to 34% from the 29% rate applied in 2003. However, an updated actuarial assessment was received in January, 2004, indicating that pension expense would increase $2.7 million above the budgeted amount. As a result, the Pension and Benefit Adjustment of $2.7 million was created for 2004.

Actuarial Gain / Loss Amortization *(Line 16)*

This account includes the amortization of actuarial gains and losses on the defined benefit pension plan. Effective January 1, 2003 the defined benefit (DB) plan includes employees previously enrolled in defined contribution (DC) or combination pension plans. In each of 2003 and 2004, this account includes approximately $1.2 million related to this pension plan conversion. In its RH-1-2002 Decision, the Board determined that the actual costs of converting all employees to the defined benefit pension plan should not be borne by shippers, and reduced Mainline 2003 OM&A costs by $3.0 million.

TransCanada understands the following rationale for the Board's decision. Firstly, the Board stated that "…a reasonable company should be expected to decide on one type of plan and stay with that plan." Secondly, the Board said that "for shippers to cover the cost of moving back and forth between plans sets an inappropriate precedent in the event the trend reverses at some point in the future." (Reference RH-1-2002, pp. 21-22.)

TransCanada respectively submits that the determinative question should be whether corporate management has made prudent decisions. TransCanada believes that a reasonable company would not decide on one type of plan and stay with it, whatever the subsequent circumstances may be. TransCanada believes that its management acted reasonably and prudently when it converted its DC plan back to the DB plan. TransCanada management made the decision to convert the DC plan to the DB plan out of regard for the long term strengths of its employee / employer relationship. Considerations included adequate retirement income for long term employees, retention of its skilled and experienced workforce and attraction of new employees. Further, continuation of the DC plan would have become more expensive for toll payers as the contribution rates for the DC plan would have been increased to make the plan competitive. Therefore, it follows that “moving back and forth” would not be inappropriate at all if each decision is reasonable and prudent in the circumstances of the day.

The Mainline actuarial gain / loss amortization increased by $4.0 million to $4.7 million in 2003 compared with $0.7 million in 2002. Actuarial gain / loss costs in 2004 increase by $1.5 million to $6.2 million. This increase is largely due to a change in the discount rate applied in the January, 2004 actuarial assessment.

Miscellaneous Costs (Line 17)

Miscellaneous costs include advertising, public relations, overhead recoveries from third parties and non-regulated capital projects, and various other non-recurring amounts.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Reference	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004	
1	Field Operations	Sched 13.1	33,234	(5,213)	28,021	I	2,540	30,561	
2	Engineering	Sched 13.2	9,746	(1,744)	8,002	I	1,528	9,530	I
3	Operations and Engineering Support Services	Sched 13.3	15,170	(254)	14,916	I	1,013	15,929	
4	Operations and Engineering Programs	Sched 13.4	36,495	4,388	40,883	I	(10,996)	29,887	
5	Commercial and Regulatory	Sched 13.5	13,822	(1,637)	12,185	I	2,306	14,491	I
6	Business Services	Sched 13.6	21,021	(2,308)	18,713	I	2,165	20,878	I
7	Information Systems	Sched 13.7	25,114	(1,274)	23,840	I	(2,565)	21,275	I
8	General Expenses	Sched 13.8	42,735	24,216	66,951	I	2,845	69,796	I
9	Total OM&A Costs Excluding Severance Program Amortization and Benefit [1]		197,337	16,174	213,511	I	(1,164)	212,347	I
	Severance Program - 2001 and 2002 Service and Pricing Settlement								
10	Severance Program Amortization		8,637	(316)	8,321	I	(6,808)	1,513	I
11	Total Before Severance Program Benefits		205,974	15,858	221,832		(7,972)	213,860	I
12	Severance Program Benefits in 2003 and 2004[2]		-	8,964	8,964	I	(6,767)	2,197	I
13	Less: Shipper Share of Severance Program Benefits in 2003 and 2004[2]		-	(2,689)	(2,689)	I	2,030	(659)	I
14	Net TransCanada Benefits		-	6,275	6,275	I	(4,737)	1,538	I
15	TOTAL OM&A COSTS		205,974	22,133	228,107	I	(12,709)	215,398	I

[1] Base Year OM&A costs excludes $3,858 of Regulatory Proceeding Costs now shown as a separate line item in the Revenue Requirement.

[2] Under the Mainline Services and Pricing Settlement, OM&A costs for 2002 was fixed and deemed to include severance benefits.
Consequently, for 2002 the shipper share of benefits was recorded in an incentive Based Deferral Account rather than OM&A costs.

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
FIELD OPERATIONS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004
1	Central Region	14,169	(4,376)	9,793	I	1,427	11,220
2	Northern Ontario	7,636	115	7,751	I	970	8,721
3	Eastern Region	10,403	(944)	9,459	I	47	9,506
4	Patrol Aviation	1,026	(8)	1,018	I	96	1,114
5	Total	33,234	(5,213)	28,021	I	2,540	30,561

I Updated to reflect 2003 actual costs.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
ENGINEERING
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004	
1	Pipe Engineering	2,583	(579)	2,004	I	125	2,129	
2	Plant Engineering	5,906	(875)	5,031	I	1,175	6,206	I
3	Engineering Management and Project Controls	1,257	(290)	967	I	228	1,195	
4	Total	9,746	(1,744)	8,002	I	1,528	9,530	I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
OPERATIONS AND ENGINEERING SUPPORT SERVICES
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004
1	Business Management Services	5,322	131	5,453	I	1,378	6,831
2	Procurement Services	3,847	(75)	3,772	I	(1,009)	2,763
3	Field Services	3,002	(170)	2,832	I	1,266	4,098
4	Community, Safety and Environment	2,999	(140)	2,859	I	(622)	2,237
5	Total	15,170	(254)	14,916	I	1,013	15,929

I Updated to reflect 2003 actual costs.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
OPERATIONS AND ENGINEERING PROGRAMS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004
1	Compressor Fleet Repair and Overhaul	31,582	3,448	35,030	I	(11,099)	23,931
2	Electric Utilities	4,591	534	5,125	I	281	5,406
3	Land Payments	322	406	728	I	(178)	550
4	Total	36,495	4,388	40,883	I	(10,996)	29,887

I Updated to reflect 2003 actual costs.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
COMMERCIAL AND REGULATORY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004	
1	Sales, Market Development and Rates	3,906	254	4,160	I	1,137	5,297	
2	System Design and Operations	4,602	(143)	4,459	I	598	5,057	
3	Customer Service	3,647	(1,382)	2,265	I	169	2,434	I
4	Regulatory Services	1,667	(366)	1,301	I	402	1,703	
5	Total	13,822	(1,637)	12,185	I	2,306	14,491	I

Note: Updated to reflect 2003 actual costs.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
BUSINESS SERVICES
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004	
1	Human Resources	3,188	151	3,339	I	240	3,579	I
2	Public Sector Relations	2,068	(192)	1,876	I	564	2,440	I
3	Building Services	3,702	(1,222)	2,480	I	(316)	2,164	I
4	Finance	7,027	(480)	6,547	I	646	7,193	
5	Law and General Counsel	2,892	(189)	2,703	I	450	3,153	I
6	Other	2,144	(376)	1,768	I	581	2,349	
7	Total	21,021	(2,308)	18,713	I	2,165	20,878	I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

TransCanada
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OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
INFORMATION SYSTEMS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004	
1	Shared Services	11,815	(2,854)	8,961	I	(97)	8,864	I
2	Customer and Pipeline Systems Support	4,971	(707)	4,264	I	(39)	4,225	
3	Commercial Systems Support	3,180	(309)	2,871	I	222	3,093	
4	Telecommunications	5,148	(822)	4,326	I	(1,579)	2,747	I
5	Systems Development	-	3,418	3,418	I	(1,072)	2,346	I
6	Total	25,114	(1,274)	23,840	I	(2,565)	21,275	I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
GENERAL EXPENSES
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

Line No.	Particulars	Base Year 2002	Increase (Decrease)	Actual Year 2003		Increase (Decrease)	Test Year 2004	
1	Auditing	807	38	845	l	158	1,003	
2	Legal	1,584	94	1,678	l	394	2,072	
3	Insurance	4,504	611	5,115	l	754	5,869	
4	Stock and Debt Administration	2,513	772	3,285	l	332	3,617	
5	Incentive Compensation (IC)	9,060	3,947	13,007	l	(853)	12,154	l
6	Long Term Incentive Compensation	8,247	4,872	13,119	l	2,024	15,143	l
7	Dues and Subscriptions	816	102	918	l	165	1,083	
8	Director's Fees and Expenses	610	49	659	l	24	683	
9	Donations	1,770	(210)	1,560	l	119	1,679	
10	Other Regulatory	863	(580)	283	l	259	542	
11	Relocation Expense	1,043	24	1,067	l	(204)	863	l
12	Severance	-	8,894	8,894	l	(2,852)	6,042	l
13	Rent	10,317	(1,451)	8,866	l	471	9,337	l
14	Other Post Employment Benefits (OPEBS)	933	-	933		-	933	
15	Pension and Benefit Adjustment	1,003	3,757	4,760	l	(2,030)	2,730	l
16	Actuarial Gain / Loss Amortization	718	3,994	4,712	l	1,509	6,221	l
17	Miscellaneous	(2,053)	(697)	(2,750)	l	2,575	(175)	
18	Total General Expenses	42,735	24,216	66,951	l	2,845	69,796	l

l Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
TOTAL COMPANY [1]
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
1	Field Operations	33,234	39,214	3,292	549	76,289	
2	Engineering	9,746	12,214	4,610	134	26,704	
3	Operations and Engineering Support Services	15,170	16,913	1,240	2,886	36,209	
4	Operations and Engineering Programs	36,495	24,114	407	-	61,016	
5	Commercial and Regulatory	13,822	16,410	1,678	320	32,230	
6	Business Services	21,021	17,963	1,462	27,199	67,645	
7	Information Systems	25,114	27,863	2,177	12,266	67,420	
8	General Expenses	42,735	45,071	6,403	25,914	120,123	
9	TOTAL OM&A COSTS	197,337	199,762	21,269	69,268	487,636	
10	Percent of Total	40.5%	41.0%	4.3%	14.2%		

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
11	Field Operations	28,021	38,545	2,624	612	69,802	I
12	Engineering	8,002	8,154	2,608	777	19,541	I
13	Operations and Engineering Support Services	14,916	15,905	851	2,332	34,004	I
14	Operations and Engineering Programs	40,883	24,511	341	-	65,735	I
15	Commercial and Regulatory	12,185	15,153	1,758	377	29,473	I
16	Business Services	18,713	16,872	1,364	27,224	64,173	I
17	Information Systems	23,840	25,053	1,650	10,217	60,760	I
18	General Expenses	66,951	53,703	8,563	41,359	170,576	I
19	TOTAL OM&A COSTS	213,511	197,896	19,759	82,898	514,064	I
20	Percent of Total	41.5%	38.5%	3.9%	16.1%		I

		Test Year 2004					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
21	Field Operations	30,561	38,631	2,880	598	72,670	
22	Engineering	9,530	7,480	2,438	2,926	22,374	I
23	Operations and Engineering Support Services	15,929	17,512	861	2,745	37,047	
24	Operations and Engineering Programs	29,887	22,743	349	-	52,979	
25	Commercial and Regulatory	14,491	17,742	1,896	666	34,795	I
26	Business Services	20,878	18,053	1,304	31,943	72,178	I
27	Information Systems	21,275	22,699	1,488	12,170	57,632	I
28	General Expenses	69,796	63,467	8,640	51,190	193,093	I
29	TOTAL OM&A COSTS	212,347	208,327	19,856	102,238	542,768	I
30	Percent of Total	39.1%	38.4%	3.7%	18.8%		I

[1] Total Company OM&A costs include the costs of the Mainline, the Alberta System, the BC System, together with TransCanada's Corporate costs.

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
FIELD OPERATIONS - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
1	Central Region	14,169	8,682	8	549	23,408	
2	Northern Ontario	7,636	-	-	-	7,636	
3	Eastern Region	10,403	-	-	-	10,403	
4	Rocky Mountain Region	-	12,888	3,284	-	16,172	
5	Wildrose Region	-	17,644	-	-	17,644	
6	Patrol Aviation	1,026	-	-	-	1,026	
7	Total	33,234	39,214	3,292	549	76,289	
8	Percent of Total	43.6%	51.4%	4.3%	0.7%		

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
9	Central Region	9,793	6,309	34	612	16,748	l
10	Northern Ontario	7,751	-	-	-	7,751	l
11	Eastern Region	9,459	-	-	-	9,459	l
12	Rocky Mountain Region	-	13,266	2,590	-	15,856	l
13	Wildrose Region	-	18,970	-	-	18,970	l
14	Patrol Aviation	1,018	-	-	-	1,018	l
15	Total	28,021	38,545	2,624	612	69,802	l
16	Percent of Total	40.1%	55.2%	3.8%	0.9%		l

		Test Year 2004				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
17	Central Region	11,220	3,328	247	598	15,393
18	Northern Ontario	8,721	-	-	-	8,721
19	Eastern Region	9,506	-	-	-	9,506
20	Rocky Mountain Region	-	13,847	2,633	-	16,480
21	Wildrose Region	-	21,456	-	-	21,456
22	Patrol Aviation	1,114	-	-	-	1,114
23	Total	30,561	38,631	2,880	598	72,670
24	Percent of Total	42.1%	53.1%	4.0%	0.8%	

l Updated to reflect 2003 actual costs.

TransCanada
In business to deliver

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
ENGINEERING - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
1	Pipe Engineering	2,583	2,464	82	5	5,134
2	Plant Engineering	5,906	7,630	4,058	8	17,602
3	Engineering Management and Project Controls	1,257	2,120	470	121	3,968
4	Total	9,746	12,214	4,610	134	26,704
5	Percent of Total	36.5%	45.7%	17.3%	0.5%	

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
6	Pipe Engineering	2,004	1,741	57	-	3,802	I
7	Plant Engineering	5,031	5,536	2,479	5	13,051	I
8	Engineering Management and Project Controls	967	877	72	772	2,688	I
9	Total	8,002	8,154	2,608	777	19,541	I
10	Percent of Total	40.9%	41.7%	13.4%	4.0%		I

		Test Year 2004					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
11	Pipe Engineering	2,129	2,101	36	-	4,266	
12	Plant Engineering	6,206	4,138	2,304	-	12,648	I
13	Engineering Management and Project Controls	1,195	1,241	98	2,926	5,460	
14	Total	9,530	7,480	2,438	2,926	22,374	I
15	Percent of Total	42.6%	33.4%	10.9%	13.1%		I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
OPERATIONS AND ENGINEERING SUPPORT SERVICES - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
1	Business Management Services	5,322	5,324	171	1,384	12,201
2	Procurement Services	3,847	3,457	160	487	7,951
3	Field Services	3,002	3,794	646	(22)	7,420
4	Community, Safety and Environment	2,999	4,338	263	1,037	8,637
5	Total	15,170	16,913	1,240	2,886	36,209
6	Percent of Total	41.9%	46.7%	3.4%	8.0%	

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
7	Business Management Services	5,453	5,563	303	964	12,283	I
8	Procurement Services	3,772	3,610	164	318	7,864	I
9	Field Services	2,832	3,129	103	197	6,261	I
10	Community, Safety and Environment	2,859	3,603	281	853	7,596	I
11	Total	14,916	15,905	851	2,332	34,004	I
12	Percent of Total	43.9%	46.8%	2.5%	6.8%		I

		Test Year 2004				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
13	Business Management Services	6,831	6,685	405	760	14,681
14	Procurement Services	2,763	2,658	165	535	6,121
15	Field Services	4,098	4,394	70	282	8,844
16	Community, Safety and Environment	2,237	3,775	221	1,168	7,401
17	Total	15,929	17,512	861	2,745	37,047
18	Percent of Total	43.0%	47.3%	2.3%	7.4%	

I Updated to reflect 2003 actual costs.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
OPERATIONS AND ENGINEERING PROGRAMS - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
1	Compressor Fleet Repair and Overhaul	31,582	13,548	-	-	45,130
2	Electric Utilities	4,591	4,443	407	-	9,441
3	Land Payments	322	6,123	-	-	6,445
4	Total	36,495	24,114	407	-	61,016
5	Percent of Total	59.8%	39.5%	0.7%	0.0%	

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
6	Compressor Fleet Repair and Overhaul	35,030	14,196	-	-	49,226	I
7	Electric Utilities	5,125	4,126	327	-	9,578	I
8	Land Payments	728	6,189	14	-	6,931	I
9	Total	40,883	24,511	341	-	65,735	I
10	Percent of Total	62.2%	37.3%	0.5%	0.0%		I

		Test Year 2004				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
11	Compressor Fleet Repair and Overhaul	23,931	10,359	-	-	34,290
12	Electric Utilities	5,406	3,766	349	-	9,521
13	Land Payments	550	8,618	-	-	9,168
14	Total	29,887	22,743	349	-	52,979
15	Percent of Total	56.4%	42.9%	0.7%	0.0%	

I Updated to reflect 2003 actual costs.

TransCanada
In business to deliver

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
COMMERCIAL AND REGULATORY - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
1	Sales, Market Development and Rates	3,906	4,193	515	75	8,689	
2	System Design and Operations	4,602	6,615	740	245	12,202	
3	Customer Service	3,647	4,390	369	-	8,406	
4	Regulatory Services	1,667	1,212	54	-	2,933	
5	Total	13,822	16,410	1,678	320	32,230	
6	Percent of Total	42.9%	50.9%	5.2%	1.0%		

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
7	Sales, Market Development and Rates	4,160	4,507	614	227	9,508	I
8	System Design and Operations	4,459	6,298	641	141	11,539	I
9	Customer Service	2,265	2,946	432	-	5,643	I
10	Regulatory Services	1,301	1,402	71	9	2,783	I
11	Total	12,185	15,153	1,758	377	29,473	I
12	Percent of Total	41.3%	51.4%	6.0%	1.3%		I

		Test Year 2004					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
13	Sales, Market Development and Rates	5,297	5,467	723	589	12,076	
14	System Design and Operations	5,057	7,124	599	77	12,857	
15	Customer Service	2,434	3,596	399	-	6,429	I
16	Regulatory Services	1,703	1,555	175	-	3,433	
17	Total	14,491	17,742	1,896	666	34,795	I
18	Percent of Total	41.6%	51.0%	5.5%	1.9%		I

I Updated to reflect 2003 actual costs.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
BUSINESS SERVICES - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
1	Human Resources	3,188	3,447	268	2,126	9,029
2	Public Sector Relations	2,068	1,191	42	674	3,975
3	Building Services	3,702	4,006	313	2,398	10,419
4	Finance	7,027	5,474	565	13,737	26,803
5	Law and General Counsel	2,892	1,977	117	3,604	8,590
6	Other	2,144	1,868	157	4,660	8,829
7	Total	21,021	17,963	1,462	27,199	67,645
8	Percent of Total	31.1%	26.5%	2.2%	40.2%	

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
9	Human Resources	3,339	3,307	243	2,201	9,090	I
10	Public Sector Relations	1,876	1,140	53	800	3,869	I
11	Building Services	2,480	3,987	178	1,584	8,229	I
12	Finance	6,547	5,079	594	13,387	25,607	I
13	Law and General Counsel	2,703	1,890	142	3,821	8,556	I
14	Other	1,768	1,469	154	5,431	8,822	I
15	Total	18,713	16,872	1,364	27,224	64,173	I
16	Percent of Total	29.2%	26.3%	2.1%	42.4%		I

		Test Year 2004					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
17	Human Resources	3,579	3,520	246	2,805	10,150	I
18	Public Sector Relations	2,440	1,445	66	1,057	5,008	I
19	Building Services	2,164	3,623	144	1,675	7,606	I
20	Finance	7,193	5,336	513	16,328	29,370	I
21	Law and General Counsel	3,153	2,088	150	4,602	9,993	I
22	Other	2,349	2,041	185	5,476	10,051	I
23	Total	20,878	18,053	1,304	31,943	72,178	I
24	Percent of Total	28.9%	25.0%	1.8%	44.3%		I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
INFORMATION SYSTEMS - TOTAL COMPANY
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
1	Shared Services	11,815	12,660	1,011	8,664	34,150	
2	Customer and Pipeline Systems Support	4,971	6,352	722	203	12,248	
3	Commercial Systems Support	3,180	2,951	243	2,829	9,203	
4	Telecommunications	5,148	5,900	201	570	11,819	
5	Systems Development	-	-	-	-	-	
6	Total	25,114	27,863	2,177	12,266	67,420	
7	Percent of Total	37.3%	41.3%	3.2%	18.2%		

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
8	Shared Services	8,961	8,835	593	5,680	24,069	I
9	Customer and Pipeline Systems Support	4,264	5,131	441	175	10,011	I
10	Commercial Systems Support	2,871	2,485	245	2,726	8,327	I
11	Telecommunications	4,326	5,328	201	628	10,483	I
12	Systems Development	3,418	3,274	170	1,008	7,870	I
13	Total	23,840	25,053	1,650	10,217	60,760	I
14	Percent of Total	39.3%	41.2%	2.7%	16.8%		I

		Test Year 2004					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
15	Shared Services	8,864	8,868	546	6,126	24,404	I
16	Customer and Pipeline Systems Support	4,225	4,820	384	184	9,613	I
17	Commercial Systems Support	3,093	- 2,770	263	3,328	9,454	
18	Telecommunications	2,747	3,956	136	722	7,561	I
19	Systems Development	2,346	2,285	159	1,810	6,600	I
20	Total	21,275	22,699	1,488	12,170	57,632	I
21	Percent of Total	36.9%	39.4%	2.6%	21.1%		I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
TOTAL COMPANY GENERAL EXPENSES
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		Base Year 2002				
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company
1	Auditing	807	465	16	262	1,550
2	Legal	1,584	947	20	548	3,099
3	Insurance	4,504	3,131	439	366	8,440
4	Stock and Debt Administration	2,513	1,660	47	767	4,987
5	Incentive Compensation (IC)	9,060	9,755	743	7,068	26,626
6	Long Term Incentive Compensation	8,247	8,888	689	5,900	23,724
7	Dues and Subscriptions	816	458	19	295	1,588
8	Director's Fees and Expenses	610	505	44	1,393	2,552
9	Donations	1,770	1,222	36	1,487	4,515
10	Other Regulatory	863	-	3,228	-	4,091
11	Relocation Expense	1,043	1,170	110	345	2,668
12	Rent	10,317	11,168	884	6,155	28,524
13	Other Post Employment Benefits (OPEBS)	933	887	72	-	1,892
14	Pension and Benefit Adjustment	1,003	1,130	166	657	2,956
15	Actuarial Gain / Loss Amortization	718	771	-	573	2,062
16	Miscellaneous	(2,053)	2,914	(110)	98	849
17	Total General Expenses	42,735	45,071	6,403	25,914	120,123
18	Percent of Total	35.6%	37.5%	5.3%	21.6%	

		Actual Year 2003					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
19	Auditing	845	579	21	345	1,790	I
20	Legal	1,678	402	16	404	2,500	I
21	Insurance	5,115	3,258	592	1,148	10,113	I
22	Stock and Debt Administration	3,285	2,055	79	1,320	6,739	I
23	Incentive Compensation (IC)	13,007	13,201	993	9,215	36,416	I
24	Long Term Incentive Compensation	13,119	13,203	992	9,236	36,550	I
25	Dues and Subscriptions	918	526	18	285	1,747	I
26	Director's Fees and Expenses	659	561	57	1,745	3,022	I
27	Donations	1,560	1,017	33	1,935	4,545	I
28	Other Regulatory	283	268	3,646	-	4,197	I
29	Relocation Expense	1,067	930	46	512	2,555	I
30	Severance	8,894	-	662	2,711	12,267	I
31	Rent	8,866	9,312	743	5,445	24,366	I
32	Other Post Employment Benefits (OPEBS)	933	886	72	-	1,891	I
33	Pension and Benefit Adjustment	4,760	4,784	365	3,358	13,267	I
34	Actuarial Gain / Loss Amortization	4,712	4,804	351	3,331	13,198	I
35	Miscellaneous	(2,750)	(2,083)	(123)	369	(4,587)	I
36	Total General Expenses	66,951	53,703	8,563	41,359	170,576	I
37	Percent of Total	39.2%	31.5%	5.0%	24.3%		I

		Test Year 2004					
Line No.	Particulars	Mainline	Alberta System	BC System	Other	Total Company	
38	Auditing	1,003	565	24	408	2,000	
39	Legal	2,072	793	27	1,478	4,370	
40	Insurance	5,869	3,987	655	2,371	12,882	
41	Stock and Debt Administration	3,617	2,038	87	1,471	7,213	
42	Incentive Compensation (IC)	12,154	12,267	872	9,913	35,206	I
43	Long Term Incentive Compensation	15,143	15,283	1,087	12,351	43,864	I
44	Dues and Subscriptions	1,083	609	25	393	2,110	
45	Director's Fees and Expenses	683	593	54	1,542	2,872	
46	Donations	1,679	1,027	40	1,904	4,650	
47	Other Regulatory	542	47	3,852	-	4,441	I
48	Relocation Expense	863	871	62	704	2,500	I
49	Severance	6,042	5,886	409	4,663	17,000	I
50	Rent	9,337	9,782	747	6,862	26,728	I
51	Other Post Employment Benefits (OPEBS)	933	886	72	-	1,891	I
52	Pension and Benefit Adjustment	2,730	2,756	196	2,227	7,909	I
53	Actuarial Gain / Loss Amortization	6,221	6,278	446	5,074	18,019	I
54	Miscellaneous	(175)	(201)	(15)	(171)	(562)	I
55	Total General Expenses	69,796	63,467	8,640	51,190	193,093	I
56	Percent of Total	36.1%	32.9%	4.5%	26.5%		I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($ Millions)

		Base Year 2002			Actual Year 2003			Test Year 2004		
Line No.	Particulars	Mainline	%	Total Company[1]	Mainline	%	Total Company[1]	Mainline	%	Total Company[1]
1	**FIELD OPERATIONS**									
2	Net Salaries[2]	16.9	22.1%	38.1	14.6	20.9%	34.2 I	14.9	20.5%	35.4
3	Benefits	5.5	7.2%	12.2	5.4	7.7%	11.9 I	6.4	8.8%	13.7
4	Employee Expenses	1.6	2.1%	3.3	1.5	2.1%	3.1 I	1.6	2.2%	3.3
5	Contracted Services / Consultant Fees	4.9	6.4%	11.2	4.5	6.4%	10.6 I	3.7	5.1%	8.4
6	Maintenance Parts / Freight / Courier	3.0	3.9%	8.1	3.0	4.3%	8.1 I	3.6	5.0%	8.8
7	Other Expenses	2.4	3.1%	4.9	2.1	3.0%	6.1 I	2.0	2.8%	5.3
8	Amounts Charged to Other Accounts	(1.0)	-1.3%	(1.5)	(3.1)	-4.4%	(4.2) I	(1.6)	-2.2%	(2.2)
		33.3	43.6%	76.3	28.0	40.1%	69.8 I	30.6	42.1%	72.7
9	**ENGINEERING**									
10	Net Salaries[2]	3.9	14.6%	8.8	3.3	16.8%	7.2 I	4.9	21.9%	10.2 I
11	Benefits	1.8	6.7%	5.1	2.3	11.7%	5.1 I	2.5	10.7%	5.8 I
12	Employee Expenses	0.6	2.2%	1.4	0.4	2.0%	0.9 I	0.7	3.1%	1.5
13	Contracted Services / Consultant Fees	3.1	11.6%	10.3	1.6	8.2%	4.1 I	1.0	4.5%	2.8 I
14	Maintenance Parts / Freight / Courier	0.3	1.1%	1.0	0.1	0.5%	1.8 I	0.1	0.4%	1.4
15	Other Expenses	-	0.0%	0.2	0.3	1.5%	0.5 I	0.3	1.8%	0.7 I
16	Amounts Charged to Other Accounts	-	0.0%	(0.1)	-	0.0%	- I	-	0.0%	-
		9.7	36.3%	26.7	8.0	40.8%	19.6 I	9.5	42.4%	22.4 I
17	**OPERATIONS AND ENGINEERING SUPPORT SERVICES**									
18	Net Salaries[2]	5.1	14.1%	11.7	5.4	15.9%	12.4 I	5.1	13.8%	12.8
19	Benefits	2.2	6.1%	5.1	2.7	7.9%	5.5 I	3.3	8.9%	6.9
20	Employee Expenses	0.8	2.2%	1.7	0.7	2.1%	1.6 I	0.9	2.4%	2.1
21	Contracted Services / Consultant Fees	4.5	12.4%	10.1	3.7	10.9%	8.3 I	2.7	7.3%	6.0
22	Maintenance Parts / Freight / Courier	1.4	3.9%	4.2	1.2	3.5%	3.8 I	2.1	5.7%	5.4
23	Other Expenses	1.3	3.6%	3.5	1.2	3.5%	2.5 I	1.8	4.9%	3.8
24	Amounts Charged to Other Accounts	(0.1)	-0.3%	(0.1)	-	0.0%	(0.1) I	-	0.0%	-
		15.2	42.0%	36.2	14.9	43.8%	34.0 I	15.9	43.0%	37.0
25	**OPERATIONS AND ENGINEERING PROGRAMS**									
26	Net Salaries[2]	-	0.0%	0.1	-	0.0%	- I	-	0.0%	-
27	Benefits	-	0.0%	-	-	0.0%	- I	-	0.0%	-
28	Employee Expenses	-	0.0%	-	-	0.0%	- I	-	0.0%	-
29	Contracted Services / Consultant Fees	25.2	41.3%	36.1	15.9	24.2%	22.2 I	7.4	14.0%	11.0
30	Maintenance Parts / Freight / Courier	6.7	11.0%	9.5	19.4	29.5%	27.5 I	16.5	31.1%	23.6
31	Other Expenses	5.1	8.4%	15.9	6.0	9.1%	16.6 I	6.0	11.3%	18.4
32	Amounts Charged to Other Accounts	(0.5)	-0.8%	(0.6)	(0.4)	-0.6%	(0.6) I	-	0.0%	-
		36.5	59.8%	61.0	40.9	62.3%	65.7 I	29.9	56.4%	53.0

(1) Total Company OM&A costs include the costs of the Mainline, the Alberta System, the BC System, and OM&A costs allocated to TransCanada's other lines of business. It does not include the OM&A costs directly incurred by other lines of business.

(2) Net Salaries includes overtime and ancillary, net of amounts charged to construction and other projects.

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($ Millions)

		Base Year 2002			Actual Year 2003			Test Year 2004		
Line No.	Particulars	Mainline	%	Total Company[1]	Mainline	%	Total Company[1]	Mainline	%	Total Company[1]
33	**COMMERCIAL AND REGULATORY**									
34	Net Salaries[2]	8.8	27.3%	20.5	8.8	29.8%	20.8 I	9.3	26.7%	22.7 I
35	Benefits	2.5	7.8%	5.9	2.7	9.2%	6.3 I	3.2	9.2%	8.0 I
36	Employee Expenses	0.7	2.2%	1.6	0.8	2.7%	1.6 I	1.7	4.9%	3.1
37	Contracted Services / Consultant Fees	0.6	1.9%	1.6	0.4	1.4%	1.5 I	0.6	1.7%	1.6
38	Maintenance Parts / Freight / Courier	-	0.0%	-	-	0.0%	- I	-	0.0%	-
39	Other Expenses	1.5	4.7%	3.1	0.2	0.7%	0.4 I	0.5	1.4%	0.8
40	Amounts Charged to Other Accounts	(0.3)	-0.9%	(0.5)	(0.7)	-2.4%	(1.1) I	(0.8)	-2.3%	(1.4)
		13.8	42.9%	32.2	12.2	41.4%	29.5 I	14.5	41.7%	34.8 I
41	**BUSINESS SERVICES**									
42	Net Salaries[2]	9.9	14.6%	34.0	9.5	14.8%	33.2 I	10.3	14.3%	36.5
43	Benefits	2.7	4.0%	9.3	2.7	4.2%	9.5 I	3.4	4.7%	12.4
44	Employee Expenses	1.3	1.9%	4.1	1.5	2.3%	4.4 I	1.9	2.6%	6.4
45	Contracted Services / Consultant Fees	3.7	5.5%	10.5	2.6	4.1%	8.8 I	2.9	4.0%	8.8
46	Maintenance Parts / Freight / Courier	0.5	0.7%	1.3	0.2	0.3%	0.5 I	-	0.0%	0.1
47	Other Expenses	3.0	4.4%	8.7	2.3	3.6%	8.1 I	2.5	3.5%	8.4
48	Amounts Charged to Other Accounts	(0.1)	-0.1%	(0.2)	(0.1)	-0.2%	(0.4) I	(0.1)	-0.1%	(0.4)
		21.0	31.0%	67.7	18.7	29.2%	64.1 I	20.9	28.9%	72.2
49	**INFORMATION SYSTEMS**									
50	Net Salaries[2]	5.4	8.0%	14.8	7.7	12.7%	20.0 I	6.4	11.1%	17.8 I
51	Benefits	2.2	3.3%	6.3	2.4	3.9%	6.4 I	2.7	4.7%	7.2
52	Employee Expenses	0.5	0.7%	1.4	0.7	1.2%	1.9 I	0.6	1.0%	1.5
53	Contracted Services / Consultant Fees	8.3	12.3%	23.4	5.7	9.4%	13.9 I	4.9	8.5%	12.7
54	Maintenance Parts / Freight / Courier	-	0.0%	-	-	0.0%	0.1 I	-	0.0%	-
55	Other Expenses	8.7	12.9%	21.6	7.3	12.0%	18.5 I	6.6	11.5%	18.4
56	Amounts Charged to Other Accounts	-	0.0%	(0.1)	-	0.0%	- I	-	0.0%	-
		25.1	37.2%	67.4	23.8	39.1%	60.8 I	21.2	36.8%	57.6 I
57	**TOTAL FUNCTIONAL AREAS**									
58	Net Salaries[2]	50.0	13.6%	128.0	49.3	14.4%	127.8 I	50.9	14.6%	135.4 I
59	Benefits	16.9	4.6%	43.9	18.2	5.3%	44.7 I	21.5	6.1%	54.0
60	Employee Expenses	5.5	1.5%	13.5	5.6	1.6%	13.5 I	7.4	2.1%	17.9
61	Contracted Services / Consultant Fees	50.3	13.7%	103.2	34.4	10.0%	69.4 I	23.2	6.6%	51.3 I
62	Maintenance Parts / Freight / Courier	11.9	3.2%	24.1	23.9	7.0%	41.8 I	22.3	6.4%	39.3
63	Other Expenses	22.0	6.0%	57.9	19.4	5.6%	52.7 I	19.7	5.7%	55.8 I
64	Amounts Charged to Other Accounts	(2.0)	-0.5%	(3.1)	(4.3)	-1.3%	(6.4) I	(2.5)	-0.7%	(4.0)
		154.6	42.1%	367.5	146.5	42.6%	343.5 I	142.5	40.7%	349.7 I
65	GENERAL EXPENSES	42.7	35.6%	120.1	67.0	39.3%	170.6 I	69.8	36.1%	193.1 I
66	NET OM&A EXPENSES	197.3	40.5%	487.6	213.5	41.5%	514.1 I	212.3	39.1%	542.8 I

[1] Total Company OM&A costs include the costs of the Mainline, the Alberta System, the BC System, and OM&A costs allocated to TransCanada's other lines of business. It does not include the OM&A costs directly incurred by other lines of business.

[2] Net Salaries includes overtime and ancillary, net of amounts charged to construction and other projects.

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

2004 Mainline Tolls and Tariff Application
February 2004 Update

REVENUE REQUIREMENT
TAB 14

TOTAL DIRECT COMPENSATION AND BENEFITS

Overview

Schedule 14.0 shows the average Total Direct Compensation (TDC) and average benefits cost per full-time equivalent (FTE) for the Mainline System for the 2002 Base Year, 2003 Actual Year, and 2004 Test Year. The annual increases reflected in TDC are the result of market movement of salaries, short-term incentive compensation, and long-term incentive compensation. TransCanada must compete with other employers in the marketplace to attract, motivate, and retain the skilled employees required to operate its business in a safe, reliable, and efficient manner, and as a result, follows a policy of providing market competitive TDC and benefits. This has resulted in increased costs as TransCanada adjusts its TDC to remain competitive in the marketplace.

The year over year increases in average base salary shown in Schedule 14.0 are the result of market competitive salary adjustments and are also impacted by the change in the mix of FTEs being allocated from the various functional areas, as shown in Schedule 14.1.

The increase in short-term incentive compensation from 2002 to 2003 is partially due to market alignments and due to incomplete data gathering for the Incentive Compensation accrual process, resulting in an under-accrual. Incentive compensation levels are expected to decline from from $13.0 million in 2003 to $12.2 million in 2004. This decrease is due to a reduction in the overall expense, as well as a decline in the portion allocated to the Mainline.

The change in long-term incentive compensation from 2002 to 2003 is the result of the implementation of a share unit program for management and executives in order to maintain a market competitive position and a revised valuation for RSUs. The expense related to performance unit payments (PUPs) also increased as a result of an increase in the total number of vested units and related dividends.

The increase in long-term incentive compensation from 2003 to 2004 is the result of the continued implementation of the share unit program for management and executives ($1.3 million). In addition, the expense related to PUPs also increased as a result of an increase in the total number of vested units and related dividends ($0.7 million).

The increase in benefit costs from 2002 to 2003 is primarily the result of an adjustment to pension expense based on the impact of a January 2003 actuarial assessment. Benefit costs are expected to increase in 2004 compared to 2003, again as a result of an adjustment to pension expense based on the effect of a January, 2004 actuarial assessment.

Total Direct Compensation

Total Direct Compensation for all employees consists of base salary plus short-term and long-term incentive programs. Short-term and long-term incentives have become standard components of competitive compensation for all levels of employees offered in the energy industry (short-term incentives 99% prevalence, long-term incentives 86% prevalence[1]). TransCanada responds to market trends to remain competitive with companies in the energy industry. Consequently, TransCanada has introduced both short-term and long-term incentive programs. Without these programs TransCanada would be offering employees a TDC package that is less than that offered by other energy industry based companies. This would compromise TransCanada's ability to attract, motivate, and retain the skilled employees required to operate its business in a safe, reliable, and efficient manner. These compensation components are appropriate in the current and foreseeable competitive marketplace but are subject to ongoing revision in order to maintain competitive compensation practices and programs in the future.

TransCanada's TDC programs are in place to attract, motivate, and retain employees with the knowledge and experience required to operate its business in a safe, reliable, and efficient manner. In order to compete for these employees under current economic conditions in Alberta, including the lowest unemployment rates (2002 – 5.3%)[2] and with the highest inflation rate (2002 CPI 3.4% increase)[3] in Canada, TransCanada must provide a competitive TDC package. TransCanada's TDC expenditure levels and components are prudent when compared to industry norms and are necessary to remain competitive against industry compensation levels.

TransCanada assesses the competitiveness of its TDC by comparing it with compensation market survey data from a comparator group, which consists of companies in similar industries of similar size and scope. TransCanada's objective in establishing its TDC target is to be competitive with the median of the comparator group. The median of the comparator group describes the point at which 50% of the sampled values are greater and 50% are lower. TDC for employees performing at sustained fully satisfactory performance levels are aligned with the median compensation level of the comparator group, while sustained performance that exceeds expectations provides the opportunity for employees to receive compensation that surpasses the median.

The table below demonstrates how TransCanada's TDC compares to the median of the comparator group in 2003.

[1] Towers Perrin 2003 Energy industry Briefing, October 23, 2003.
[2] Conference Board of Canada, Provincial Outlook Summer 2003 – Economic Forecast.
[3] Conference Board of Canada, Provincial Outlook Summer 2003 – Economic Forecast.

Table 1
Comparison of TCPL Data to Towers Perrin
Total Rewards Data Base (TRDB) 2003

	1.1 TCPL 2003 data submitted to TRDB	**1.2 Towers Perrin 2003 TCPL comparator group**	**1.3 Variance to Market**
A) Target Total Direct Compensation (for all positions matched to TRDB)	Average $107,560	Median $116,288	-7.5%
B) Actual Total Direct Compensation (for all positions matched to TRDB)	Average $111,566	Median $119,036	-6.3%

- Line A, Target Total Direct Compensation, represents the competitive position that TransCanada wishes to target in the pay market. TransCanada's target for Total Direct Compensation is the median of the market, provided that performance objectives are met or exceeded.

- Line B, Actual Total Direct Compensation, represents the actual 2003 base pay, actual incentive compensation paid in 2003 and the estimated future value of long-term incentives to be paid for the plan year 2003.

- Column 1.1 represents TransCanada's Total Direct Compensation for approximately 1,481 executive, management, professional and administrative employees.

- Column 1.2 represents all of the comparator group's target and actual compensation information for all positions that each company in the comparator group matched into the TRDB. This represents approximately 17,250 employees.

Job Family Data

The table below provides further detail on TransCanada's TDC compared to the comparator group by summarizing TDC by job family. The job families selected are occupations that are reported on a sustainable basis year over year. They also have a sufficient number of incumbents both at TransCanada and in the market surveys to allow for meaningful comparison. These data show that TransCanada's TDC for the majority of these job families was within plus or minus 10% of the market median in 2003, a level that TransCanada considers competitive.

Table 2
Summary of TCPL TDC vs. Comparator Group
TDC by Job Family[4] 2003

Job Family	Average TCPL Actual TDC ($)	Average Market 50th Actual TDC ($)	Variance to Market
Manager to CEO	256,203	242,031	5.9%
Accounting	85,943	86,722	-0.9%
Secretarial, Clerical, Administrative Assistants	53,538	51,250	4.5%
Engineering	107,064	105,103	1.9%
Human Resources	91,266	82,928	10.1%
Information Systems	85,424	83,313	2.5%
Safety and Environment	94,271	95,153	-0.9%
Procurement	85,235	76,108	12.0%

[4] Table reproduced from Towers Perrin report dated December 4, 2003.

Fixed Rate (Field) Positions

Fixed rate (field) positions are positions held by employees who are engaged in the direct operation and maintenance of the pipeline system. They are paid according to a step progression (fixed rate) system based on compensation for similar trades and occupations. A step progression system specifies levels within a pay range. Employees may progress from step to step on the basis of performance, required education, practical application, proficiency in the role, and time-in-grade.

TRDB Data for TDC are not available for these positions. The table below shows TransCanada's actual average base salary for fully qualified and senior field positions as compared to aggregate median union rates for fully qualified field positions. The data on union rates are publicly available from the Human Resources Development Canada database.

Table 3
Fixed Rate (Field) Positions 2003

	TransCanada Actual Pay at Fully Qualified/ Senior Level	Aggregate Median Union Rates Fully Qualified Level Human Resources Development Canada and Towers Perrin	Variance to Market
Base Pay	$32.30 per hour	$31.87 per hour	1.3%

Compensation Surveys and the Comparator Group

TransCanada determines the competitiveness of its TDC by comparing it to compensation market survey data. These surveys are developed, maintained and administered by external compensation consultants. In order to participate in and have access to the results of these surveys, TransCanada agrees, through a signed confidentiality agreement, to maintain the survey data in a confidential manner and to use it only for the purposes of maintaining competitive compensation programs.

The surveys draw information from similar industries and from companies of similar size and scope to TransCanada. Specifically, TransCanada compares its compensation data with the compensation data of a defined competitive compensation market, the comparator group, consisting of companies that are a source of skilled employees for TransCanada or to which TransCanada may lose skilled employees. TransCanada's comparator group consists of approximately 25 companies with the following attributes:

Table 4
Characteristics of TransCanada's Compensation Comparator Group 2003

	TransCanada Information	**Towers Perrin Data – TransCanada's Comparator Group**
Industry	North American Pipelines, Power	Canadian Oil and Gas, Pipelines, Power
Location	Calgary	Principally Alberta
Revenue	$5.2 billion	• Median is $3.7 billion • 75th percentile is $6.1 billion
Market Capitalization	$12.0 billion	• Median is $8.5 billion • 75th percentile is $14.4 billion
Assets	$19.9 billion	• Median is $9.2 billion • 75th percentile is $13.1 billion
Employees	2,350	• Median is 2,663 • 75th percentile is 3,792

Appropriateness of TDC for the Mainline System

The 2004 test year Operating Costs amount includes costs related to each of the components of TDC: base salary, short-term incentive compensation, and long-term incentive compensation. It is appropriate to include these amounts in the revenue requirements because they are in their totality the prudent and legitimate fair market costs directly incurred for the purpose of operating the Mainline System. As such, TransCanada should be provided with the opportunity to recover all these costs in its rates.

TransCanada has found it necessary to offer incentive-based compensation in order to compete effectively in the market for the skilled employees required to operate its business in a safe, reliable, and efficient manner. It has designed the specific incentive plans in use to enhance organizational performance towards specific objectives. In providing services required by its customers, TransCanada has a responsibility to manage costs efficiently and economically. Its performance in this regard in the short and long-term is due to the aggregate efforts of employees. Incentive payments to employees are determined on the basis of performance measured against multiple benchmarks at the individual and company level. The intended result is the existence of a healthy, sustainable pipeline operator that consistently provides safe, reliable service, which is to the benefit of customers and shareholders without distinction. TransCanada employs skilled employees for the benefit of shippers and shareholders alike. It is not reasonably possible to separate the work performed by employees between shippers and shareholders. To adequately compensate employees for performing their jobs, market competitive TDC must be paid.

In the most recent decision[5] by the National Energy Board (NEB), the Board provided its views with respect to TransCanada's TDC. The Board quoted the evidence that the Mainline's total compensation per employee (base salary, short-term and long-term incentives, plus benefits) was in line with the compensation provided by companies of similar size and scope. The Board also accepted that TransCanada, in order to be competitive in the marketplace for employees, must offer a suite of compensation components similar to its comparator group. The

[5] National Energy Board, Reasons for Decision RH-1-2002, TransCanada PipeLines Limited Tolls and Tariff, July 2003, pp.20-21.

Board further stated that focus on shareholder value is not necessarily to the detriment of shipper interests.

However, after giving consideration to its views expressed above, the Board concluded that TransCanada's LTIC clearly rewards employees for aligning their interests with shareholders. As such the Total Shareholder Return (TSR) benchmark used by TransCanada for its long-term incentive programs was singled out as a reason by the Board for disallowing 50% of the costs associated with long-term incentives.

In TransCanada's view there is a contradiction between the found reasonableness of its total compensation per employee and the related disallowance of costs based on this one specific benchmark. TransCanada further suggests that TSR growth reflects the value of a company that has managed its affairs wisely, provides predictable return, and operates efficiently, all factors that benefit customers. The determination should be based on the question at hand: are the proposed total compensation costs per employee prudent, legitimate, and directly related to the provision of service and therefore recoverable in rates? To determine allowed long-term incentive compensation on the basis of the acceptability of one of the benchmarks used to determine payment is perhaps ultimately pointless as the benchmark can be changed. The benchmark is not the relevant issue; the issue is whether the total compensation per employee is appropriate.

Components of TDC

The three components of TDC are base salary, short-term incentive compensation, and long-term incentive compensation.

Base Salary

TransCanada's base salary program is based on two fundamental principles: market competitiveness and individual performance.

TransCanada competes with other organizations to attract and retain employees with the skills necessary to operate in a safe, reliable and efficient manner. To do so, TransCanada offers salaries at competitive levels to the defined competitive compensation market, the comparator group. TransCanada monitors compensation levels in this marketplace and adjusts compensation levels as appropriate to remain competitive.

The following table shows TransCanada's aggregate annual pay increases since 2000 compared to a broad oil and gas industry average over the same period of time.

Table 5
TransCanada's Aggregate Annual Base Salary Increases Compared to Industry Average

Effective Date	TransCanada	Towers Perrin Energy Industry Salary Management Survey
April 1, 2004	Available May 1, 2004	Not available until November 2004
April 1, 2003	3.7%	5.1%
April 1, 2002	4.5%	5.2%
April 1, 2001	5.5%	5.6%
April 1, 2000	4.0%	4.2%

Preliminary projections for 2004 salary adjustments were required to satisfy budgeting requirements. The assumptions used for the annual budget process, and this Application, were based on an increase of 5% for salaried employees and a 3.75% increase for fixed rate employees over 2003 levels. Since market projections were not available at that time, these preliminary projections were largely based on past industry averages and judgment based on knowledge of the competitive marketplace (Table 5).

Current projections from independent credible compensation sources for salary increases in the oil and gas industry are ranging from 3.9% to 4.4%. These sources are used only as background information. TransCanada will make final decisions on salary increases based on all competitive compensation data available at the end of February 2004 and adjustments are implemented effective April 1.

An employee's base salary should also reflect the contribution of that individual to the success of the company. This is achieved by determining increases to base salary on the basis of individual performance. The actual increase to an employee's base salary for each job or position in the company may vary depending on the salary market data for that position and individual performance. The following table shows the distribution of employees across the performance ranges for base salary.

Table 6
2003 Base Salary Performance Distribution
(% of total Employee Population as at April 1, 2003)

	Developing or Newly Promoted	Fully Qualified, Fully Satisfactory	Key Contributors	Exceptional Performers	Total
Field	N/A(1)	25%	N/A(1)	N/A(1)	25%
Non-Field	12%	53%	8%	2%	75%
Total	12%	78%	8%	2%	100%
Management(2)	1%	6%	2%	1%	10%
Non-Mgmt	11%	72%	6%	1%	90%
Total	12%	78%	8%	2%	100%

(1) Fixed Rate Pay - no salary ranges.
(2) Management is defined as the employee level at which there is clear responsibility for management tasks (supervising work, hiring, performance management, etc.), budgeting responsibilities, and decision-making impact on the business.

Short-Term Incentive Compensation Program

The use of short-term incentive compensation allows TransCanada to effectively manage compensation costs in line with actual performance by putting a portion of compensation at risk unless certain objectives tied to individual performance are achieved.

Short-term incentive compensation is a competitive practice both in the energy industry and more broadly in the Canadian industry. According to a recent study[6] of Canadian energy companies:

- Short-term incentives are virtually universal: 99% prevalence
- An overwhelming number of plans are broad based: 88%
- Of the remaining plans, one third include professionals and above

According to a recent study by the Conference Board of Canada[7] the prevalence of annual variable pay in the private sector (in the reporting organizations) is 92%.

TransCanada's Short-Term Incentive Compensation (IC) program is based on individual employee performance. Targets for all employees are set at the median of the defined competitive compensation market for the appropriate function, role and level of work. Individual incentive awards are based on performance against objectives, competencies, behaviors, and results, as well as market data reflecting bonus payments. If results are not achieved, the incentive award is reduced or not paid out. For achievement of outstanding results, there is opportunity for an increased incentive award. This results-oriented assessment method ensures there is a value added in exchange for the incentive award. This value added benefits customers through improved efficiency, safety, and reliability of the pipeline system.

[6] Towers Perrin 2003 Energy Industry Briefing, October 23, 2003.
[7] Conference Board of Canada, Compensation Planning Outlook, 2004.

Long-Term Incentive Programs

TransCanada's long-term incentive plans have evolved to remain competitive with the market, to meet changing business conditions, and to align with and support business strategies.

Market Prevalence of Long-Term Incentive Programs

Long-term incentive programs are most prevalent in the oil and gas industry and well established in Canadian general industry. A study[8] of Canadian-based energy companies noted the following:

- The vast majority of companies have long-term incentives: 86%.
- Over half of the plans are broad based: 54%.
- Of the remaining plans approximately half include professionals/senior technical level employees.

In addition, the Conference Board of Canada[9] disclosed that 55% of organizations have long-term incentives for at least one employee group and that long-term incentive plans continue to be most common among firms that are publicly traded (86%).

Customers benefit from long-term incentives being a component of the TDC package because TransCanada is able to attract and retain over the longer term skilled individuals required to sustain safe, reliable, and efficient operation of the pipeline system. Long-term incentive programs focus employee attention in a way that is beneficial to the organization over a longer period of time by rewarding sustained results.

[8] Towers Perrin 2003 Energy Industry Briefing, October 23, 2003.
[9] Conference Board of Canada, Compensation Planning Outlook, 2004.

Long-term incentives are tied to measures that, in aggregate, reflect sustained, prudent business management, including financial measures, corporate governance, health and safety targets, cost containment, and both regulated and non-regulated business growth. These measures are ultimately reflected in such aggregate measures as Total Shareholder Return (TSR) and stock price. TSR growth reflects the value of a company that has managed its affairs wisely, provides predictable return, and operates efficiently, all factors that also benefit customers. It is common business practice to tie long-term incentive plans to key corporate measures, such as TSR growth or stock price. Through this practice, long-term incentives are not paid out, nor further costs incurred, unless there is additional value generated.

The following information provides a description of TransCanada's long-term incentive programs.

TransCanada Stock Option Plan

TransCanada utilizes a stock option program for executive officers, as well as other select key employees. The size of the annual stock option award to individual executive officers is determined by considering individual performance results, level of responsibility, and the degree to which each executive officer's long-term potential and contribution will be key to the long-term success of TransCanada.

Performance Unit Plan (PUP)

In July 2002, TransCanada discontinued the use of PUPs in its compensation plan; however, accruals on existing units will continue in accordance with the terms of the former plan.

Under the plan, a unit accrues a cash amount annually, which is no greater than the dividends paid on a TransCanada common share for the preceding financial year if

TransCanada's total shareholder return is equal to or greater than that of the peer group index for such financial year.

Executive Share Unit Plan (ESU)

The ESU Plan is part of TransCanada's competitive compensation program for executives. It is a performance driven plan that aligns individual performance with the achievement of TransCanada's objectives and is also intended to retain key executives. Under the ESU Plan executives are eligible for an annual grant, with units vesting after a three-year cycle, provided the pre-determined corporate performance criteria are met. The current three-year cycle is in effect from January 1, 2003, through to December 31, 2005, with the first anticipated share disbursements in the first quarter of 2006.

Restricted Share Unit Plan (RSU)

The RSU Plan is a broad-based employee program that is part of TransCanada's competitive TDC package for employees who are Senior Managers and below. It is aimed at motivating and retaining skilled, experienced employees. The current RSU plan three-year cycle is in effect from January 1, 2002, through to December 31, 2004, with the first anticipated payout in the first quarter of 2005.

Benefits

Employee benefits are offered to employees under a program TransCanada refers to as the FlexComp Benefit Program. The FlexComp Benefit Program offers flexibility and choice in customizing benefits to meet employees' personal needs and lifestyle in a cost effective way. Employees receive FlexComp credits based on a formula applied against annual base salary. Employees receive core benefits to provide a minimal level of coverage and choose to purchase optional benefits with FlexComp credits to meet their individual needs. The various types of benefits offered and the use of the FlexComp Benefit Program have also been designed to be market competitive, thereby, contributing to TransCanada's ability to attract and retain employees. Specific employee benefits offered are:

Health and Dental Plans

The health plans consist of three options with varying coverage. Employees may also opt-out of the dental plan. The health and dental plans are self-insured and administered by a third party.

Group Insurance Plans

Core employee life insurance coverage of $50,000 is company-paid. Employees may purchase optional employee, spousal and per child life insurance. Effective January 1, 2004, employee optional life insurance is limited to 7 times an employee's base pay or $1,500,000, reduced from $2,500,000. Spousal and per child life insurance have limits of $250,000 and $25,000 respectively.

Core employee accident insurance coverage of $50,000 is company paid. Employees may purchase optional employee, spousal and per child accident insurance. Coverage is limited to $1,000,000, $250,000 and $25,000 respectively.

Provincial Health Insurance

In Alberta and British Columbia, the company pays for 80% of the annual premium; employees pay 20%. In other provinces, the company pays the full cost according to provincial regulations (i.e., payroll/health tax).

Short-Term Disability

Coverage is company paid and consists of 100% or 70% of base pay, based upon service, payable for up to 26 weeks.

Long-Term Disability

Coverage is company paid and consists of 70% of base pay, payable to recovery or age 65. The benefit is taxable.

Employee Stock Savings Plan

Employees may purchase shares of TransCanada Corporation by directing optional contributions to an employee and/or spousal RRSP or a taxable account. For participating employees, TransCanada will match the employee directed purchase in an amount equal to 25% of the employee amount to a maximum additional contribution of 1% of the employee's base pay.

Pension Plan

TransCanada provides its employees with a Registered Pension Plan. The plan is a defined benefit plan under which the annual pension plan benefits are integrated with Canada Pension Plan benefits and are based on: 1.25% of a person's highest average pensionable earnings up to the Final Average Year's Maximum Pensionable Earnings; plus 1.75% of a person's highest average pensionable earnings in excess of the Final Average Year's Maximum Pensionable Earnings; multiplied by the total number of years credited in the Registered Pension Plan ("Credited Pensionable Service").

Registered pension plan benefits are subject to a maximum annual benefit accrual provided for by the Income Tax Act (Canada), currently $1,722 for each year of Credited Pensionable Service, with the result that benefits cannot be earned in the Registered Pension Plan on salaries above approximately $110,000 per annum.

Under the Supplemental/Executive Supplemental Pension Plan, employees/executives of TransCanada are entitled to supplementary pension benefits. The annual pension benefit is equal to the amount calculated using a formula of 1.75% multiplied by the employees/executives credited pensionable service under the plan multiplied by the amount by which such employees/executives highest average annual pensionable earnings exceeds such employees/executives highest average annual Registered Pension Plan earnings.

Schedule 14.0 details Total Direct Compensation and Benefits for the years 2002, 2003 and 2004. This includes total company analysis by functional area as well as the allocated Mainline component.

Schedule 14.1 shows Average Full Time Equivalent employees for the years 2002, 2003 and 2004. The analysis is shown for both total company and the Mainline, and is further broken down by functional area.

Schedule 14.2, Net Salaries Analysis, reconciles base salaries on Schedule 14.0 to net salaries on Schedule 13.18.

Schedule 14.3 provides information on the total cost of benefits as well as the allocated Mainline component for 2002, 2003 and 2004.

TOTAL DIRECT COMPENSATION & BENEFITS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($ '000)

		2002			2003			2004		
Line No.	Particulars	Total	Average Full Time Equivalent	Average Salary	Total	Average Full Time Equivalent	Average Salary	Total	Average Full Time Equivalent	Average Salary
	TOTAL COMPANY BASE SALARIES: [1]									
1	Field Operations	43,410	647	67.1	41,039	587	69.9 I	40,306	555	72.6
2	Engineering	18,422	230	80.1	17,644	209	84.5 I	17,105	197	86.8
3	Operations and Engineering Support Services	18,386	258	71.3	19,113	266	71.9 I	20,207	271	74.6
4	Commercial and Regulatory	20,951	264	79.4	21,729	262	83.0 I	23,461	269	87.2
5	Business Services	33,104	364	90.9	32,986	340	97.0 I	36,487	365	100.0
6	Information Systems	22,457	305	73.6	22,033	294	75.0 I	21,253	276	77.0
7	Total Salaries	156,730	2,068	75.8	154,544	1,958	78.9 I	158,819	1,933	82.2
8	Allocated Mainline System Amounts [2]									
9	Base Salary	60,442	814	74.3	62,872	817	76.9 I	63,246	790	80.1 I
10	Incentive Compensation	9,060	814	11.1	13,007	817	15.9 I	12,154	790	15.4 I
11	Long Term Incentive Compensation	8,247	814	10.1	13,119	817	16.0 I	15,143	790	19.2 I
12	**Total Direct Compensation**			**95.5**			**108.8** I			**114.7** I
13	Benefits [3]	17,932	814	22.0	23,004	817	28.1 I	24,238	790	30.7 I
14	Total Direct Compensation and Benefits			117.5			136.9 I			145.4 I

(1) Total Company base salaries costs include the base salaries costs of the Mainline, the Alberta System, the BC System, and base salaries costs allocated to TransCanada's other lines of business. It does not include costs directly incurred by other lines of business.

(2) Based on the Operating Cost Allocation Policy provided in Tab 13 - Appendix A

(3) Excludes amortization of actuarial gains and losses, as well as amortizations of past service costs. (See Schedule 14.3, line 17)

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

STAFF ANALYSIS
AVERAGE FULL TIME EQUIVALENT
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004

		2002			2003				2004			
Line No.	Particulars	Total Company	Allocated Mainline	% of Total	Total Company	Allocated Mainline	% of Total		Total Company	Allocated Mainline	% of Total	
1	Field Operations	647	292	45.1%	587	269	45.8%	I	555	255	45.9%	
2	Engineering	230	83	36.1%	209	95	45.5%	I	197	84	42.6%	I
3	Operations and Engineering Support Services	258	111	43.0%	266	131	49.3%	I	271	132	48.7%	
4	Commercial and Regulatory	264	110	41.7%	262	111	42.4%	I	269	111	41.3%	I
5	Business Services	364	109	29.9%	340	99	29.1%	I	365	105	28.8%	
6	Information Systems	305	109	35.7%	294	112	38.1%	I	276	103	37.3%	
7	TOTAL	2,068	814	39.4%	1,958	817	41.7%	I	1,933	790	40.9%	I
8	Mainline Headcount		814			817		I		790		I
9	Charged to Construction & Other		(167)			(189)		I		(160)		I
10	Net Mainline Headcount to OM&A costs		647			628		I		630		I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

NET SALARIES ANALYSIS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

		2002			
		Total	Mainline	Mainline %	
1	Base salary (Line 7/9, Schedule 14.0)	156,730	60,442	38.6%	
2	Ancillary and Other	13,143	5,540	42.2%	
3	Charged to Construction & Other	(41,911)	(15,897)	37.9%	
4	Net Salaries (Line 58, Schedule 13.18)	127,962	50,085	39.1%	

		2003			
		Total	Mainline	Mainline %	
5	Base salary (Line 7/9, Schedule 14.0)	154,544	62,872	40.7%	I
6	Ancillary and Other	10,263	4,435	43.2%	I
7	Charged to Construction & Other	(37,070)	(18,049)	48.7%	I
8	Net Salaries (Line 58, Schedule 13.18)	127,737	49,258	38.6%	I

		2004			
		Total	Mainline	Mainline %	
9	Base salary (Line 7/9, Schedule 14.0)	158,819	63,246	39.8%	I
10	Ancillary and Other	8,125	3,959	48.7%	I
11	Charged to Construction & Other	(31,590)	(16,260)	51.5%	I
12	Net Salaries (Line 58, Schedule 13.18)	135,354	50,945	37.6%	I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

STAFF ANALYSIS
ALLOCATED EMPLOYEE BENEFIT COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

LINE NO.	PARTICULARS	Base Year 2002	Change	Actual Year 2003		Change	Test Year 2004	
	(a)	(b)		(c)			(d)	
	Total Company Employee Benefits							
1	Pension Plan and Retiree Expenses	20,570	8,995	29,565	I	(2,296)	27,269	
2	Pension and Benefit Plan Administration	2,872	(298)	2,574	I	(456)	2,118	
3	Provincial Health Insurance	1,824	(99)	1,725	I	68	1,793	
4	Employee Insurance and Savings Plan	12,662	481	13,143	I	1,191	14,334	
5	Training and Development	230	(29)	201	I	63	264	
6	Employee Club	205	(13)	192	I	1	193	
7	Worker's Compensation	374	198	572	I	8	580	
8	EI, CPP, QPP	6,684	(586)	6,098	I	239	6,337	
9	Other Benefits	954	(164)	790	I	320	1,110	
10	Total Company Employee Benefits	46,375	8,485	54,860	I	(862)	53,998	
11	Total Base Salaries (Line 7, Schedule 14.0)	156,730		154,544	I		158,819	
12	Effective Benefit Rate	29.6%		35.5%	I		34.0%	
	Allocated Mainline							
13	Base Salaries (Line 9, Schedule 14.0)	60,442		62,872	I		63,246	I
14	Standard Rate	28.0%		29.0%			34.0%	
15	Applied at Standard Rate	16,929		18,244	I		21,508	I
16	Pension and Benefit Adjustment	1,003		4,760	I		2,730	I
17	Total (Line 13, Schedule 14.0)	17,932		23,004	I		24,238	I

I Updated to reflect 2003 actual costs and revised for the 2004 Test year.

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REVENUE REQUIREMENT
TAB 15

DEBT REDEMPTION COSTS/(GAINS)
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($ 000)

Ln. No.	Particulars	
	(a)	(b)
	Redemption of Junior Subordinated Debentures 8.75% due 2045 ($US)	
	Amortization of Debt Issue Expense	
1	Unamortized Balance at December 31, 2002	5,966
2	Amortization to date of redemption (July 3, 2003)	(72)
3	Remaining Amortization at time of Redemption	5,894
	Foreign Exchange (Gain)/Loss on Redemption	
4	Actual Exchage Rate	1.36227
5	Historic Exchange Rate	1.36293
6	Net Change in Rate	(0.00066)
7	$US Purchase Requirements	160,009
8	Foreign Exchange (Gain)/Loss on Redemption	(106)
9	Total Debt Redemption Costs	5,788

l No Change from 2003 forecast.

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REVENUE REQUIREMENT
TAB 16

REGULATORY PROCEEDING COSTS

In accordance with NEB Decision RH-1-2002, TransCanada established a deferral account for regulatory proceeding costs effective for the 2003 Test Year.

Schedule 16.0 details regulatory proceeding costs for 2002 actual, 2003 actual and 2004 test year.

The regulatory proceeding costs for 2002 were formerly included in total Operations, Maintenance and Administration, and although not subject to deferral account treatment in 2002, 2002 costs have been shown on the following schedules for comparative purposes only.

Regulatory proceeding costs include the following cost components:

- Consultants
- External legal counsel
- Contract service costs
- Employee expenses
- Transcript costs
- Translation costs
- Public notice costs
- Incremental costs resulting from any proceedings held outside of Calgary

REGULATORY PROCEEDING COSTS FOR THE BASE YEAR
ENDED DECEMBER 31, 2002, ACTUAL YEAR ENDED DECEMBER 31, 2003
AND TEST YEAR ENDING DECEMBER 31, 2004

($ 000)

Ln. No.	Particulars	2002 Base Year	2003 Actual Year		2004 Test Year
	(a)	(b)	(c)		(d)
	External Legal Costs				
1	RH-4-2001 Fair Return	531	0		0
2	RH-R-1-2002 Review and Variance	131	122	I	0
3	Federal Court of Appeal (Re: RH-R-1-2002)	0	266	I	50
4	RH-1-2002 2003 Tolls	67	1,087	I	0
5	2004 Tolls Application	0	70	I	400
6	2005 Tolls Application	0	0		150
7	Total External Legal Costs	729	1,545	I	600
	Regulatory Costs				
8	RH-1-2001 2001-2002 Mainline Tolls	48	0		0
9	RH-4-2001 Fair Return	2,631	0		0
10	RH-R-1-2002 Review and Variance	144	7	I	0
11	RH-1-2002 2003 Tolls	306	643	I	0
12	2004 Tolls Application	0	295	I	1,500
13	2005 Tolls Application	0	0		1,000
14	Total Regulatory Costs	3,129	945	I	2,500
15	Total Regulatory Proceeding Costs	3,858	2,490	I	3,100

I Updated to reflect 2003 actual costs.

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RATE OF RETURN

RATE OF RETURN

Base Year ended December 31, 2002

Rate of Return information for the Base Year ended December 31, 2002 is provided on Rate of Return Schedules 1.1 through 4.1. The overall rate of return includes the return on equity using the NEB ROE formula established in the RH-2-94 Decision at 9.53 percent and a common equity ratio of 33 percent based on the RH-4-2001 Decision. The return on equity for 2002 is subject of the outcome of the appeal of the Board's RH-R-1-2002 Decision.

Actual Year ended December 31, 2003

Rate of Return information for the Actual Year ended December 31, 2003 is provided on Rate of Return Schedules 1.2 through 4.2. The overall rate of return includes the return on equity using the NEB ROE formula established in the RH-2-94 Decision at 9.79 percent and a common equity ratio of 33 percent as based on the RH-4-2001 Decision. In its RH-1-2002 Decision, the Board established that 2003 Tolls shall remain interim pending the disposition of TransCanada's appeal of the Board's RH-R-1-2002 Decision.

Test Year ending December 31, 2004

Rate of Return information for the Test Year ending December 31, 2004 is provided on Rate of Return Schedules 1.3 through 4.3.

The Test Year rate of return calculations have been determined using a proposed deemed common equity component of 40 percent with a return on common equity of 11 percent (After Tax Weighted Average Cost of Capital of 6.9 percent). Supporting evidence for the rate of return on equity and the deemed common equity component of total capitalization is contained in Volume 1, Appendix B.

Schedule 1.3

Schedule 1.3 provides a summary of the deemed average capitalization which has been equated to the average utility rate base plus the average gas plant under construction projected to be outstanding during the Test Year.

During the Test Year, TransCanada is forecasting the redemption of the US$460 million 8.25 percent Junior Subordinated Debentures due 2047 (“JSD”). The JSD, along with the 8.75 percent Junior Subordinated Debentures due 2045 (collectively, “preferred securities”), with concurrence of the Tolls Task Force, were introduced to the Mainline’s capital structure in 1998 as a cost-effective alternative to term preferred shares. As discussed in the Company’s Fair Return Standard evidence, the JSD are no longer well-suited for their intended purpose and TransCanada is proposing to replace this ten per cent preferred component with seven per cent unfunded debt and three per cent common equity that should provide equivalent credit support for the Mainline at a lower cost to shippers, as outlined in Attachment 1. As noted above and as outlined in Schedule 15.3, Sheet 1 of 1, the redemption of the JSD is forecast to result in a pre-tax gain of $67 million, reflecting the net foreign exchange gain on principal partially offset by unamortized debt, discount and expense items associated with the JSD. The full net forecast gain is conveyed to shippers in Test Year tolls.

In addition, TransCanada is proposing the redemption of the 8.50 percent Debentures (U.S. Series) due 2023. Although the 8.50 percent Debentures have been callable for some time, the low historical exchange rate at the time of original issue of $1.24725 plus the call premium has made it uneconomic to do so, and would have resulted in a significant one-time cost to shippers. TransCanada is proposing to utilize a portion of the one-time gain from the redemption of the JSD to offset this loss as outlined in Schedule 15.3, Sheet 1 of 1. The 8.50 percent Debentures would be replaced with unfunded debt during the Test Year. Redeeming the 8.50 percent Debentures will reduce financial charges and the Mainline’s exposure to foreign exchange fluctuations by removing a significant US dollar liability from the ratebase.

In determining the overall requested rate of return:

- funded debt represents the average principal of debt capital associated with the utility investments projected to be outstanding during the Test Year.
- Junior Subordinated Debentures consist of Canadian Originated Preferred Securities (COPrS) issued in 1998.
- unfunded/(prefunded) debt represents the balance of total capitalization. This is determined on a monthly basis and computed as a 13-month average to represent the balance of the capitalization. During periods in which the Mainline is in an unfunded position, the short-term estimate of 3.35 percent has been applied; when prefunded, the cost rate is 8.73 percent, equivalent to the Mainline's average funded cost of debt.
- common equity is deemed to be 40 percent of the total capitalization, employing a 11 percent return on common equity.

Schedule 2.3

Schedule 2.3 provides the determination of the weighted average cost of debt capital by issue for the Test Year ending December 31, 2004.

Schedule 2.3.1

Schedule 2.3.1 provides the average funded debt by issue for the Test Year ending December 31, 2004.

Schedule 2.3.2

Schedule 2.3.2 provides the amortization of debt, discount and expense for the Test Year ending December 31, 2004.

Schedule 3.3

Schedule 3.3 provides the determination of the weighted average cost of junior subordinated debentures by issue for the Test Year ending December 31, 2004.

Schedule 3.3.1

Schedule 3.3.1 provides the average junior subordinated debentures by issue for the Test Year ending December 31, 2004.

Schedule 3.3.2

Schedule 3.3.2 provides the amortization of junior subordinated debenture debt, discount and expenses for the Test Year ending December 31, 2004.

Schedule 4.3

Schedule 4.3 provides the calculation of the monthly unfunded/prefunded average position.

CALCULATION OF REPLACING THE PREFERRED SECURITIES WITH DEBT & EQUITY
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	%	AMOUNT ($000)	
	(a)	(b)	(c)	
1	2004 13-month average total capitalization		$8,206,519	I
2	Preferred securities as a % of total capitalization	10.00		
3	Cost rate of preferred securities (pre-tax)	7.57		
4	Tax rate	35.932		I
5	Cost of preferred securities at 7.57% (pre-tax)		$62,123	I
6	Cost of preferred securities at 7.57% (after-tax)		$39,801	I
	Replace 10% preferred securities with 7% unfunded debt and 3% equity			
7	Cost of equity at 11% ROE		$27,082	I
8	Cost of unfunded debt at 3.35% (after-tax)		$12,329	I
9	Total		$39,411	I

I Updated to reflect changes in 2004 capitalization and income tax rate.

DEEMED AVERAGE CAPITALIZATION AND
REQUESTED OVERALL RATE OF RETURN
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003

LINE NO.	PARTICULARS	AMOUNT ($000)	RATIO %	COST RATE %	COST COMPONENT %	
	(a)	(b)	(c)	(d)	(e)	
1	Debt - Funded (Schedule 2.2)	4,900,060	57.21	9.09	5.20	I
2	- Prefunded (Schedule 4.2)	(32,219)	(0.38)	9.01	(0.03)	I
3	- Unfunded (Schedule 4.2)	59,679	0.70	3.11	0.02	I
4	Total Debt	4,927,521	57.53		5.19	I
5	Junior Subordinated Debentures (Schedule 3.2)	811,111	9.47	8.54	0.81	
6	Common Equity	2,826,490	33.00	9.79	3.23	I
7	Total Capitalization	8,565,121	100.00		9.23	I
8	Rate Base (Schedule 5.2)	8,555,713				I
9	GPUC	9,408				I
10	Total Capitalization	8,565,121				I

I Updated to reflect 2003 actual amounts.

WEIGHTED AVERAGE COST OF DEBT CAPITAL
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l

LINE NO.	PARTICULARS	AVERAGE OUTSTANDING ($000) (1)	FINANCIAL CHARGES ($000) (2)	COST RATE (%)	SCHEDULE REFERENCE
	(a)	(b)	(c)	(d)	(e)
	F.M.P.L. Bonds				
1	16.50% (U.K.) due 2007	54,708	9,075		
2	Total Bonds	54,708	9,075		
	Debentures				
3	11.100% Series N due 2014	125,000	13,875		
4	10.500% Series O due 2010	130,000	13,650		
5	10.500% Series P due 2019	100,000	10,500		
6	10.625% Series Q due 2009	250,000	26,563		
7	11.850% Series R due 2008	100,000	11,850		
8	11.900% Series S due 2015	150,000	17,850		
9	11.800% Series U due 2020	249,635	29,457		
10	9.800% Series V due 2017	100,000	9,800		
11	9.450% Series W due 2018	150,000	14,175		
12	9.875% (U.S.) due 2021	462,156	59,645		
13	8.625% (U.S.) due 2012	240,093	26,048		
14	8.500% (U.S.) due 2023	249,450	25,670		
15	Total Debentures	2,306,334	259,082		
	Medium Term Notes				
16	8.940% due Feb 03, 2003	769	69		
17	8.550% due Jun 11, 2003	16,246	1,389		
18	8.150% due Jul 07, 2003	8,938	728		
19	7.950% due Jul 28, 2003	11,846	942		
20	7.800% due Aug 25, 2003	9,169	715		
21	9.500% due May 20, 2011	60,000	5,700		
22	9.350% due May 27, 2019	12,500	1,169		
23	9.500% due Oct 12, 2004	31,000	2,945		
24	9.600% due Oct 12, 2004	10,000	960		
25	9.950% due Dec 01, 2022	25,000	2,488		
26	8.550% due Feb 01, 2006	80,380	6,872		
27	8.290% due Feb 05, 2026	113,500	9,409		
28	8.210% due Apr 25, 2030	50,000	4,105		
29	8.230% due Jan 16, 2031	50,000	4,115		
30	8.200% due Aug 15, 2031	48,000	3,936		
31	8.290% due Feb 05, 2026	127,100	10,537		
32	7.310% due Jan 15, 2027	106,000	7,749		
33	5.850% due Mar 08, 2004	105,000	6,143		
34	7.900% due Apr 15, 2027	174,500	13,786		
35	6.270% due Jul 18, 2007	106,900	6,703		
36	6.890% due Aug 07, 2028	173,000	11,920		
37	6.150% due Oct 01, 2007	150,000	9,225		
38	6.280% due May 26, 2028	175,000	10,990		
39	5.910% due Sep 17, 2008	3,169	187		
40	5.840% due Jun 27, 2008	256,000	14,950		
41	6.050% due Feb 15, 2007	275,000	16,638		
42	5.400% due Feb 08, 2005	180,000	9,720		
43	5.858% due Feb 19, 2010	180,000	10,544		
44	Total Medium Term Notes	2,539,018	174,631		
45	Total Bonds, Debentures and Notes	4,900,060	442,788		
46	Amortization of Debt, Discount and Expense		2,658		Schedule 2.2.2
47	Total	4,900,060	445,446	9.09%	

(1) Stated in $ Cdn. with foreign issues converted at their historic rate of issue.
(2) Foreign financial charges are converted to $ Cdn. at the projected rates of $1.00 U.S. =$1.51Cdn or £1.00 = $2.20 Cdn

l No change from 2003 Forecast.

ESTIMATED AVERAGE FUNDED DEBT
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 I
($000)

LINE NO.	PARTICULARS	2002 DEC.	2003 JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	TOTAL	13 month AVERAGE
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	F.M.P.L. Bonds															
1	16 1/2% - 2007 (U.K.)	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	711,204	54,708
2	Total Bonds	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	54,708	711,204	54,708
	Debentures															
3	11.10 % N - 2014	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	1,625,000	125,000
4	10.50 % O - 2010	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	1,690,000	130,000
5	10.50 % P - 2019	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,300,000	100,000
6	10.625 % Q - 2009	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	3,250,000	250,000
7	11.85 % R - 2008	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,300,000	100,000
8	11.90 % S - 2015	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,950,000	150,000
9	11.80 % U - 2020	249,635	249,635	249,635	249,635	249,635	249,635	249,635	249,635	249,635	249,635	249,635	249,635	249,635	3,245,255	249,635
10	9.80 % V - 2017	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,300,000	100,000
11	9.45 % W - 2018	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,950,000	150,000
12	9.875 % -2021 (U.S.)	462,156	462,156	462,156	462,156	462,156	462,156	462,156	462,156	462,156	462,156	462,156	462,156	462,156	6,008,028	462,156
13	8.625 % -2012 (U.S.)	240,093	240,093	240,093	240,093	240,093	240,093	240,093	240,093	240,093	240,093	240,093	240,093	240,093	3,121,209	240,093
14	8.5 % -2023 (U.S.)	249,450	249,450	249,450	249,450	249,450	249,450	249,450	249,450	249,450	249,450	249,450	249,450	249,450	3,242,850	249,450
15	Total Debentures	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	2,306,334	29,982,342	2,306,334

Note 1: Stated in $ Cdn with Foreign issues converted at their historic rate of issue
I No change from 2003 Forecast.

ESTIMATED AVERAGE FUNDED DEBT
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS (a) Rate	Issue Date	Maturity Date	2002 DEC. (b)	2003 JAN. (c)	FEB. (d)	MAR. (e)	APR. (f)	MAY (g)	JUNE (h)	JULY (i)	AUG. (j)	SEPT. (k)	OCT. (l)	NOV. (m)	DEC. (n)	TOTAL (o)	13 month AVERAGE (p)
	Medium Term Notes:																	
1	8.940%	Feb 01, 1993	Feb 03, 2003	5,000	5,000	0	0	0	0	0	0	0	0	0	0	0	10,000	769
2	8.550%	Jun 11, 1993	Jun 11, 2003	35,200	35,200	35,200	35,200	35,200	35,200	0	0	0	0	0	0	0	211,200	16,246
3	8.150%	Jul 07, 1993	Jul 07, 2003	16,600	16,600	16,600	16,600	16,600	16,600	16,600	0	0	0	0	0	0	116,200	8,938
4	7.950%	Jul 28, 1993	Jul 28, 2003	22,000	22,000	22,000	22,000	22,000	22,000	22,000	0	0	0	0	0	0	154,000	11,846
5	7.800%	Aug 25, 1993	Aug 25, 2003	14,900	14,900	14,900	14,900	14,900	14,900	14,900	14,900	0	0	0	0	0	119,200	9,169
6	9.500%	May 20, 1994	May 20, 2011	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	780,000	60,000
7	9.350%	May 27, 1994	May 27, 2019	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	162,500	12,500
8	9.500%	Oct 11, 1994	Oct 12, 2004	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	403,000	31,000
9	9.600%	Nov 29, 1994	Oct 12, 2004	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	130,000	10,000
10	9.950%	Dec 01, 1994	Dec 01, 2022	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	325,000	25,000
11	8.550%	Sep 06, 1995	Feb 01, 2006	80,380	80,380	80,380	80,380	80,380	80,380	80,380	80,380	80,380	80,380	80,380	80,380	80,380	1,044,940	80,380
12	8.290%	Feb 05, 1996	Feb 05, 2026	113,500	113,500	113,500	113,500	113,500	113,500	113,500	113,500	113,500	113,500	113,500	113,500	113,500	1,475,500	113,500
13	8.210%	Apr 25, 1996	Apr 25, 2030	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	650,000	50,000
14	8.230%	May 28, 1996	Jan 16, 2031	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	650,000	50,000
15	8.200%	Aug 01, 1996	Aug 15, 2031	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	624,000	48,000
16	8.290%	Oct 04, 1996	Feb 05, 2026	127,100	127,100	127,100	127,100	127,100	127,100	127,100	127,100	127,100	127,100	127,100	127,100	127,100	1,652,300	127,100
17	7.310%	Dec 05, 1996	Jan 15, 2027	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	1,378,000	106,000
18	5.850%	Mar 07, 1997	Mar 08, 2004	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	1,365,000	105,000
19	7.900%	Apr 15, 1997	Apr 15, 2027	174,500	174,500	174,500	174,500	174,500	174,500	174,500	174,500	174,500	174,500	174,500	174,500	174,500	2,268,500	174,500
20	6.270%	Jul 18, 1997	Jul 18, 2007	106,900	106,900	106,900	106,900	106,900	106,900	106,900	106,900	106,900	106,900	106,900	106,900	106,900	1,389,700	106,900
21	6.890%	Jul 30, 1997	Aug 07, 2028	173,000	173,000	173,000	173,000	173,000	173,000	173,000	173,000	173,000	173,000	173,000	173,000	173,000	2,249,000	173,000
22	6.150%	Sep 30, 1997	Oct 01, 2007	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,950,000	150,000
23	6.280%	May 26, 1998	May 26, 2028	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	2,275,000	175,000
24	5.910%	Sep 17, 2001	Sep 17, 2008	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	41,197	3,169
25	5.840%	Jun 29, 1998	Jun 27, 2008	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	256,000	3,328,000	256,000
26	6.050%	Nov 23, 1998	Feb 15, 2007	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	3,575,000	275,000
27	5.400%	Feb 08, 1999	Feb 08, 2005	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	2,340,000	180,000
28	5.858%	Feb 19, 1999	Feb 19, 2010	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	2,340,000	180,000
29	Total Medium Term Notes			2,585,749	2,585,749	2,580,749	2,580,749	2,580,749	2,580,749	2,545,549	2,506,949	2,492,049	2,492,049	2,492,049	2,492,049	2,492,049	33,007,237	2,539,018
30	Total Average Funded Debt			4,946,791	4,946,791	4,941,791	4,941,791	4,941,791	4,941,791	4,906,591	4,867,991	4,853,091	4,853,091	4,853,091	4,853,091	4,853,091	63,700,783	4,900,060

l No change from 2003 Forecast.

TransCanada
In business to deliver

AMORTIZATION OF DEBT, DISCOUNT AND EXPENSE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	TOTAL FINANCING COST	UNAMORTIZED BALANCE DEC. 31/02	ADDITIONAL COSTS	TOTAL AMORTIZATION	UNAMORTIZED BALANCE DEC. 31/03
	(a)	(b)	(c)	(d)	(e)	(f)
	F.M.P.L. Bonds					
1	16 1/2 % due 2007 (U.K.)	1,973	362	0	77	285
2	Total Bonds	1,973	362	0	77	285
	Debentures					
3	11.10 % N due 2014	1,009	465	0	40	425
4	10.50 % O due 2010	1,309	473	0	62	411
5	10.50 % P due 2019	547	302	0	18	284
6	10.625 % Q due 2009	3,211	1,098	0	161	937
7	11.85 % R due 2008	1,023	312	0	57	255
8	11.90 % S due 2015	1,484	753	0	59	694
9	11.80 % U due 2020	3,170	1,901	0	106	1,795
10	9.80 % V due 2017	735	442	0	29	413
11	9.45 % W due 2018	1,617	986	0	65	921
12	9.875% US due 2021	5,296	3,191	0	177	3,014
13	8.625% US due 2012	3,609	1,700	0	181	1,519
14	8.50% US due 2023	2,922	1,945	0	96	1,849
15	Total Debentures	25,932	13,568	0	1,051	12,517
	Notes					
16	Medium Term Notes	18,970	7,544	0	1,519	6,025
17	Proposed 2003 Issues	0	0	0	0	0
18	Sub-Total Amortization of Debt, Discount & Expense	46,875	21,474	0	2,647	18,827
	Trust Deed Amendment Costs					
19	16 1/2 % due 2007 (U.K.)	159	53	0	11	42
20	Total Trust Deed Amendment Costs	159	53	0	11	42
21	Total Amortization of Debt, Discount & Expense	47,034	21,527	0	2,658	18,869

l No change from 2003 Forecast.

JUNIOR SUBORDINATED DEBENTURES
WEIGHTED AVERAGE COST OF DEBT CAPITAL
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003

LINE NO.	PARTICULARS	AVERAGE OUTSTANDING ($000) (1)	FINANCIAL CHARGES ($000) (2)	COST RATE (%)
	(a)	(b)	(c)	(d)
1	8.750% US due Jul 24, 2045	117,429	11,384	
2	8.250% US due Oct 01, 2047	693,682	57,305	
3	Total Medium Term Notes	811,111	68,688	
4	Amortization of Debt, Discount and Expense (Schedule 3.2.2)		568	
5	Total	811,111	69,256	8.54%

(1) Stated in $ Cdn. with foreign issues converted at their historic rate of issue.
(2) Foreign financial charges are converted to $ Cdn. at the projected rates of $1.00 U.S. =$1.51Cdn

JUNIOR SUBORDINATED DEBENTURES
ESTIMATED AVERAGE FUNDED DEBT
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS			2002 DEC.	2003 JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	TOTAL	13 month AVERAGE
	(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	8.750%	Jul 23, 1996	Jul 24, 2045	218,082	218,082	218,082	218,082	218,082	218,082	218,082	0	0	0	0	0	0	1,526,574	117,429
2	8.250%	Oct 01, 1998	Oct 01, 2047	693,682	693,682	693,682	693,682	693,682	693,682	693,682	693,682	693,682	693,682	693,682	693,682	693,682	9,017,863	693,682
3	Total Junior Subordinated Debentures			911,764	911,764	911,764	911,764	911,764	911,764	911,764	693,682	693,682	693,682	693,682	693,682	693,682	10,544,437	811,111

Note 1: Stated in $ Cdn with Foreign issues converted at their historical rate of issue.

l No Change from 2003 Forecast.

JUNIOR SUBORDINATED DEBENTURES
AMORTIZATION OF DEBT, DISCOUNT AND EXPENSE
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003 l
($000)

LINE NO.	PARTICULARS	TOTAL FINANCING COST	UNAMORTIZED BALANCE DEC. 31/02	ADDITIONAL COSTS	TOTAL AMORTIZATION	AMORTIZATION ON REDEMPTION	UNAMORTIZED BALANCE DEC. 31/03
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	8.75% due 2045 (U.S.)	6,864	5,966	0	72	5,894	0
2	8.25% due 2047 (U.S.)	24,312	22,245	0	496	0	21,749
3	Total Amortization of Debt, Discount & Expense Junior Subordinated Debentures	31,176	28,211	0	568	5,894	21,749

l No Change from 2003 Forecast.

TransCanada
In business to deliver

2004 Mainline Tolls and Tariff Application
Rate of Return
Schedule 4.2
Sheet 1 of 1
Revised February 2004 I

CALCULATION OF UNFUNDED / PREFUNDED AVERAGE POSITION
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

LINE NO.	PARTICULARS	2002 DEC.	2003 JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	13 month AVERAGE
1	Total Average Funded Debt	4,946,791	4,946,791	4,941,791	4,941,791	4,941,791	4,941,791	4,906,591	4,867,991	4,853,091	4,853,091	4,853,091	4,853,091	4,853,091	4,900,060
2	Total Junior Subordinated Debentures	911,764	911,764	911,764	911,764	911,764	911,764	911,764	693,682	693,682	693,682	693,682	693,682	693,682	811,111
3	Total Unfunded Debt	0	0	0	0	0	0	0	154,638	153,899	138,531	122,754	109,492	96,508	59,679 I
4	Total Prefunded Debt	(7,092)	(32,485)	(47,450)	(66,781)	(83,278)	(101,146)	(80,616)	0	0	0	0	0	0	(32,219) I
5	Total Debt (67%)	5,851,463	5,826,070	5,806,105	5,786,774	5,770,277	5,752,409	5,737,739	5,716,311	5,700,672	5,685,304	5,669,527	5,656,265	5,643,281	5,738,631 I
6	Total Equity (33%)	2,882,065	2,869,557	2,859,724	2,850,203	2,842,077	2,833,277	2,826,051	2,815,497	2,807,793	2,800,224	2,792,453	2,785,921	2,779,527	2,826,490 I
7	Total Capitalization	8,733,529	8,695,628	8,665,830	8,636,978	8,612,355	8,585,687	8,563,791	8,531,808	8,508,465	8,485,528	8,461,980	8,442,186	8,422,808	8,565,121 I

I Updated to reflect 2003 actual balances.

DEEMED AVERAGE CAPITALIZATION AND
REQUESTED OVERALL RATE OF RETURN
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	AMOUNT ($000)	RATIO %	COST RATE %	COST COMPONENT %	
	(a)	(b)	(c)	(d)	(e)	
1	Debt - Funded (Schedule 2.3)	4,647,729	56.63	8.85	5.01	I
2	- Prefunded (Schedule 4.3)	(277,418)	(3.38)	8.73	(0.30)	I
3	- Unfunded (Schedule 4.3)	180,079	2.19	3.35	0.07	I
4	Total Debt	4,550,390	55.45		4.78	I
5	Junior Subordinated Debentures (Schedule 3.3)	373,521	4.55	7.27	0.33	
6	Common Equity	3,282,608	40.00	11.00	4.40	I
7	Total Capitalization	8,206,519	100.00		9.51	I
8	Rate Base (Schedule 5.3)	8,202,682				I
9	GPUC	3,837				I
10	Total Capitalization	8,206,519				I

I Updated to reflect changes in capitalization for 2004.

CALCULATION OF UNFUNDED / PREFUNDED AVERAGE POSITION
FOR TEST YEAR ENDING DECEMBER 31, 2004
($000)

LINE NO.	PARTICULARS	2003 DEC.	2004 JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	13 month AVERAGE	
1	Total Average Funded Debt	4,853,091	4,853,091	4,853,091	4,748,091	4,748,091	4,748,091	4,748,091	4,498,641	4,498,641	4,498,641	4,457,641	4,457,641	4,457,641	4,647,729	
2	Total Junior Subordinated Debentures	693,682	693,682	693,682	693,682	693,682	693,682	693,682	0	0	0	0	0	0	373,521	
3	Total Unfunded	0	0	0	0	0	0	0	403,565	389,990	377,022	405,549	391,596	373,299	180,079	I
4	Total Prefunded	(530,961)	(546,363)	(561,262)	(470,955)	(485,430)	(499,898)	(511,561)	0	0	0	0	0	0	(277,418)	I
5	Total Debt (60%)	5,015,812	5,000,410	4,985,511	4,970,818	4,956,343	4,941,875	4,930,212	4,902,206	4,888,631	4,875,663	4,863,190	4,849,237	4,830,940	4,923,911	I
6	Total Equity (40%)	3,343,874	3,333,607	3,323,674	3,313,878	3,304,229	3,294,583	3,286,808	3,268,137	3,259,088	3,250,442	3,242,126	3,232,824	3,220,627	3,282,608	I
7	Total Capitalization	8,359,686	8,334,017	8,309,185	8,284,696	8,260,572	8,236,458	8,217,020	8,170,343	8,147,719	8,126,105	8,105,316	8,082,061	8,051,567	8,206,519	I

I Updated to reflect impact of 2003 actuals on opening balances for 2004 and revised 2004 capitalization.

2004 Mainline Tolls and Tariff Application
February 2004 Update

TOLL DESIGN

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TOLL METHODOLOGY OVERVIEW

The following summary outlines the content of the Toll Design section.

Tab 1	Cost allocation units are calculated for each domestic zone and export point using the same methodology approved by the Board in preceding tolls decisions.
Tab 2	TransCanada's cost of service is functionalized into Metering and Transmission which is further classified into fixed and variable costs.
Tab 3	The cost allocation units from Tab 1 are totalled and divided into the functionalized and classified cost of service from Tab 2 (net of miscellaneous revenue from Tab 4) to determine system average unit costs. The system average unit costs are multiplied by the individual allocation units to provide allocated costs to each domestic zone and export point. These are divided by the respective fixed energy (GJ) and variable energy (GJ) allocation units to determine the FT demand and commodity tolls.
Tab 4	Miscellaneous Revenue is calculated.
Tab 5	Proposed tolls effective January 1, 2004.

DISTANCE METHODOLOGY OVERVIEW

In calculating distances for tolling purposes, TransCanada has historically used, with Board approval, the route from Empress along the Western Section, through Northern Ontario, down the Central Section to Maple (near Toronto) and then along the Montreal Line.

TransCanada then takes into consideration any shorter distances that gas may travel, such as gas through the Great Lakes/Union route, the Thunder Bay Bypass,

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the North Bay Shortcut and the Winchester Shortcut. The energy-distance adjustments related to these shortcuts are set out in Tab 1 of the Toll Design Section, Schedules 1.4, 1.5, 1.6, and 1.7 respectively.

Typically, there are minor changes each year in distances for tolling purposes. The domestic load centres are based on an energy-weighted average distance to each distributor's delivery points. As energy distributions change from year to year, the average load centre changes accordingly. Furthermore, as throughput changes from year to year the relative energy-distance credits of the Thunder Bay Bypass, North Bay Shortcut, Winchester Shortcut, and Great Lakes/Union route may also change. Updated measurements resulting from revised surveys or changes in the configuration of facilities (for example the additions of laterals, shortcuts, or additional facilities) may result in changes to distances.

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DETERMINATION OF ALLOCATION UNITS

Schedule 1.1

(a) Base Year - Ended December 31, 2002

A summary of the fixed energy (GJ), fixed energy-distance (GJ-km), variable energy (TJ), and variable energy-distance (TJ-km) allocation units are shown on Schedule 1.1.

The Base Year components of Schedule 1.1 summarize the Firm Transportation at the original contracted market location. The Base Year data do not reflect the use of IT service to nominate FT-Makeup amounts which was a permitted service feature in 2002.

(b) Test Year - Ending December 31, 2004

The fixed energy and variable energy allocation units used to design the tolls for the Test Year are based on known FT contracts as of January 19, 2004.

TransCanada takes into consideration any shorter distances that gas may travel along the integrated Mainline system. These energy-distance adjustments are set out in Schedules 1.4, 1.5, 1.6, and 1.7 respectively.

The 2004 allocation units reflect the following contract assumptions:

a) Non-renewals effective from November 1, 2003 to April 30, 2004 of 874 TJ/d.

b) Excludes any potential non-renewals after April 30, 2004.

c) Includes new longhaul Firm Transportation (FT) contracts from Empress and Saskatchewan of 101 TJ/d, new FT contracts from Empress and Saskatchewan to delivery points in western Canada of 593 TJ/d, and new shorthaul FT contracts from Dawn and St. Clair of 226 TJ/d beginning on November 1, 2003 through April 1, 2004.

Includes the restructuring of Union Gas' FT contracts of 60 TJ/d from the Union NDA and WDA to the Union CDA, and STS contracts with a reduction of 8 TJ/d from the Union NDA and an increase of 3.15 TJ/d from the Union WDA, effective November 1, 2003.

Schedule 1.2

This schedule calculates the load centres for each Distributor Delivery Area as approved by the Board in its RH-1-97 Decision. A load centre is the energy-weighted average distance of haul for deliveries to the Distributor Delivery Area during the Base Year. Canadian deliveries are made to delivery areas within zones. Load centres are calculated for Canadian Distributor Delivery Areas only, as export service is based on point-to-point deliveries. The Distributor Delivery Area load centres calculated in Schedule 1.2 are used to create the zone load centres in Schedule 1.1. The winter deliveries are from January 1, 2002 to March 31, 2002 and November 1, 2002 to December 31, 2002.

Base Year metered energy at each meter station within the Distributor Delivery Area is used in the load centre calculation. For the Union SWDA, TransCanada's M12 energy units are removed from the Dawn-Union metered energy units as these energy units represent TransCanada's transportation on the Union system. For the same reason, TransCanada's C1 energy units are removed from the Parkway Belt-Union metered energy units in the Union CDA load centre calculation.

There are two locations where both export and domestic energy flows through the same meter. These locations are: Spruce (within the Centra Gas Holdings MDA), and Dawn (within the Union SWDA). Therefore, an adjustment has been made to remove export energy units from the total metered energy at these locations. As approved in the RH-1-97 Decision, the export energy units removed are based on invoiced energy units for the Base Year.

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Schedule 1.3

Base Year and Test Year

The purpose of this schedule is to calculate the TransGas Intra-Saskatchewan allocation units in accordance with the approved TransGas Tolling Methodology. However, there are no TransGas Intra-Saskatchewan allocation units forecast for 2004.

TransGas has contracted to transport all energy units to the Saskatchewan Zone with the primary receipt point at Empress. These allocation units are reflected in Schedule 1.2 for the Base Year and Schedule 1.1 for the Test Year.

Schedule 1.4

This schedule provides the determination of distance adjustments associated with the Great Lakes/Union Route. The Great Lakes/Union route adjustment reduces the fixed energy-distance (GJ-km) and variable energy-distance (TJ-km) allocation units for the Eastern Zone and eastern export points to reflect the shorter length of haul via the Great Lakes Gas Transmission system, and the Union Gas system (collectively "Great Lakes/Union route").

The variable energy (TJ) allocation units for the adjustment are calculated by subtracting the Sault Ste. Marie (SSM), St. Clair and the Southwestern Delivery Area (SWDA) variable energy allocation units from the total Great Lakes/Union route variable energy allocation units. The SWDA allocation units are calculated by subtracting the SSM, St. Clair and total Great Lakes/Union route variable energy allocation units from the utilization of TransCanada's capacity on the Union System. The utilization of TransCanada's Union M12 contract for the purpose of Great Lakes/Union transportation adjustments, is based on M12 utilization less contracted shorthauls on TransCanada from St. Clair and Dawn.

The fixed energy (GJ) allocation units for the adjustment are calculated by subtracting the fixed energy allocation units for SSM, St. Clair and the SWDA from the fixed energy allocation units for the Great Lakes/Union route. The fixed energy allocation units for the Great Lakes/Union route are determined by distributing the total fixed energy allocation units downstream of the Manitoba Zone in proportion to the variable energy allocation units for TransCanada's Northern Ontario and Great Lakes/Union routes.

The Great Lakes/Union route fixed energy-distance and variable energy-distance adjustments are pro-rated to the Eastern Zone and eastern export points, based on their total fixed energy and variable energy allocation units less the deliveries considered to travel on the northern route and those deliveries that can only be delivered via the southern route.

Schedule 1.5

The Thunder Bay by-pass adjustment reflects the reduction in the distance of haul of energy transported via the Thunder Bay by-pass by reducing the applicable fixed energy-distance and variable energy-distance allocation units in the Western Zone and in each of the downstream zones and export points.

The total fixed energy-distance (GJ-km) and variable energy-distance (TJ-km) adjustments are calculated by multiplying the deliveries through the Thunder Bay by-pass by the reduction in the distance of haul. These total adjustments are then pro-rated to the appropriate zones based on the fixed energy (GJ) and variable energy (TJ) allocation units downstream of the by-pass via TransCanada's northern route. The downstream allocation units include:

(a) the allocation units for delivery points Geraldton, Long Lac, Beardmore and Nipigon Power in the Western Zone;

(b) the allocation units for all delivery points except Sault Ste. Marie in the Northern Zone;

(c) the allocation units for all delivery points in the Eastern Zone less the GLGT/Union transportation energy units; and

(d) the allocation units for eastern export service less the applicable GLGT/Union transportation energy units.

Schedule 1.6

The North Bay Shortcut adjustments reflect the reduction in the distance of haul of energy transported via the North Bay Shortcut by reducing the applicable fixed energy-distance and variable energy-distance allocation units east of Mainline Valve (“MLV”) 130.

The total variable energy-distance (TJ-km) and fixed energy-distance (GJ-km) allocation units for the adjustment are calculated by multiplying the deliveries through the North Bay Shortcut by the distance saved. (The North Bay Shortcut delivery energy units do not include the energy forecasted to flow on the Winchester Shortcut.) These total energy-distance adjustments are then pro-rated to the appropriate zones and export points based on the variable energy (TJ) and fixed energy (GJ) allocation units downstream of the by-pass, which include the allocation units for:

(a) Eastern Zone service east of MLV 130; and

(b) Eastern export service east of MLV 130.

There are no Iroquois export energy units eligible for North Bay Shortcut savings after September 24, 1998 as described in the explanation for Schedule 1.7.

Schedule 1.7

The Winchester Shortcut went into service in September 25,1998 and all deliveries to the Iroquois export point flow via this route. As a result, Iroquois receives energy-distance savings from the Winchester Shortcut for 100% of its volumes.

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For energy units flowing from the Winchester Shortcut into the Montreal line, energy-distance savings have been allocated to locations downstream which include the allocation units for:

(a) Eastern Zone service east of MLV 130; and

(b) Eastern export service (excluding Iroquois) east of MLV 130.

The total variable energy-distance (TJ-km) and fixed energy-distance (GJ-km) allocation units for the adjustment are calculated by multiplying the deliveries through the Winchester Shortcut by the distance saved. The distance saved is based on comparing the shorter distance through the Winchester Shortcut as compared to the traditional route (Line 100-1). The resulting energy-distance adjustments are first allocated to all of the Iroquois export energy units, with the remainder prorated to the other locations eligible to receive Winchester Shortcut distance savings.

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SUMMARY OF ALLOCATION UNITS AS ADJUSTED

			VARIABLE ALLOCATION UNITS					FIXED ALLOCATION UNITS			
		KM	BASE YEAR ENDED DEC. 31, 2002		TEST YEAR ENDING DEC. 31, 2004		KM	BASE YEAR ENDED DEC. 31, 2002		TEST YEAR ENDING DEC. 31, 2004	
LINE NO.	PARTICULARS	LOAD CENTRE	TJ	TJ-km	TJ	TJ-km	LOAD CENTRE	GJ	GJ-km	GJ	GJ-km
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	CANADIAN FIRM SERVICE										
	Saskatchewan Zone										
1	TransGas Ltd.	524.62	10,365.1	5,437,759.2	88,560.0	46,460,347.2	567.59	28,493	16,172,342	241,967	137,338,050
2	Centra Gas (Manitoba)- SDA	611.59	1,301.9	796,252.3	1,258.0	769,380.2	611.59	5,582	3,413,895	5,582	3,413,895
3	Total Zone Firm Service	525.84	11,667.1	6,234,011.5	89,818.0	47,229,727.4	568.58	34,075	19,586,237	247,549	140,751,945
	Herbert to Saskatchewan Zone										
4	TransGas Ltd.	333.12	0.0	0.0	7,869.0	2,621,281.9	375.86	0	0	21,500	8,080,883
	Manitoba Zone										
5	Centra Gas (Manitoba)	871.86	69,300.4	60,420,260.7	71,805.0	62,603,907.3	887.84	228,361	202,748,030	242,787	215,556,010
6	Centra Gas Holdings Inc.	1002.24	2,376.0	2,381,337.3	10,981.0	11,005,597.4	1002.24	30,002	30,069,204	30,002	30,069,204
7	Gladstone-Austin Coop	798.14	101.4	80,911.4	205.0	163,618.7	798.14	863	688,795	863	688,795
8	Total Zone Firm Service	888.93	71,777.8	62,882,509.4	82,991.0	73,773,123.4	900.10	259,226	233,506,029	273,652	246,314,009
	Welwyn to Manitoba Zone										
9	Centra Gas (Manitoba)	277.34	5,597.6	1,552,446.1	15,286.0	4,239,419.2	288.51	16,829	4,855,335	41,764	12,049,332
10	Total Zone Firm Service	277.34	5,597.6	1,552,446.1	15,286.0	4,239,419.2	288.51	16,829	4,855,335	41,764	12,049,332
	Western Zone										
11	Union Gas - WDA	1472.61	24,821.5	36,552,451.0	28,510.0	41,984,111.1	1503.31	92,246	138,674,334	77,896	117,101,836
12	Nipigon Power - WDA	1711.82	1,132.0	1,937,831.6	2,380.0	4,074,131.6	1711.82	6,502	11,130,254	6,502	11,130,254
13	Total Zone Firm Service	1491.04	25,953.6	38,490,282.6	30,890.0	46,058,242.7	1519.37	98,748	149,804,588	84,398	128,232,090
14	Less: Thunder Bay By-pass Adj.		-	(87,794.2)	-	(150,495.9)		-	(438,548)	-	(411,166)
15	Total Zone Firm Service as Adj.	1486.17	25,953.6	38,402,488.4	30,890.0	45,907,746.8	1514.50	98,748	149,366,040	84,398	127,820,924
	Northern Zone										
16	Union Gas - NDA	2442.26	65,373.3	159,658,678.7	59,126.0	144,401,064.8	2451.06	199,252	488,378,607	161,547	395,961,390
17	Tunis Power	2302.96	1,492.8	3,437,785.0	2,758.0	6,351,563.7	2302.96	7,536	17,355,107	7,536	17,355,107
18	Gaz Métropolitain NDA	2541.75	5,519.2	14,028,513.0	5,610.0	14,259,217.5	2528.97	15,327	38,761,523	15,327	38,761,523
19	Union Gas - SSMDA	2168.75	18,735.4	40,632,500.7	20,060.0	43,505,125.0	2168.75	64,524	139,936,425	54,809	118,867,019
20	Total Zone Firm Service	2381.58	91,120.8	217,757,477.4	87,554.0	208,516,971.0	2386.70	286,639	684,431,662	239,219	570,945,039
21	Less: Thunder Bay By-pass Adj.		-	(3,540,929.9)	-	(3,233,659.1)		-	(10,865,373)	-	(8,835,142)
22	Total Zone Firm Service as Adj.	2344.65	91,120.8	214,216,547.5	87,554.0	205,283,311.9	2349.77	286,639	673,566,289	239,219	562,109,897

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SUMMARY OF ALLOCATION UNITS AS ADJUSTED

		VARIABLE ALLOCATION UNITS					FIXED ALLOCATION UNITS				
		KM	BASE YEAR ENDED DEC. 31, 2002		TEST YEAR ENDING DEC. 31, 2004		KM	BASE YEAR ENDED DEC. 31, 2002		TEST YEAR ENDING DEC. 31, 2004	
LINE NO.	PARTICULARS	LOAD CENTRE	TJ	TJ-km	TJ	TJ-km	LOAD CENTRE	GJ	GJ-km	GJ	GJ-km
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Eastern Zone										
1	Union Gas - NCDA	2813.69	4,002.3	11,261,315.9	4,040.0	11,367,307.6	2815.14	11,039	31,076,330	11,039	31,076,330
2	Enbridge Gas - CDA	2994.72	165,678.2	496,159,735.3	40,352.0	120,842,941.4	2997.02	546,551	1,638,024,278	110,250	330,421,455
3	Union Gas - CDA	3004.00	64,861.2	194,842,945.7	89,098.0	267,650,392.0	3022.71	176,121	532,362,708	243,436	735,836,432
4	Enbridge Gas - EDA	3073.13	111,438.6	342,465,215.7	47,486.0	145,930,651.2	3072.01	288,279	885,595,971	129,744	398,574,865
5	Union Gas - EDA	3222.20	49,151.0	158,374,300.6	57,365.0	184,841,503.0	3220.42	156,578	504,246,923	156,735	504,752,529
6	Kingston PUC - EDA	3207.71	3,226.3	10,349,005.9	3,950.0	12,670,454.5	3207.71	10,793	34,620,814	10,793	34,620,814
7	Gaz Métropolitain - EDA	3537.48	161,518.5	571,368,445.7	180,983.0	640,223,742.8	3529.79	588,089	2,075,830,671	494,489	1,745,442,327
8	Enhanced Capacity Release	1906.92	4,598.0	8,768,018.2	0.0	0.0	1906.92	0	0	0	0
9	Total Zone Firm Service	3268.63	564,474.0	1,793,588,983.0	423,274.0	1,383,526,992.5	3269.15	1,777,450	5,701,757,695	1,156,486	3,780,724,752
10	Less: Thunder Bay By-pass Adj.		-	(18,367,501.8)	-	(17,537,491.1)		-	(67,201,779)	-	(47,916,596)
11	Less: Union Transportation Adj.		-	(41,276,008.1)	-	(13,334,171.0)		-	(90,359,939)	-	(36,432,171)
12	Less: North Bay Shortcut Adj.		-	(58,186,731.3)	-	(43,727,985.1)		-	(199,573,321)	-	(119,475,456)
13	Less: Winchester Shortcut Adj.			(6,800,274.5)		(7,081,125.2)			(23,324,102)		(19,347,351)
14	Total Zone Firm Service as Adj.	3075.66	564,474.0	1,668,958,467.3	423,274.0	1,301,846,220.1	3076.17	1,777,450	5,321,298,554	1,156,486	3,557,553,178
	Herbert to Eastern Zone										
15	Gaz Métropolitain - EDA	3075.91	0.0	0.0	4,575.0	14,072,265.4	3076.43	0	0	12,500	38,455,313
16	Less: Thunder Bay By-pass Adj.		-	0.0	-	(189,557.2)		-	0	-	(517,911)
17	Less: Union Transportation Adj.		-	0.0	-	(144,123.7)		-	0	-	(393,781)
18	Less: North Bay Shortcut Adj.		-	0.0	-	(472,654.6)		-	0	-	(1,291,406)
19	Less: Winchester Shortcut Adj.			0.0		(76,539.7)			0		(209,125)
20	Total Zone Firm Service as Adj.	2882.93	0.0	0.0	4,575.0	13,189,390.2	2883.45	0	0	12500	36,043,090
	Bayhurst to Eastern Zone										
21	Gaz Métropolitain - EDA	3238.28	0.0	0.0	915.0	2,963,022.5	3238.80	0	0	2,500	8,096,990
22	Less: Thunder Bay By-pass Adj.		-	0.0	-	(37,911.4)		-	0	-	(103,582)
23	Less: Union Transportation Adj.		-	0.0	-	(28,824.7)		-	0	-	(78,756)
24	Less: North Bay Shortcut Adj.		-	0.0	-	(94,530.9)		-	0	-	(258,281)
25	Less: Winchester Shortcut Adj.			0.0		(15,307.9)			0		(41,825)
26	Total Zone Firm Service as Adj.	3045.30	0.0	0.0	915.0	2,786,447.6	3045.82	0	0	2500	7,614,546
	Southwest Zone										
27	Enbridge - SWDA	2613.37	0.0	0.0	0.0	0.0	2613.37	0	0	0	0
28	Union - SWDA	2594.41	0.0	0.0	0.0	0.0	2597.32	0	0	0	0
29	Total Zone Firm Service	2603.41	0.0	0.0	0.0	0.0	2598.14	0	0	0	0
30	**Dawn to Enbridge Gas - CDA**	300.59	0.0	0.0	79,758.0	23,974,457.2	303.90	0	0	217,917	66,224,976
31	**Dawn to Enbridge Gas - EDA**	696.06	0.0	0.0	41,779.0	29,080,690.7	693.96	0	0	114,150	79,215,534
32	**Dawn to Union Gas - CDA**	227.71	0.0	0.0	54,105.0	12,320,249.6	232.53	0	0	147,828	34,374,445
33	**Dawn to Union Gas - EDA**	551.22	0.0	0.0	553.0	304,824.7	550.10	0	0	1,510	830,651
34	**St. Clair to Union Gas - SWDA**	4.87	1,654.3	8,056.3	74,757.0	364,066.6	7.78	14,000	108,920	204,256	1,589,112
35	**Dawn to Gaz Métropolitain - EDA**	860.46	0.0	0.0	25,620.0	22,044,985.2	844.13	0	0	70,000	59,089,100
36	Total Canadian Firm Service as Adj.		772,245.2	1,992,254,526.5	1,019,744.0	1,784,965,942.5		2,486,967	6,402,287,405	2,835,229	4,939,661,622

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SUMMARY OF ALLOCATION UNITS AS ADJUSTED

LINE NO.	PARTICULARS	VARIABLE ALLOCATION UNITS KM LOAD CENTRE	BASE YEAR ENDED DEC. 31, 2002 TJ	BASE YEAR ENDED DEC. 31, 2002 TJ-km	TEST YEAR ENDING DEC. 31, 2004 TJ	TEST YEAR ENDING DEC. 31, 2004 TJ-km	FIXED ALLOCATION UNITS KM LOAD CENTRE	BASE YEAR ENDED DEC. 31, 2002 GJ	BASE YEAR ENDED DEC. 31, 2002 GJ-km	TEST YEAR ENDING DEC. 31, 2004 GJ	TEST YEAR ENDING DEC. 31, 2004 GJ-km
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	EXPORT FIRM SERVICE										
1	**Herbert to Emerson**	830.62	943.1	783,341.1	0.0	0.0	830.62	37,741	31,348,429	0	0
2	**Empress to Spruce**	1002.24	2,712.0	2,718,120.0	2,124.0	2,128,757.8	1002.24	28,357	28,420,520	5,803	5,815,999
3	**Empress to Emerson**	1023.34	44,060.2	45,088,519.0	278,003.0	284,491,590.0	1023.34	556,075	569,053,791	759,570	777,298,364
4	**Empress to St. Clair**	2589.64	15,859.0	41,069,043.8	27,344.0	70,811,116.2	2589.64	74,710	193,472,004	74,710	193,472,004
	Herbert to Niagara Falls	2954.40	979.3	2,893,300.1	0.0	0.0	2954.40	7,717	22,799,105	0	0
5	Less: Thunder Bay By-pass Adj.		-	(5,112.8)	-	0.0		-	(142,106)	-	0
6	Less: Union Transportation Adj.		-	(195,820.7)	-	0.0		-	(1,077,128)	-	0
7	Total Firm Service as Adjusted	2849.00	979.3	2,692,366.6	0.0	0.0	2849.00	7,717	21,579,871	0	0
	Empress to Chippawa	3149.52	25,232.5	79,470,191.0	46,058.0	145,060,592.2	3149.52	125,841	396,338,746	125,841	396,338,746
8	Less: Thunder Bay By-pass Adj.		-	(131,699.9)	-	(1,531,491.7)		-	(2,317,284)	-	(4,184,391)
9	Less: Union Transportation Adj.		-	(5,045,384.4)	-	(3,283,628.5)		-	(17,564,702)	-	(8,971,658)
10	Total Firm Service as Adjusted	3044.98	25,232.5	74,293,106.7	46,058.0	140,245,472.0	3044.97	125,841	376,456,760	125,841	383,182,697
	Empress to Niagara Falls	3147.13	191,895.3	603,919,571.9	254,650.0	801,416,654.5	3147.13	886,607	2,790,267,488	695,764	2,189,659,757
11	Enhanced Capacity Release	1347.82	619.8	835,408.5		0.0	1347.82				
12	Less: Thunder Bay By-pass Adj.		-	(974,556.5)	-	(8,467,454.3)		-	(16,326,456)	-	(23,135,031)
13	Less: Union Transportation Adj.		-	(38,494,556.3)	-	(18,154,848.2)		-	(123,751,314)	-	(49,603,522)
14	Total Firm Service as Adjusted	3042.59	192,515.2	565,285,867.6	254,650.0	774,794,352.0	3042.59	886,607	2,650,189,718	695,764	2,116,921,204
	Empress to Iroquois	3330.56	177,264.9	590,391,288.8	323,508.0	1,077,462,804.5	3330.56	893,840	2,976,987,750	883,901	2,943,885,315
15	Less: Winchester Shortcut Adj.			(46,510,764.5)		(84,882,029.0)			(234,525,739)		(231,917,944)
16	2002 Distance via Winchester	3068.18		543,880,524.3	323,508.0	992,580,775.5	3068.18		2,742,462,011	883,901	2,711,967,371
17	Less: Thunder Bay By-pass Adj.		-	(8,671,404.0)	-	(15,499,371.7)		-	(43,724,669)	-	(42,347,979)
18	Less: Union Transportation Adj.		-	0.0	-	0.0		-	0	-	0
19	Less: North Bay Shortcut Adj.		-	0.0	-	0.0		-	0	-	0
20	Total Firm Service as Adjusted	3020.27	177,264.9	535,209,120.3	323,508.0	977,081,403.8	3020.27	893,840	2,698,737,342	883,901	2,669,619,392
	Empress to Cornwall	3369.88	9,468.1	31,906,458.6	13,232.0	44,590,252.2	3369.88	27,233	91,771,942	36,154	121,834,642
21	Less: Thunder Bay By-pass Adj.		-	(413,924.1)	-	(580,606.0)		-	(1,233,315)	-	(1,586,407)
22	Less: Union Transportation Adj.		-	(225,296.2)	-	(259,422.2)		-	(452,374)	-	(708,801)
23	Less: North Bay Shortcut Adj.		-	(2,019,373.1)	-	(2,229,702.5)		-	(5,808,285)	-	(6,092,251)
24	Less: Winchester Shortcut Adj.		-	(236,003.1)	-	(361,068.6)		-	(678,813)	-	(986,553)
25	Total Firm Service as Adjusted	3110.60	9,468.1	29,011,862.1	13,232.0	41,159,452.9	3110.60	27,233	83,599,156	36,154	112,460,630
	Empress to Philipsburg	3544.16	6,054.2	21,457,081.8	10,191.0	36,118,534.6	3544.16	27,843	98,680,047	27,843	98,680,047
26	Less: Thunder Bay By-pass Adj.		-	(264,674.9)	-	(447,171.0)		-	(1,260,954)	-	(1,221,761)
27	Less: Union Transportation Adj.		-	(144,069.9)	-	(199,799.6)		-	(462,424)	-	(545,824)
28	Less: North Bay Shortcut Adj.		-	(1,291,248.2)	-	(1,717,268.6)		-	(5,938,386)	-	(4,691,778)
29	Less: Winchester Shortcut Adj.		-	(150,907.8)		(278,087.2)			(694,018)		(759,767)
30	Total Firm Service as Adjusted	3284.88	6,054.2	19,606,181.0	10,191.0	33,476,208.2	3284.88	27,843	90,324,265	27,843	91,460,917

TransCanada
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SUMMARY OF ALLOCATION UNITS AS ADJUSTED

		VARIABLE ALLOCATION UNITS					FIXED ALLOCATION UNITS				
		KM	BASE YEAR ENDED DEC. 31, 2002		TEST YEAR ENDING DEC. 31, 2004		KM	BASE YEAR ENDED DEC. 31, 2002		TEST YEAR ENDING DEC. 31, 2004	
LINE NO.	PARTICULARS	LOAD CENTRE	TJ	TJ-km	TJ	TJ-km	LOAD CENTRE	GJ	GJ-km	GJ	GJ-km
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Steelman to Philipsburg	3160.21	346.0	1,093,451.6	844.0	2,667,217.2	3160.21	2,306	7,287,444	2,306	7,287,444
1	Less: Thunder Bay By-pass Adj.		-	(15,130.6)	-	(37,034.7)		-	(104,439)	-	(101,187)
2	Less: Union Transportation Adj.		-	(8,219.4)	-	(16,547.2)		-	(38,245)	-	(45,200)
3	Less: North Bay Shortcut Adj.		-	(73,796.5)	-	(142,221.1)		-	(491,826)	-	(388,580)
4	Less: Winchester Shortcut Adj.		-	(8,624.4)		(23,030.7)			(57,480)		(62,925)
5	Total Firm Service as Adjusted	2900.93	346.0	987,680.7	844.0	2,448,383.5	2900.93	2,306	6,595,454	2,306	6,689,552
	Empress to Napierville	3526.70	10,079.7	35,547,933.4	23,853.0	84,122,375.1	3526.70	65,173	229,845,619	65,173	229,845,619
6	Less: Thunder Bay By-pass Adj.		-	(440,659.1)	-	(1,046,648.8)		-	(2,951,552)	-	(2,859,719)
7	Less: Union Transportation Adj.		-	(239,839.0)	-	(467,655.8)		-	(1,082,571)	-	(1,277,795)
8	Less: North Bay Shortcut Adj.		-	(2,149,800.9)	-	(4,019,429.7)		-	(13,900,170)	-	(10,982,195)
9	Less: Winchester Shortcut Adj.		-	(251,247.9)	-	(650,889.6)		-	(1,624,511)	-	(1,778,410)
10	Total Firm Service as Adjusted	3267.42	10,079.7	32,466,386.5	23,853.0	77,937,751.2	3267.42	65,173	210,286,815	65,173	212,947,500
	Empress to East Hereford	3729.12	27,150.3	101,246,685.7	34,852.0	129,967,290.2	3729.12	95,223	355,097,994	95,223	355,097,994
11	Less: Thunder Bay By-pass Adj.			(1,186,950.3)		(1,529,273.4)			(4,312,445)		(4,178,307)
12	Less: Union Transportation Adj.			(646,035.6)		(683,296.7)			(1,581,704)		(1,866,966)
13	Less: North Bay Shortcut Adj.			(5,790,643.8)		(5,872,853.1)			(20,309,267)		(16,045,871)
14	Less: Winchester Shortcut Adj.			(676,751.9)		(951,025.0)			(2,373,541)		(2,598,401)
15	Total Firm Service as Adjusted	3469.84	27,150.3	92,946,304.1	34,852.0	120,930,842.0	3469.84	95,223	326,521,037	95,223	330,408,449
16	**St. Clair to Chippawa**	326.86	68,094.9	22,257,508.2	79,887.0	26,111,864.8	326.86	319,548	104,447,459	319,548	104,447,459
17	**Kirkwall to Chippawa**	114.37	2,060.7	235,682.0	14,426.0	1,649,901.6	114.37	41,491	4,745,326	41,491	4,745,326
18	**St. Clair to East Hereford**	1075.93	21,761.6	23,413,966.9	24,515.0	26,376,424.0	1075.93	115,802	124,594,846	115,802	124,594,846
19	**Dawn to Iroquois**	653.54	0.0	0.0	23,790.0	15,547,740.4	653.54	0	0	65,000	42,480,165
20	**Dawn to Niagara**	300.65	6,125.1	1,841,498.7	73,200.0	22,007,580.0	300.65	33,425	10,049,226	200,000	60,130,000
21	Total Export Firm Service as Adj.		610,706.7	1,489,906,555.3	1,230,477.0	2,617,198,840.4		3,338,932	7,530,422,018	3,514,129	7,236,674,504
22	Total System Firm Service as Adj.		1,382,951.8	3,482,161,081.8	2,250,221.0	4,402,164,782.9		5,825,899	13,932,709,423	6,349,358	12,176,336,126

TransCanada
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GLGT/UNION TRANSPORTATION ADJUSTMENT
BASE YEAR ENDED DEC. 31, 2002

LINE NO.	PARTICULARS	VARIABLE ALLOCATION UNITS TJ	TJ	TJ-km	FIXED ALLOCATION UNITS GJ	GJ	GJ-km
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Great Lakes Route		423,090			1,398,780	
2	Northern Route		709,386			2,888,123	
3	Total Downstream of Manitoba Zone		1,132,476			4,286,903	
4	Great Lakes Route		423,090			1,398,780	
5	Sault Ste. Marie Firm Transportation		(18,735)			(64,524)	
6	St. Clair Firm Transportation		(15,859)			(74,710)	
7	Southwestern Delivery Area		(3,064)			(203,570.0)	
8	Union Transportation		385,431			1,055,976	
9	Parkway 156.59 km		46,246	7,241,708		126,702	19,840,266
10	Kirkwall 233.01 km		339,185	79,033,522		929,274	216,530,135
11	Union Transportation Adjustment		385,431	86,275,230		1,055,976	236,370,401
12	Eastern Zone Firm Transportation (FT)	206,425.5	184,399	41,276,008	647,377	403,680	90,359,939
13	Empress to Niagara Falls FT	192,515.2	171,973	38,494,556	886,607	552,854	123,751,314
14	Herbert to Niagara Falls FT	979.3	875	195,821	7,717	4,812	1,077,128
15	Empress to Cornwall FT	1,126.7	1,007	225,296	3,241	2,021	452,374
16	Empress to Philipsburg FT	720.5	644	144,070	3,313	2,066	462,424
17	Steelman to Philipsburg FT	41.1	37	8,219	274	171	38,245
18	Empress to Napierville FT	1,199.5	1,072	239,839	7,756	4,836	1,082,571
19	Empress to East Hereford FT	3,230.9	2,886	646,036	11,332.0	7,066	1,581,704
20	Empress to Chippawa FT	25,232.5	22,540	5,045,384	125,841	78,470	17,564,702
21	Total	431,471.1	385,431 (1)	86,275,230 (1)	1,693,458	1,055,976 (2)	236,370,401 (2)

Notes: (1) Pro-rated on basis of column (b)
(2) Pro-rated on basis of column (e)

TransCanada
In business to deliver

GLGT/UNION TRANSPORTATION ADJUSTMENT
TEST YEAR ENDING DEC. 31, 2004

LINE NO.	PARTICULARS			VARIABLE ALLOCATION UNITS TJ	TJ	TJ-km	FIXED ALLOCATION UNITS GJ	GJ	GJ-km
	(a)			(b)	(c)	(d)	(e)	(f)	(g)
1	Great Lakes Route				258,945			719,825	
2	Northern Route				995,451			2,767,193	
3	Total Downstream of Manitoba Zone				1,254,396			3,487,018	
4	Great Lakes Route				258,945			719,825	
5	Sault Ste. Marie Firm Transportation				(20,060)			(54,809)	
6	St. Clair Firm Transportation				(27,344)			(74,710)	
7	Southwestern Delivery Area				(54,585)			(161,464.0)	
8	Union Transportation				156,956			428,842	
9	Parkway	156.59	km		0	0		0	0
10	Kirkwall	233.01	km		156,956	36,572,318		428,842	99,924,474
11	Union Transportation Adjustment				156,956	36,572,318		428,842	99,924,474
12	Eastern Zone Firm Transportation (FT)			187,032.5	57,226	13,334,171	511,016	156,355	36,432,171
13	Herbert to Eastern Zone FT			2,021.6	619	144,124	5,523	1,690	393,781
14	Bayhurst to Eastern Zone FT			404.3	124	28,825	1,105	338	78,756
15	Empress to Niagara Falls FT			254,650.0	77,915	18,154,848	695,764	212,882	49,603,522
16	Empress to Cornwall FT			3,638.8	1,113	259,422	9,942	3,042	708,801
17	Empress to Philipsburg FT			2,802.5	858	199,800	7,656	2,342	545,824
18	Steelman to Philipsburg FT			232.1	71	16,547	634	194	45,200
19	Empress to Napierville FT			6,559.6	2,007	467,656	17,923	5,484	1,277,795
20	Empress to East Hereford FT			9,584.3	2,933	683,297	26,187.0	8,012	1,866,966
21	Empress to Chippawa FT			46,058.0	14,092	3,283,629	125,841	38,503	8,971,658
22	Total			512,983.7	156,956 (1)	36,572,318 (1)	1,401,591	428,842 (2)	99,924,474 (2)

Notes: (1) Pro-rated on basis of column (b)
(2) Pro-rated on basis of column (e)

TransCanada
In business to deliver

THUNDER BAY BYPASS ADJUSTMENT
BASE YEAR ENDED DEC. 31, 2002
TEST YEAR ENDING DEC. 31, 2004

LINE NO.	PARTICULARS	VARIABLE UNITS TJ	VARIABLE UNITS TJ-km	FIXED UNITS GJ	FIXED UNITS GJ-km
	(a)	(b)	(c)	(d)	(e)
	BASE YEAR ADJUSTMENT (7)				
1	Western Zone Firm Transportation (FT)	1,794.7	87,794	8,965	438,548
2	Northern Zone FT	72,385.3	3,540,930	222,115	10,865,373
3	Eastern Zone FT	375,477.0	18,367,502	1,373,770	67,201,779
4	Empress to Niagara Falls FT	19,922.3	974,557	333,753	16,326,456
5	Herbert to Niagara Falls FT	104.5	5,113	2,905	142,106
6	Empress to Iroquois FT	177,264.9	8,671,404	893,840	43,724,669
7	Empress to Cornwall FT	8,461.6	413,924	25,212	1,233,315
8	Empress to Philipsburg FT	5,410.6	264,675	25,777	1,260,954
9	Steelman to Philipsburg FT	309.3	15,131	2,135	104,439
10	Empress to Napierville FT	9,008.2	440,659	60,337	2,951,552
11	Empress to East Hereford FT	24,264.2	1,186,950	88,157	4,312,445
12	Empress to Chippawa FT	2,692.3	131,700	47,371	2,317,284
13	Total	697,095.0 (1)	34,100,338 (3)	3,084,337 (2)	150,878,919 (4)
	TEST YEAR ADJUSTMENT (7)				
14	Western Zone Firm Transportation (FT)	3,141.2	150,495.9	8,582	411,166
15	Northern Zone FT	67,494.0	3,233,659	184,410	8,835,142
16	Eastern Zone FT	366,048.3	17,537,491	1,000,131	47,916,596
17	Herbert to Eastern Zone FT	3,956.5	189,557	10,810	517,911
18	Bayhurst to Eastern Zone FT	791.3	37,911	2,162	103,582
19	Empress to Niagara Falls FT	176,735.5	8,467,454	482,882	23,135,031
20	Empress to Iroquois FT	323,508.0	15,499,372	883,901	42,347,979
21	Empress to Cornwall FT	12,118.6	580,606	33,112	1,586,407
22	Empress to Philipsburg FT	9,333.5	447,171	25,501	1,221,761
23	Steelman to Philipsburg FT	773.0	37,035	2,112	101,187
24	Empress to Napierville FT	21,846.0	1,046,649	59,689	2,859,719
25	Empress to East Hereford FT	31,919.5	1,529,273	87,211	4,178,307
26	Empress to Chippawa FT	31,965.8	1,531,492	87,338	4,184,391
27	Total	1,049,631.2 (1)	50,288,166 (5)	2,867,841 (2)	137,399,179 (6)

Notes:

(1) Total Firm Transportation delivered downstream of the Thunder Bay ByPass, via the Northern Route
(2) Fixed Volumes attributable to Firm Transportation delivered downstream of the Thunder Bay ByPass, via the Northern Route
(3) Deliveries through the Thunder Bay ByPass x distance saved, (609,261.0 TJ x 55.97 km), pro-rated based on column (b)
(4) Based on variable units (609,261.0 / 697,095.0 x 3,084,337 x 55.97 km), pro-rated based on column (d)
(5) Deliveries projected through the Thunder Bay ByPass x distances saved, (898,484.3 TJ x 55.97 km), prorated based on column (b)
(6) Based on variable units (898,484.3 / 1,049,631.2 x 2,867,841 x 55.97 km), pro-rated based on column (d)
(7) 87.4% of base year, and 85.6% of test year deliveries downstream of the ByPass flow through the shortcut

Illustrative Example, Fixed Units, Test Year

Distance savings associated with the Thunder Bay ByPass	55.97	km
Firm Transportation deliveried through Thunder Bay and the ByPass	2,867,841	GJ
Percentage of these FT deliveries through the by-pass	85.6	%
Total ByPass credits available (55.97km x 2867841GJ x 85.6%)	137,399,179	GJ-km
Credits are shared among delivery points in proportion to the deliveries		
e.g. credit for the Western Zone (column e, row 15)		
= (8582 GJ / 2867841 GJ) x 137399179 GJ-km	411,166	GJ-km

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NORTH BAY SHORTCUT ADJUSTMENT
BASE YEAR ENDED DEC. 31, 2002
TEST YEAR ENDING DEC. 31, 2004

		VARIABLE UNITS		FIXED UNITS	
LINE NO.	PARTICULARS	TJ	TJ-km	GJ	GJ-km
	(a)	(b)	(c)	(d)	(e)
	BASE YEAR ADJUSTMENT (7)				
1	Eastern Zone Firm Transportation (FT)	272,817.1	58,186,731	935,729	199,573,321
2	Empress to Cornwall FT	9,468.1	2,019,373	27,233	5,808,285
3	Empress to Philipsburg FT	6,054.2	1,291,248	27,843	5,938,386
4	Steelman to Philipsburg FT	346.0	73,797	2,306	491,826
5	Empress to East Hereford FT	27,150.3	5,790,644	95,223	20,309,267
6	Empress to Napierville FT	10,079.7	2,149,801	65,173	13,900,170
7	Total	325,915.4 (1)	69,511,594 (3)	1,153,507 (2)	246,021,255 (4)
	TEST YEAR ADJUSTMENT (7)				
8	Eastern Zone Firm Transportation (FT)	259,500.4	43,727,985	709,018	119,475,456
9	Herbert to Eastern Zone FT	2,804.9	472,655	7,664	1,291,406
10	Bayhurst to Eastern Zone FT	561.0	94,531	1,533	258,281
11	Empress to Cornwall FT	13,232.0	2,229,703	36,154	6,092,251
12	Empress to Philipsburg FT	10,191.0	1,717,269	27,843	4,691,778
13	Steelman to Philipsburg FT	844.0	142,221	2,306	388,580
14	Empress to East Hereford FT	34,852.0	5,872,853	95,223	16,045,871
15	Empress to Napierville FT	23,853.0	4,019,430	65,173	10,982,195
16	Total	345,838.3 (1)	58,276,646 (5)	944,914 (2)	159,225,818 (6)

Notes:
(1) Total Firm Transportation delivered downstream of Station 130 via the Northern Route.
(2) Fixed Volumes attributable to Firm Transportation delivered downstream of Station 130 via the Northern Route.
(3) Deliveries through the North Bay Shortcut x distance saved, (256,169.5 TJ x 271.35 km), prorated based on column (b)
(4) Deliveries projected through the North Bay Shortcut x distance saved, (214,765.6 TJ x 271.35 km), prorated based on column (b)
(5) Based on variable units (214,765.6/ 345,838.3 x 944,914 x 271.35 km), pro-rated based on column (d)
(6) Volumes through the shortcut, 78.6'% of base year, and 62.1% of test year deliveries

Illustrative Example, Fixed Units, Test Year

Distance savings associated with the North Bay Shortcut	271.35	km
Firm Transportation deliveried down stream of Stn 130 via Northern route	944,914	GJ
Percentage of these FT deliveries through the shortcut	62.1	%
Total credits available (271.35km x 944913.5GJ x 62.1%)	159,225,818	GJ-km
Credits are shared among delivery points in proportion to the deliveries		
e.g. credit for the Eastern Zone (column e, row 18)		
= (709018 GJ / 944913.5 GJ) x 159225818 GJ-km	119,475,456	GJ-km

TransCanada
In business to deliver

WINCHESTER SHORTCUT ADJUSTMENT
BASE YEAR ENDED DEC. 31, 2002
TEST YEAR ENDING DEC. 31, 2004

LINE NO.	PARTICULARS	VARIABLE UNITS TJ	VARIABLE UNITS TJ-km	FIXED UNITS GJ	FIXED UNITS GJ-km
	(a)	(b)	(c)	(d)	(e)
	BASE YEAR ADJUSTMENT				
	Winchester Shortcut Flow to Iroquois				
1	Empress to Iroquois FT	177,264.9	46,510,765	893,840	234,525,739
		177,264.9	46,510,765	893,840	234,525,739
	Flow of Winchester Shortcut to Montreal Line				
2	Eastern Zone Firm Transportation (FT)	272,817.1	6,800,275	935,729	23,324,102
3	Empress to Cornwall FT	9,468.1	236,003	27,233	678,813
4	Empress to Philipsburg FT	6,054.2	150,908	27,843	694,018
5	Steelman to Philipsburg FT	346.0	8,624	2,306	57,480
6	Empress to East Hereford FT	27,150.3	676,752	95,223	2,373,541
7	Empress to Napierville FT	10,079.7	251,248	65,173	1,624,511
8	Total	325,915.4	8,123,810	1,153,507	28,752,465
9	Total WSC Distance Credits	503,180.3	54,634,574	2,047,347	263,278,204
	TEST YEAR ADJUSTMENT (3)				
	Winchester Shortcut Flow to Iroquois				
10	Empress to Iroquois FT	323,508.0	84,882,029	883,901	231,917,944
11	WSC Flow to Iroquois Total	323,508.0	84,882,029	883,901	231,917,944
	Flow of Winchester Shortcut to Montreal Line				
12	Eastern Zone Firm Transportation (FT)	259,500.4	7,081,125	709,018	19,347,351
13	Herbert to Eastern Zone FT	2,804.9	76,539.7	7,664	209,125
14	Bayhurst to Eastern Zone FT	561.0	15,307.9	1,533	41,825
15	Empress to Cornwall FT	13,232.0	361,068.6	36,154	986,553
16	Empress to Philipsburg FT	10,191.0	278,087.2	27,843	759,767
17	Steelman to Philipsburg FT	844.0	23,030.7	2,306	62,925
18	Empress to East Hereford FT	34,852.0	951,025.0	95,223	2,598,401
19	Empress to Napierville FT	23,853.0	650,890	65,173	1,778,410
20	WSC Flow to Montreal Line Total	345,838.3	9,437,074 (1)	944,914	25,784,357 (2)
21	Total WSC Distance Credits	669,346.3	94,319,103	1,828,815	257,702,301

Notes:

(1) Deliveries projected through the North Bay Shortcut x distance saved, (35,967.2 TJ x 262.38 km), pro-rated based on column (b)
(2) Based on variable units (35,967.2/ 1,828,814.5 x 1,828,815 x km), pro-rated based on column (d)
(3) 9.5% of base year, and 10.4% of test year deliveries downstream of the shortcut flow through the shortcut

Illustrative Example, Fixed Units, Test Year

Distance savings associated with the Winchestor Shortcut	262.38	km
Firm Transportation deliveried down stream of Stn 130 via Northern route	944,914	GJ
Percentage of these FT deliveries through the shortcut	10.4	%
Total credits available (262.38km x 944913.5GJ x 10.4%)	25,784,357	GJ-km
Credits are shared among delivery points in proportion to the deliveries		
e.g. credit for the Eastern Zone (column e, row 13)		
= (709018 GJ / 944913.5 GJ) x 25784357 GJ-km	19,347,351	GJ-km

FUNCTIONAL DISTRIBUTION AND CLASSIFICATION OF COST OF SERVICE, RATE BASE AND RETURN

Schedule 2.1

The Cost of Service refers to the annual owning and operating costs of TransCanada's Mainline system. For the purpose of determining the design of Canadian and export tolls, the total cost of service is first divided into two functions:

(a) Metering; and

(b) Transmission (Fixed and Variable).

This functional separation of costs is shown in Schedule 2.1.

The functional separation of certain costs is determined on the basis of the functionalization of rate base. Rate base is functionalized between metering and transmission based on the percentage of metering assets and the remaining assets to total rate base assets.

The Mainline's costs are directly identifiable with the metering and transmission functions. The Mainline's costs are functionalized in the following manner:

(i) **Transmission By Others:** TBO Costs are allocated to Transmission-Fixed and Transmission-Variable based on the corresponding demand and commodity rates of the TBO service provider.

(ii) **Operation & Maintenance:** The 2004 Test Year O&M cost, for toll making purposes, is $258.208M. This represents the consolidation of the following cost categories in Tab Revenue Requirement, Schedule 1.3:

Operations, Maintenance & Administrative Expense: Field Operations and Maintenance Salaries are allocated between Metering and Transmission on the basis of Total Plant. Administrative and

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General Expenses are allocated 50% to Metering (GJ) and 50% to Transmission-Fixed (GJ-km).

Inventory Management Program: This cost is classified as Fixed Transmission.

Pipeline Integrity & Insurance Deductible Costs: This cost is classified as Fixed Transmission.

Regulatory Proceeding Costs: This cost is classified as Fixed Transmission.

(iii) **Municipal & Provincial Capital Taxes:** Municipal Taxes are allocated between Metering and Transmission on the basis of total plant. Provincial Capital Taxes are allocated to Transmission-Fixed.

(iv) **Delivery Pressure on TBO:** This cost is classified as Fixed Transmission.

(v) **Gas Related and Electric Costs:** The forecast minimum monthly charge for electric costs has been classified as Fixed Transmission. The remainder of this cost is classified as Variable Transmission.

(vi) **Storage Operating Costs:** These costs are functionalized based on the corresponding demand and commodity rates of the storage providers.

(vii) **Depreciation:** Depreciation of general plant is assigned to the Fixed Transmission and Metering functions on the basis of gross plant. The remaining depreciation amount is assigned by asset class to the Fixed Transmission and Metering functions.

(viii) **Income Taxes:** This cost is assigned on the basis of the functionalization of rate base, as set out in Schedule 2.1.

(ix) **Regulatory Deferrals and Amortization:** All Regulatory Deferrals and Amortizations are classified as Fixed Transmission.

(x) **NEB Cost Recovery Expense:** NEB Cost Recovery Expense is allocated 50% to Metering (GJ) and 50% to Transmission-Fixed (GJ-km).

(xi) **Return:** This cost is assigned on the basis of the functionalization of rate base, as set out in Schedule 2.2.

(xii) **Miscellaneous Revenue:**

Miscellaneous Revenue has two categories of service: Non-Discretionary and Discretionary. The following is a brief description of the functionalization of Non-Discretionary and Discretionary Miscellaneous Revenue. For details of the calculations, please refer to the schedules under Tab 4, Toll Design.

Non-Discretionary Miscellaneous Revenue: This includes the revenue calculated for Sales Meter Station Charges, Storage Transportation Service, Sale of Delivery Pressure and Long Term Winter Firm Service. The commodity revenue, where applicable, is determined by applying the variable energy-distance system average unit cost to the appropriate energy. The demand revenue, where applicable, is split between Fixed Transmission and Metering functions based on each component's contribution to the demand toll.

Discretionary Miscellaneous Revenue: This includes the revenue projected for Interruptible Transportation, Short Term Firm Transportation, Diversions and other services. The revenue is split between the Fixed Transmission and Metering functions based on a pro-rata share of the functional distribution of rate base.

Transmission function costs are further classified between fixed and variable components.

For the purpose of cost classification, fixed costs are defined as those costs which do not vary with changes in throughput. These costs are principally associated with the capital outlay necessary to provide the capacity of the pipeline system and operating costs which do not vary with increases or decreases in throughput. Fixed costs are allocated to Fixed Transmission and Metering. Variable costs are those which may vary with increases or decreases in throughput. These include Great Lakes/Union commodity charges, maintenance parts and related supplies, tax on fuel and electric costs.

Costs assigned to the metering and transmission functions are allocated on a Fixed Energy (GJ), Fixed Energy-Distance (GJ-km), or Variable Energy-Distance (TJ-km) basis.

Schedule 2.2

This schedule sets out the functional distribution of the rate base and return. For the most part, the functional cost distribution between metering and transmission is taken directly from plant records. Where joint costs are required to be distributed, this is performed on a gross plant basis.

FUNCTIONAL DISTRIBUTION AND CLASSIFICATION OF NET REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2004 ($000's)

LINE NO.	PARTICULARS	TOTAL	FIXED ENERGY	TRANSMISSION FIXED	TRANSMISSION VARIABLE
	(a)	(b)	(c)	(d)	(e)
1	Transmission by Others	355,397	0	346,493	8,904
2	Operation and Maintenance	258,208	77,662	148,519	32,027
3	Municipal and Other Taxes	118,772	925	117,847	0
4	Delivery Pressure on TBO	4,526	0	4,526	0
5	Gas Related and Electric Costs	67,277	0	27,600	39,677
6	Storage Operating costs	12,176	0	12,176	0
7	Depreciation	415,160	4,510	410,650	0
8	Income Taxes	217,412	1,869	215,543	0
9	Regulatory Deferrals & Amortizations	(68,526)	0	(68,526)	0
10	Debt Redemption costs	(41,601)	(358)	(41,243)	0
10	NEB Cost Recovery	12,785	6,393	6,393	0
11	Return	780,075	6,706	773,369	0
12	Gross Revenue Requirement	2,131,661	97,707	1,953,346	80,608
	NON-DISCRETIONARY MISCELLANEOUS REVENUE				
13	- Sales Meter Station Charges	(78)	(78)	0	0
14	- Storage Transportation Service	(40,493)	(10,421)	(29,614)	(458)
15	- Sale of Delivery Pressure	(28,629)	0	(27,992)	(637)
16	- Long Term Winter Firm Service	(1,336)	(41)	(1,251)	(44)
17	SUB-TOTAL NON-DISCRETIONARY	(70,536)	(10,540)	(58,858)	(1,138)
	DISCRETIONARY MISCELLANEOUS REVENUE				
18	- Miscellaneous Discretionary	(279,735)	(2,405)	(277,330)	0
19	SUB-TOTAL DISCRETIONARY	(279,735)	(2,405)	(277,330)	0
20	Total Miscellaneous Revenue	(350,271)	(12,945)	(336,188)	(1,138)
21	Net Revenue Requirement	1,781,390	84,762	1,617,158	79,470

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FUNCTIONAL DISTRIBUTION OF RATE BASE AND RETURN
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	TOTAL SYSTEM	METERING	TRANSMISSION
	(a)	(b)	(c)	(d)
	Utility Investment			
1	Gross Plant	12,389,333,000	113,202,111	12,276,130,889
2	Accumulated Depreciation	(4,308,622,000)	(41,105,254)	(4,267,516,746)
3	Net Plant	8,080,711,000	72,096,857	8,008,614,143
4	Less: Contributions in Aid of construction	(23,288,000)	(1,720,000)	(21,568,000)
5	Total Plant	8,057,423,000	70,376,857	7,987,046,143
	Working Capital			
6	Storage Gas	15,617,000	0	15,617,000
7	Cash	20,970,000	183,161	20,786,839
8	Goods and Services Tax	(4,531,000)	(39,576)	(4,491,424)
9	Materials and Supplies	28,932,000	0	28,932,000
10	Transmission Line Pack	42,834,000	0	42,834,000
11	Prepayments & Deposits	2,076,000	0	2,076,000
12	Total Working Capital	105,898,000	143,585	105,754,415
	Deferred Costs			
13	Miscellaneous Deferred Items	28,475,000	0	28,475,000
14	Operating and Debt Service Deferrals	(30,439,000)	0	(30,439,000)
15	Surplus Pension / Post Employment Benefits	41,325,000	0	41,325,000
16	Total Deferred Costs	39,361,000	0	39,361,000
17	Total Rate Base	8,202,682,000	70,520,442	8,132,161,558
18	Return calculated at 9.51 %	780,075,000	6,706,000	773,369,000

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FUNCTIONAL DISTRIBUTION OF UTILITY INVESTMENT IN GAS PLANT
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	TOTAL SYSTEM	METERING	TRANSMISSION
	(a)	(b)	(c)	(d)
1	Intangible Plant	8,567,000	78,285	8,488,715
	Transmission Plant			
2	Land	7,970,000	927,240	7,042,760
3	Land Rights	33,159,000	179,303	32,979,697
4	Compressor	3,297,897,000	0	3,297,897,000
5	Metering & Regulating	110,100,000	110,100,000	0
6	Mains	8,720,653,000	0	8,720,653,000
7	Communications	14,198,000	129,740	14,068,260
8	Total Transmission Plant	12,183,977,000	111,336,283	12,072,640,717
9	General Plant	192,980,000	1,763,437	191,216,563
	Gas Plant Under Construction			
10	Construction Warehouse	2,638,000	24,106	2,613,894
11	AFUDC and Amounts Capitalized	1,171,000	0	1,171,000
12	Total Gas Plant	12,389,333,000	113,202,111	12,276,130,889

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FUNCTIONAL DISTRIBUTION OF
ACCUMULATED DEPRECIATION AND AMORTIZATION
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	TOTAL SYSTEM	METERING	TRANSMISSION
	(a)	(b)	(c)	(d)
1	Intangible Plant	6,268,000	59,415	6,208,585
	Transmission Plant			
2	Land	0	0	0
3	Land Rights	12,382,000	66,954	12,315,046
4	Compressor	885,504,000	0	885,504,000
5	Metering & Regulating	40,125,000	40,125,000	0
6	Mains	3,302,061,000	0	3,302,061,000
7	Communication	10,019,000	94,971	9,924,029
8	Total Transmission Plant	4,250,091,000	40,286,925	4,209,804,075
9	General Plant	80,062,000	758,914	79,303,086
10	AFUDC and Amounts Capitalized	13,000	0	13,000
11	Retirement Work In Progress	(27,812,000)	0	(27,812,000)
12	Total Gas Plant	4,308,622,000	41,105,254	4,267,516,746

FUNCTIONAL DISTRIBUTION OF
CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	TOTAL SYSTEM	METERING	TRANSMISSION
	(a)	(b)	(c)	(d)
1	Intangible Plant	0	0	0
	Transmission Plant			
2	Land	0	0	0
3	Land Rights	0	0	0
4	Compressor	0	0	0
5	Metering & Regulating	1,720,000	1,720,000	0
6	Mains	21,568,000	0	21,568,000
7		23,288,000	1,720,000	21,568,000
8	General Plant	0	0	0
9	Total	23,288,000	1,720,000	21,568,000

CALCULATION OF PROPOSED TOLLS

TransCanada's proposed tolls have been calculated in a consistent manner employing the toll methodology approved by the Board in RH-1-2002. No changes to toll methodology are being proposed in this application.

Schedule 3.1

This schedule shows the allocation of Net Revenue Requirement to each domestic zone and export point. The zoned energy-distance method is used to determine the transmission cost of domestic service by zone. For export services, transmission costs are allocated based on the energy-distance method.

Unit costs are determined by dividing the respective system transmission costs by the appropriate system cost allocation units.

The allocation costs for domestic service and export service are determined by multiplying the system unit costs by the appropriate allocation units.

In summary, the functional costs are allocated as follows:

(a) Metering**:**	This cost is allocated to each fixed energy unit (GJ) of service.
(b) Transmission**:**	Cost of transmission is broken down between:
• **Fixed**	This cost is allocated to each fixed energy-distance (GJ-km) unit of service.
• **Variable**	This cost is allocated to each variable energy (GJ-km) unit of service.

Schedule 3.1 also shows the proposed Firm Transportation (FT) tolls. For each zone or export point, the fixed and variable allocated costs are divided by the respective fixed energy (GJ) and variable energy (GJ).

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Schedule 3.2

This schedule applies the proposed tolls to the allocation units for each domestic zone and export point. The resulting transmission revenues are then compared to the allocated transmission costs to ensure that the variances are inconsequential.

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DISTRIBUTION OF COST OF TRANSMISSION
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	FUNCTIONALIZED COST OF TRANSMISSION FIXED ($)	VARIABLE ($)	Total ($)	ALLOCATION BASE FIXED	VARIABLE	UNIT COST FIXED ($)	VARIABLE ($)
	(a)	(b)	(c)	(d)	(e) per year	(f) per day	(g) per year	(h) per day
	Cost							
1	Fixed Energy - ($/GJ)	84,762,088	0	84,762,088	6,349,358	0	13.3497100022	0.0000000000
2	Transmission - Variable - ($/GJ-km)	0	79,469,508	79,469,508	0	4,402,164,782,900	0.0000000000	0.0000180524
3	Transmission - Fixed - ($/GJ-km)	1,617,158,082	0	1,617,158,082	12,176,336,126	0	0.1328115506	0.0000000000
4	Total	1,701,920,170	79,469,508	1,781,389,678				

LINE NO.	PARTICULARS	COST ALLOCATION UNITS FIXED (GJ)	VARIABLE (GJ)	FIXED (GJ-km)	VARIABLE (GJ-km)	ALLOCATED COST FIXED Fixed Energy	Trans- Fixed	VARIABLE Trans - Variable	TOTAL ($)	ALLOCATED COST FIXED ($)	VARIABLE ($)	TOTAL ($)	PROPOSED TOLLS DEMAND ($/GJ/month)	COMMODITY ($/GJ)	AVERAGE ($/GJ)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	CANADIAN FIRM TRANSPORTATION														
5	Saskatchewan Zone	247,549	89,818,000	140,751,945	47,229,727,400	3,304,707	18,693,484	852,610	22,850,801	21,998,191	852,610	22,850,801	7.40533	0.00949	0.25295
6	Herbert to Saskatchewan Zone	21,500	7,869,000	8,080,883	2,621,281,900	287,019	1,073,235	47,320	1,407,574	1,360,254	47,320	1,407,574	5.27230	0.00601	0.17935
7	Manitoba Zone	273,652	82,991,000	246,314,009	73,773,123,400	3,653,175	32,713,345	1,331,782	37,698,302	36,366,520	1,331,782	37,698,302	11.07444	0.01605	0.38014
8	Welwyn to Manitoba Zone	41,764	15,286,000	12,049,332	4,239,419,200	557,537	1,600,290	76,532	2,234,359	2,157,827	76,532	2,234,359	4.30560	0.00501	0.14656
9	Western Zone	84,398	30,890,000	127,820,924	45,907,746,800	1,126,689	16,976,095	828,745	18,931,529	18,102,784	828,745	18,931,529	17.87442	0.02683	0.61448
10	Northern Zone	239,219	87,554,000	562,109,897	205,283,311,900	3,193,504	74,654,687	3,705,856	81,554,047	77,848,191	3,705,856	81,554,047	27.11887	0.04233	0.93391
11	Eastern Zone	1,156,486	423,274,000	3,557,553,178	1,301,846,220,100	15,438,753	472,484,155	23,501,318	511,424,226	487,922,908	23,501,318	511,424,226	35.15844	0.05552	1.21141
12	Herbert to Eastern Zone	12,500	4,575,000	36,043,090	13,189,390,200	166,871	4,786,939	238,100	5,191,910	4,953,810	238,100	5,191,910	33.02540	0.05204	1.13781
13	Bayhurst to Eastern Zone	2,500	915,000	7,614,546	2,786,447,600	33,374	1,011,300	50,302	1,094,976	1,044,674	50,302	1,094,976	34.82247	0.05497	1.19982
14	Dawn to Enbridge Gas - CDA	217,917	79,758,000	66,224,976	23,974,457,200	2,909,129	8,795,442	432,796	12,137,367	11,704,571	432,796	12,137,367	4.47593	0.00543	0.15258
15	Dawn to Enbridge Gas - EDA	114,150	41,779,000	79,215,534	29,080,690,700	1,523,869	10,520,738	524,976	12,569,583	12,044,607	524,976	12,569,583	8.79297	0.01257	0.30165
16	Dawn to Union Gas - CDA	147,828	54,105,000	34,374,445	12,320,249,600	1,973,461	4,565,323	222,410	6,761,194	6,538,784	222,410	6,761,194	3.68603	0.00411	0.12529
17	Dawn to Union Gas - EDA	1,510	553,000	830,651	304,824,700	20,158	110,320	5,503	135,981	130,478	5,503	135,981	7.20077	0.00995	0.24669
18	St. Clair to Union Gas - SWDA	204,256	74,757,000	1,589,112	364,066,600	2,726,758	211,052	6,572	2,944,382	2,937,810	6,572	2,944,382	1.19858	0.00009	0.03950
19	Dawn to Gaz Métropolitain - EDA	70,000	25,620,000	59,089,100	22,044,985,200	934,480	7,847,715	397,965	9,180,160	8,782,195	397,965	9,180,160	10.45499	0.01553	0.35926
20	Total Canadian Firm Transportation	2,835,229	1,019,744,000	4,939,661,622	1,784,965,942,500	37,849,484	656,044,120	32,222,787	726,116,391	693,893,604	32,222,787	726,116,391			
	EXPORT FIRM TRANSPORTATION														
21	Empress to Emerson	759,570	278,003,000	777,298,364	284,491,590,000	10,140,039	103,234,201	5,135,756	118,509,996	113,374,240	5,135,756	118,509,996	12.43842	0.01847	0.42740
22	Empress to Niagara Falls	695,764	254,650,000	2,116,921,204	774,794,352,000	9,288,248	281,151,588	13,986,898	304,426,734	290,439,836	13,986,898	304,426,734	34.78668	0.05493	1.19860
23	Dawn to Niagara Falls	200,000	73,200,000	60,130,000	22,007,580,000	2,669,942	7,985,959	397,290	11,053,191	10,655,901	397,290	11,053,191	4.43996	0.00543	0.15140
24	Empress to Iroquois	883,901	323,508,000	2,669,619,392	977,081,403,800	11,799,822	354,556,291	17,638,664	383,994,777	366,356,113	17,638,664	383,994,777	34.53970	0.05452	1.19007
25	Dawn to Iroquois	65,000	23,790,000	42,480,165	15,547,740,400	867,731	5,641,857	280,674	6,790,262	6,509,588	280,674	6,790,262	8.34563	0.01180	0.28618
26	Empress to Cornwall	36,154	13,232,000	112,460,630	41,159,452,900	482,645	14,936,071	743,027	16,161,743	15,418,716	743,027	16,161,743	35.53944	0.05615	1.22457
27	Empress to Philipsburg	27,843	10,191,000	91,460,917	33,476,208,200	371,696	12,147,066	604,326	13,123,088	12,518,762	604,326	13,123,088	37.46831	0.05930	1.29113
28	Steelman to Philipsburg	2,306	844,000	6,689,552	2,448,383,500	30,784	888,450	44,199	963,433	919,234	44,199	963,433	33.21892	0.05237	1.14450
29	Empress to Napierville	65,173	23,853,000	212,947,500	77,937,751,200	870,041	28,281,888	1,406,963	30,558,892	29,151,929	1,406,963	30,558,892	37.27506	0.05898	1.28446
30	Empress to Chippawa	125,841	46,058,000	383,182,697	140,245,472,000	1,679,941	50,891,088	2,531,767	55,102,796	52,571,029	2,531,767	55,102,796	34.81313	0.05497	1.19951
31	Empress to St. Clair	74,710	27,344,000	193,472,004	70,811,116,200	997,357	25,695,317	1,278,311	27,970,985	26,692,674	1,278,311	27,970,985	29.77365	0.04675	1.02561
32	Empress to East Hereford	95,223	34,852,000	330,408,449	120,930,842,000	1,271,199	43,882,058	2,183,092	47,336,349	45,153,257	2,183,092	47,336,349	39.51536	0.06264	1.36178
33	St. Clair to East Hereford	115,802	24,515,000	124,594,846	26,376,424,000	1,545,923	16,547,635	476,158	18,569,716	18,093,558	476,158	18,569,716	13.02047	0.01942	0.44749
34	St. Clair to Chippawa	319,548	79,887,000	104,447,459	26,111,864,800	4,265,873	13,871,829	471,382	18,609,084	18,137,702	471,382	18,609,084	4.73004	0.00590	0.16141
35	Kirkwall to Chippawa	41,491	14,426,000	4,745,326	1,649,901,600	553,893	630,234	29,785	1,213,912	1,184,127	29,785	1,213,912	2.37828	0.00206	0.08025
36	Total Export Firm Transportation	3,514,129	1,230,477,000	7,236,674,504	2,617,198,840,400	46,912,602	961,113,964	47,246,721	1,055,273,287	1,008,026,566	47,246,721	1,055,273,287			
37	Total System Firm Transportation	6,349,358	2,250,221,000	12,176,336,126	4,402,164,782,900	84,762,086	1,617,158,084	79,469,508	1,781,389,678	1,701,920,170	79,469,508	1,781,389,678			

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TEST OF PROPOSED TOLLS
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

		BILLING UNITS		PROPOSED TOLLS		PROPOSED REVENUE				
LINE NO.	PARTICULARS	DEMAND GJ	COMMODITY GJ	DEMAND ($/GJ/mo)	COMMODITY ($/GJ)	DEMAND ($)	COMMODITY ($)	TOTAL ($)	ALLOCATED COST ($)	EXCESS/ (DEF) ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	CANADIAN FIRM TRANSPORTATION									
1	Saskatchewan Zone	247,549	89,818,000	7.40533	0.00949	21,998,185	852,372	22,850,557	22,850,801	(244)
2	Herbert to Saskatchewan Zone	21,500	7,869,000	5.27230	0.00601	1,360,253	47,293	1,407,546	1,407,574	(28)
3	Manitoba Zone	273,652	82,991,000	11.07444	0.01605	36,366,512	1,332,005	37,698,517	37,698,302	215
4	Welwyn to Manitoba Zone	41,764	15,286,000	4.30560	0.00501	2,157,829	76,583	2,234,412	2,234,359	53
5	Western Zone	84,398	30,890,000	17.87442	0.02683	18,102,784	828,778	18,931,562	18,931,529	33
6	Northern Zone	239,219	87,554,000	27.11887	0.04233	77,848,188	3,706,161	81,554,349	81,554,047	302
7	Eastern Zone	1,156,486	423,274,000	35.15844	0.05552	487,922,924	23,500,173	511,423,097	511,424,226	(1,129)
8	Herbert to Eastern Zone	12,500	4,575,000	33.02540	0.05204	4,953,810	238,083	5,191,893	5,191,910	(17)
9	Bayhurst to Eastern Zone	2,500	915,000	34.82247	0.05497	1,044,674	50,298	1,094,972	1,094,976	(4)
10	Southwest Zone	0	0			0	0	0	0	0
11	Dawn to Enbridge Gas - CDA	217,917	79,758,000	4.47593	0.00543	11,704,575	433,086	12,137,661	12,137,367	294
12	Dawn to Enbridge Gas - EDA	114,150	41,779,000	8.79297	0.01257	12,044,610	525,162	12,569,772	12,569,583	189
13	Dawn to Union Gas - CDA	147,828	54,105,000	3.68603	0.00411	6,538,781	222,372	6,761,153	6,761,194	(41)
14	Dawn to Union Gas - EDA	1,510	553,000	7.20077	0.00995	130,478	5,502	135,980	135,981	(1)
16	St. Clair to Union Gas - SWDA	204,256	74,757,000	1.19858	0.00009	2,937,806	6,728	2,944,534	2,944,382	152
17	Dawn to Gaz Métropolitain - EDA	70,000	25,620,000	10.45499	0.01553	8,782,192	397,879	9,180,071	9,180,160	(89)
18	Total Canadian Firm Transportation	2,835,229	1,019,744,000			693,893,601	32,222,475	726,116,076	726,116,391	(315)
	EXPORT FIRM TRANSPORTATION									
19	Empress to Emerson	759,570	278,003,000	12.43842	0.01847	113,374,208	5,134,715	118,508,923	118,509,996	(1,073)
20	Empress to Niagara Falls	695,764	254,650,000	34.78668	0.05493	290,439,835	13,987,925	304,427,760	304,426,734	1,026
21	Dawn to Niagara	200,000	73,200,000	4.43996	0.00543	10,655,904	397,476	11,053,380	11,053,191	189
22	Dawn to Iroquois	65,000	23,790,000	8.34563	0.01180	6,509,591	280,722	6,790,313	6,790,262	51
23	Empress to Iroquois	883,901	323,508,000	34.53970	0.05452	366,356,104	17,637,656	383,993,760	383,994,777	(1,017)
24	Empress to Cornwall	36,154	13,232,000	35.53944	0.05615	15,418,715	742,977	16,161,692	16,161,743	(51)
25	Empress to Philipsburg	27,843	10,191,000	37.46831	0.05930	12,518,762	604,326	13,123,088	13,123,088	0
26	Steelman to Philipsburg	2,306	844,000	33.21892	0.05237	919,234	44,200	963,434	963,433	1
27	Empress to Napierville	65,173	23,853,000	37.27506	0.05898	29,151,930	1,406,850	30,558,780	30,558,892	(112)
28	Empress to Chippawa	125,841	46,058,000	34.81313	0.05497	52,571,029	2,531,808	55,102,837	55,102,796	41
29	Empress to St. Clair	74,710	27,344,000	29.77365	0.04675	26,692,673	1,278,332	27,971,005	27,970,985	20
30	Empress to East Hereford	95,223	34,852,000	39.51536	0.06264	45,153,254	2,183,129	47,336,383	47,336,349	34
31	St.Clair to East Hereford	115,802	24,515,000	13.02047	0.01942	18,093,558	476,081	18,569,639	18,569,716	(77)
32	St. Clair to Chippawa	319,548	79,887,000	4.73004	0.00590	18,137,698	471,333	18,609,031	18,609,084	(53)
33	Kirkwall to Chippawa total	41,491	14,426,000	2.37828	0.00206	1,184,127	29,718	1,213,845	1,213,912	(67)
34	Total Export Firm Transportation	3,514,129	1,230,477,000			1,008,026,522	47,245,671	1,055,272,193	1,055,273,287	(1,094)
35	Total System Firm Transportation	6,349,358	2,250,221,000			1,701,920,123	79,468,146	1,781,388,269	1,781,389,678	(1,409)

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MISCELLANEOUS REVENUE

Non-Discretionary Services

Schedule 4.1

Sales metering station (“SMS”) charges result when the total quantity of gas delivered at any delivery point is less than 3750 GJs during any contract year. Forecast sales metering station charges have been credited to the cost of service as Miscellaneous Revenue and are assigned directly to Metering. Pursuant to the 1998 Tolls Task Force Resolution 10.98 addressing volume to energy conversion, the threshold delivery volume was amended to 3750 GJs for service at all meter stations commencing on or after January 1996. SMS charges reflect the forecast flows to the applicable meter stations for 2004.

Schedule 4.2

Storage Transportation Service (“STS”) is a long-term service available to customers who are able to store gas during the winter months. The STS tolls are calculated on a point-to-point or point-to-delivery area basis. The Test Year system average unit costs are used to calculate a two-part demand and commodity toll. The STS demand and commodity energy units used to calculate the STS tolls and revenues reflect known contract renewals to January 1, 2004. The STS revenues have been credited to the cost of service as Miscellaneous Revenue.

Schedule 4.3

The incremental delivery pressure tolls for all Delivery Pressure locations, at the commencement of the 2004 Test Year, have been calculated in a manner consistent with the Board's Decisions in GH-2-87, RH-2-92 and GH-1-97. The respective delivery pressure revenues have been credited to the Cost of Service as Miscellaneous Revenue and assigned to Fixed Transmission in Toll Design Schedule 2.1.

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Schedule 4.4

Long Term Winter Firm Service ("LT-WFS") is a seasonal firm service. A forecast of the revenue is credited to the cost of service as Miscellaneous Revenue in the same Test Year during which the energy is taken. The LT-WFS tolls are calculated in a manner consistent with the Board's Decision in RH-3-94.

Discretionary Services

Schedule 4.5

Discretionary Revenue includes revenue generated by Interruptible Transportation (IT), Short Term Firm Transportation (STFT), Diversions, Enhanced Capacity Release (ECR), Parking and Loan (PALS), Interruptible Backhaul, and Storage Transportation Service (STS) Overrun services, as well as Daily Balancing charges as provided in Schedule 2.1. Total Discretionary Revenue for 2004 is estimated to be $279.7M. The Discretionary Revenue forecast has been reduced from $308.5M in TransCanada's initial filing due to new FT contracts since January 1, 2004 and toll differences resulting from changes in the Net Revenue Requirement (Schedule 2.1).

The revenue level estimated for IT and STFT is the largest component of Discretionary Revenue, and is based on the difference between TransCanada's 2004 seasonal flow forecast and firm transportation contracts held for the same period. TransCanada's flow forecast is based on an assessment of gas industry factors for the WCSB, other supply basins and North American markets.

To the extent that firm transportation contract levels and flow estimates change from year to year, discretionary revenue levels will also fluctuate. This is apparent in the approximate $28M increase in forecast discretionary revenue in 2004 compared to 2003 actual. While forecast throughput over the same period is expected to decline by about 320 TJ/d, long-haul FT contract levels to eastern markets have decreased by approximately 740 TJ/d.

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Schedule 4.5, page 1 provides a summary of the flow and contract information used to determine IT and STFT throughput. The table is divided into four parts, described below.

Part A provides TransCanada's estimate of the WCSB flows moving on the Mainline under discretionary services. TransCanada deducts from the total flow forecast the amounts of contracted firm transportation, as well as estimated fuel requirements. The remainder is anticipated to move under IT and STFT services.

Parts B and C determine the split between expected WCSB discretionary flow delivery by TransCanada to western markets up to and including Emerson, and eastern markets via long-haul service on the integrated system. Forecast use of TransCanada's GLGT TBO contracts, overall use of the GLGT and Viking systems, and fuel requirements on GLGT are key elements of this calculation.

Part B determines the expected discretionary flow to eastern markets. This is calculated by deducting the contracted long-haul FT to be delivered east of Emerson from the Western supply anticipated to flow east of Emerson from the Western supply anticipated to flow east of Emerson.

Part C derives the expected discretionary flow to Emerson, based on the difference between total Western receipt discretionary flow, and that expected to flow to markets east of Emerson via both southern and northern routes.

Part D provides TransCanada's estimate of discretionary flow in the eastern market area. The calculation is based on eastern market demand in 2003, adjusted for 2004 contracted long-haul and short-haul firm transportation, and the discretionary long-haul flows calculated in Part B.

Schedule 4.5, page 2 provides a summary of the forecast revenues generated by the estimated IT and STFT throughput. The first section of the table summarizes the seasonal discretionary flow information. The second section provides the tolls TransCanada has assumed for these flows. The tolls are based on a blend of 25%

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IT and 75% STFT base tolls for the relevant hauls. These percentages are based on the historical and expected usage of IT and STFT. For the eastern short-hauls, TransCanada has assumed the flows will move a relatively short distance (for example, from St. Clair to Union SWDA), since the capacity to the EDA and eastern exports on that part of the system is fully contracted. The last section of the table aggregates total revenues expected from IT and STFT flows with TransCanada's estimate of revenues from other discretionary services.

Schedule 4.6

Enhanced Capacity Release ("ECR") is a service enhancing long-haul firm transportation. The ECR Surcharge reflects the system average unit cost for Metering generated on Line 1 of Toll Design Schedule 3.1.

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STORAGE TRANSPORTATION SERVICE REVENUE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS					($)
	(a)					(b)
	Centra Gas (Manitoba) Ltd. - MDA					
1	Demand:	($ 2.78917 /GJ/mo. x	54,418 GJ	x	12 months)	1,821,373
2	Commodity:	($ 0.00273 /GJ x	10,413,000 GJ)			28,427
3						1,849,800
	Union Gas - WDA					
4	Demand:	($ 17.98333 /GJ/mo. x	3,150 GJ	x	12 months)	679,770
5	Commodity:	($ 0.02752 /GJ x	674,000 GJ)			18,548
6						698,318
	Union Gas - NDA					
7	Demand:	($ 7.25167 /GJ/mo. x	49,100 GJ	x	12 months)	4,272,684
8	Commodity:	($ 0.01001 /GJ x	11,777,000 GJ)			117,888
9						4,390,572
	Union Gas - EDA					
10	Demand:	($ 4.63500 /GJ/mo. x	68,520 GJ	x	12 months)	3,811,082
11	Commodity:	($ 0.00575 /GJ x	7,591,000 GJ)			43,648
12						3,854,730
	Kingston PUC					
13	Demand:	($ 4.47500 /GJ/mo. x	13,167 GJ	x	12 months)	707,068
14	Commodity:	($ 0.00548 /GJ x	726,000 GJ)			3,978
15						711,046
	Gaz Metropolitain - EDA					
16	Demand:	($ 8.12500 /GJ/mo. x	196,174 GJ	x	12 months)	19,126,965
17	Commodity:	($ 0.01144 /GJ x	18,143,000 GJ)			207,556
18						19,334,521
	Enbridge - CDA					
19	Demand:	($ 1.13667 /GJ/mo. x	283,892 GJ	x	12 months)	3,872,298
20	Commodity:	($ 0.00004 /GJ x	27,412,000 GJ)			1,096
21						3,873,394
	Enbridge - EDA					
22	Demand:	($ 2.98583 /GJ/mo. x	80,611 GJ	x	12 months)	2,888,289
23	Commodity:	($ 0.00306 /GJ x	4,095,000 GJ)			12,531
24						2,900,820
	Cornwall					
25	Demand:	($ 6.27000 /GJ/mo. x	10,785 GJ	x	12 months)	811,463
26	Commodity:	($ 0.00841 /GJ x	721,000 GJ)			6,064
27						817,527
	Philipsburg					
28	Demand:	($ 8.19833 /GJ/mo. x	20,779 GJ	x	12 months)	2,044,237
29	Commodity:	($ 0.01156 /GJ x	1,593,000 GJ)			18,415
30						2,062,652
31	Total Storage Transportation Service Revenue					40,493,380

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FUNCTIONALIZATION OF STORAGE TRANSPORTATION SERVICE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	DISTANCES (km)	ENERGY GJ	REVENUE ($)
	(a)	(b)	(c)	(d)
	STORAGE TRANSPORTATION REVENUE			
	STS Revenue - Fixed Energy (FV)			
1	Centra Gas Manitoba - MDA		54,418	726,465
2	Union Gas - WDA		3,150	42,052
3	Union Gas - NDA		49,100	655,471
4	Union Gas - EDA		68,520	914,722
5	Kingston PUC		13,167	175,776
6	Gaz Metropolitain - EDA		196,174	2,618,866
7	Enbridge - CDA		283,892	3,789,876
8	Enbridge - EDA		80,611	1,076,133
9	Cornwall		10,785	143,977
10	Philipsburg		20,779	277,394
11	STS Demand Volume		780,596	10,420,732
12	STS Revenue - Fixed Energy (FV)			10,420,732
	STS Revenue - Fixed Transmission (FVD)			
13	Centra Gas Manitoba - MDA	151.48	54,418	1,094,908
14	Union Gas - WDA	1524.33	3,150	637,718
15	Union Gas - NDA	554.68	49,100	3,617,213
16	Union Gas - EDA	318.30	68,520	2,896,360
17	Kingston PUC	303.81	13,167	531,292
18	Gaz Metropolitain - EDA	633.58	196,174	16,508,099
19	Enbridge - CDA	2.22	283,892	82,422
20	Enbridge - EDA	169.23	80,611	1,812,156
21	Cornwall	465.98	10,785	667,486
22	Philipsburg	640.26	20,779	1,766,843
23	STS Demand Volume		780,596	29,614,497
24	STS Revenue - Fixed Transmission (FVD)			29,614,497
	STS Revenue - Variable Transmission (VVD)			
25	Centra Gas Manitoba - MDA	151.48	10,413,000	28,427
26	Union Gas - WDA	1524.33	674,000	18,548
27	Union Gas - NDA	554.68	11,777,000	117,888
28	Union Gas - EDA	318.30	7,591,000	43,648
29	Kingston PUC	303.81	726,000	3,978
30	Gaz Metropolitain - EDA	633.58	18,143,000	207,556
31	Enbridge - CDA	2.22	27,412,000	1,096
32	Enbridge - EDA	169.23	4,095,000	12,531
33	Cornwall	465.98	721,000	6,064
34	Philipsburg	640.26	1,593,000	18,415
35	STS Commodity Volume		83,145,000	458,151
36	STS Revenue - Variable Transmission (VVD)			458,151
37	Total STS Revenue			40,493,380

Note: Revenue from Fixed Energy, Fixed Transmission and Variable Transmission is based on System Average Unit Costs from Schedule 3.1

SALE OF DELIVERY PRESSURE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS (a)							ENERGY (GJ) (b)	AMOUNT ($) (c)	
	EMERSON 1 & 2									
	Pressure to 750 psi (5170 kPa)									
1	Incremental Owning and Operating Fixed Cost - Gross								$4,266,369	
2	- Misc. Revenue Credit								($966,279)	
3	- Net								$3,300,090	
	Fixed Allocation Units (GJ/d)									
4	TOTAL EMERSON 1 & 2							2,180,363	$3,300,090	
5	Pressure Charge	=	3,300,090	/	2,180,363	/	12 =		$0.12613	/GJ/mo
6	Incremental Fuel Ratio	=	0.18 %							
	EMERSON 2									
	Pressure from 750 to 793 psi (5170 to 5465 kPa)									
7	Incremental Owning and Operating Fixed Cost - Gross								$1,070,734	
8	- Misc. Revenue Credit								($325,368)	
9	- Net								$745,366	
	Fixed Allocation Units (GJ/d)									
10	TOTAL EMERSON 2							2,028,099	$745,366	
11	Pressure Charge	=	745,366	/	2,028,099	/	12 =		$0.03063	/GJ/mo
12	Incremental Fuel Ratio	=	0.18 %							
	SWDA									
	Pressure to 700 psi (4830 kPa)									
13	Incremental Owning and Operating Fixed Cost - Gross								$2,874,730	
14	- Misc. Revenue Credit								($590,099)	
15	- Net								$2,284,631	
	Fixed Allocation Units (GJ/d)									
16	TOTAL SWDA							1,887,086	$2,284,631	
17	Pressure Charge	=	2,284,631	/	1,887,086	/	12 =		$0.10089	/GJ/mo
18	Incremental Fuel Ratio	=	0.00 %							

* For Enbridge & Union, average day of the Annual Contract entitlement is the basis of the rate determination & payment

SALE OF DELIVERY PRESSURE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS (a)						ENERGY (GJ) (b)	AMOUNT ($) (c)	
	NIAGARA FALLS								
	Pressure to 700 psi (4830 kPa)								
1	Incremental Owning and Operating Fixed Cost - Gross							$1,227,011	
2			- Misc. Revenue Credit					($64,157)	
			- Net					$1,162,854	
	Fixed Allocation Units (GJ/d)								
3	TOTAL NIAGARA FALLS						895,764	$1,162,854	
4			1,162,854	/	895,764	/ 12 =		$0.10818	/GJ/mo
5	Incremental Fuel Ratio	=	0.00 %						
	IROQUOIS								
	Pressure to 1440 psi (9930 kPa)								
6	Incremental Owning and Operating Fixed Cost - Gross							$10,178,563	
7			- Misc. Revenue Credit					($548,333)	
8			- Net					$9,630,230	
	Fixed Allocation Units (GJ/d)								
9	TOTAL IROQUOIS						971,743	$9,630,230	
10	Pressure Charge	=	9,630,230	/	971,743	/ 12 =		$0.82586	/GJ/mo
11	Incremental Fuel Ratio	=	0.53 %						

SALE OF DELIVERY PRESSURE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS							ENERGY (GJ)	AMOUNT ($)	
	(a)							(b)	(c)	
	CHIPPAWA									
	Pressure to 1225 psi (8445 kPa)									
1	Incremental Owning and Operating Fixed Cost - Gross								$7,019,650	
2				- Misc. Revenue Credit					($217,923)	
3				- Net					$6,801,727	
	Fixed Allocation Units (GJ/d)									
4	TOTAL CHIPPAWA							504,318	$6,801,727	
5	Pressure Charge	=	6,801,727	/	504,318	/	12	=	$1.12392	/GJ/mo
6	Incremental Fuel Ratio	=	0.70 %							
	EAST HEREFORD									
	Pressure to 775 psig (5345 kPa)									
7	Incremental Owning and Operating Fixed Cost - Gross								$4,077,471	
8				- Misc. Revenue Credit					($10,386)	
9				- Net					$4,067,085	
	Fixed Allocation Units (GJ/d)									
10	TOTAL FIXED EAST HEREFORD							211,025	$4,067,085	
11	Pressure Charge	=	4,067,085	/	211,025	/	12	=	$1.60608	/GJ/mo
12	Incremental Owning and Operating Variable Cost - Gross								$636,627	
13				- Misc. Revenue Credit					$0	
14				- Net					$636,627	
	Variable Allocation Units (TJ)									
15	TOTAL VARIABLE EAST HEREFORD							59,367,000	$636,627	
16	Pressure Charge	=	636,627	/	59,367,000				$0.01072	/GJ
17	Incremental Fuel Ratio	=	0.00 %							
18	Total Sale of Delivery Pressure (Fixed)								$27,991,983	
19	Total Sale of Delivery Pressure (Variable)								$636,627	
20	Total Sale of Delivery Pressure								$28,628,610	

Note: Sale of Delivery Pressure is Functionalized as Fixed Transmission except the Variable Units for East Hereford.
Delivery pressure on Transmission by Others:

Allocated costs on Great Lakes (T4) from Emerson 1 and 2;	$2,672,682
Allocated costs on Union M-12 from Dawn	$1,852,947

LONG TERM WINTER FIRM SERVICE REVENUE
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	LONG TERM WINTER FIRM SERVICE TOLL ($/GJ)	ENERGY (GJ)	REVENUE ($)
	(a)	(b)	(c)	(d)
1	Empress to Iroquois - LT-WFS	1.66610	801,800	1,335,879
2	Total		801,800	1,335,879

Note: The Iroquois FT Demand and Commodity Rates are from Schedule 5.1
LT-WFS Toll is 1.4 x the Iroquois Toll based on the accepted bid maximum as per NEB Decision RH-3-94.

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Discretionary Throughput Forecast

			Jan - Mar 2004 GJ/Day	Summer 2004 GJ/Day	Nov - Dec 2004 GJ/Day
Part A	Discretionary Western Receipt Flow				
	Net Western Supply Available		6,313,561	5,567,004	5,709,015
	Less:	Western Receipt FT Contracts	4,825,480	4,825,480	4,825,480
	Discretionary Western Receipt Flow		**1,488,081**	**741,524**	**883,535**
Part B	Discretionary Western Receipts Flowing East of Emerson				
	GLGT Average Operating Capacity		2,498,805	2,320,168	2,498,805
	Less:	Expected GLGT TBO use	1,082,231	1,367,100	1,082,231
		GLGT expected fuel requirements	94,955	109,048	94,955
	GLGT Expected Flow (net of Mainline TBO)		1,321,620	844,020	1,321,620
	Net Western Supply Available		6,313,561	5,567,004	5,709,015
	Less:	Expected Deliveries between Empress and Emerson (1)	1,034,825	794,038	1,034,825
		GLGT Expected Flow (2)	1,321,620	844,020	1,321,620
	Western Supply Flowing past Emerson		**3,957,117**	**3,928,945**	**3,352,570**
	VS				
	Western Receipt FT Contracts		4,825,480	4,825,480	4,825,480
	Less:	Contracted FT between Empress and Emerson	1,317,659	1,317,659	1,317,659
	Net Western Receipt FT moving east of Emerson		**3,507,821**	**3,507,821**	**3,507,821**
	Discretionary Western Receipts Flowing East of Emerson		**449,296**	**421,124**	**-**
Part C	Discretionary Western Receipts Flowing to Emerson				
	Discretionary Western Receipt Flow		1,488,081	741,524	883,535
	Less:	Discretionary Western Receipts Flowing East of Emerson	449,296	421,124	-
	Discretionary Western Receipts Flowing to Emerson		**1,038,786**	**320,399**	**883,535**
Part D	Eastern Short-Haul Discretionary Flow				
	Total Eastern Demand (2003)		7,035,442	4,530,030	6,150,138
	Less:	Net Western Receipt FT moving east of Emerson	3,507,821	3,507,821	3,507,821
		Discretionary Western Receipts Flowing East of Emerson	449,296	421,124	-
		Eastern Short-Haul FT	2,171,430	2,171,430	2,171,430
	Discretionary Eastern Short-Haul		**906,895**	**-**	**470,887**

Notes

(1) Includes Saskatchewan Zone, Manitoba Zone, Emerson 1 (Viking) and GLGT fuel deliveries
(2) GLGT Average Operating Capacity less TransCanada's expected use of GLGT TBO and GLGT fuel requirements

Discretionary Revenue Calculation

	Jan - Mar 2004	Summer 2004	Nov - Dec 2004	
Discretionary Flow (TJ/d)				
Empress/SK receipts to Emerson	1,039	320	884	
Empress/SK receipts to eastern markets	449	421	0	
Eastern short-haul	907	0	471	
Toll Assumptions ($/GJ)				
Empress/SK receipts to Emerson (1)	0.438	0.438	0.438	
Empress/SK receipts to eastern markets	1.242	1.242	1.242	
Eastern short-haul	0.040	0.040	0.040	
Discretionary Revenue ($M) - from STFT & IT service				**Annual Total ($)**
Empress/SK receipts to Emerson	41.4	30.0	23.6	95.1
Empress/SK receipts to eastern markets	50.8	111.9	0.0	162.7
Eastern short-haul	3.3	0.0	1.2	4.5
Discretionary Revenue from STFT & IT Service	95.5	141.9	24.8	262.2
Other				17.5
Total Discretionary Revenue ($M)				**$279.7**

Notes

		$/GJ/Day				$/GJ/Day
(1) Toll Assumption:	Empress to Emerson FT Toll:	0.4274				
	Empress to Emerson IT Bid Floor:	0.4701	at expected use:	25%	weighted toll:	0.118
	Empress to Emerson STFT Bid Floor:	0.4274	at expected use:	75%	weighted toll:	0.321
						0.438

ENHANCED CAPACITY RELEASE (ECR) SURCHARGE *
FOR THE TEST YEAR ENDING DECEMBER 31, 2004

LINE NO.	PARTICULARS	System Average Unit Cost of Metering ($/GJ/Year)	($/GJ)
	(a)	(b)	(c)
1	ECR Surcharge	13.3497100022	0.03657

*NOTE: The ECR Surcharge is based on the Tolls Task Force Resolution 97-17 and approved by the National Energy Board, by letter dated September 5, 1996.

PROPOSED TOLLS

Schedule 5.1

This schedule sets out the 2004 proposed tolls for the following:

- Firm Transportation Service,
- Storage Transportation Service,
- Long Term Winter Firm Service,
- Short Term Firm Transportation,
- East/West Differential for STFT,
- East/West Differential for IT,
- Backhaul Transportation,
- Enhanced Capacity Release
- Delivery Pressure,
- System Average Unit Costs,
- Distances for IT Services.

Schedule 5.2

- Interruptible Transportation Bid Floor Tolls

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CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS	DEMAND TOLL ($/GJ/mo)	COMMODITY TOLL ($/GJ)	100% LF TOLL (¢/GJ)
	(a)	(b)	(c)	(d)
	CANADIAN FIRM TRANSPORTATION			
1	Saskatchewan Zone	7.40533	0.00949	25.295
2	Herbert to Saskatchewan Zone	5.27230	0.00601	17.935
3	Manitoba Zone	11.07444	0.01605	38.014
4	Welwyn to Manitoba Zone	4.30560	0.00501	14.656
5	Western Zone	17.87442	0.02683	61.448
6	Northern Zone	27.11887	0.04233	93.391
7	Eastern Zone	35.15844	0.05552	121.141
8	Bayhurst to Eastern Zone	34.82247	0.05497	119.982
9	Herbert to Eastern Zone	33.02540	0.05204	113.781
10	Southwest Zone	29.86773	0.04700	102.895
	EXPORT FIRM TRANSPORTATION			
11	Empress to Emerson	12.43842	0.01847	42.740
12	Empress to St. Clair	29.77365	0.04675	102.561
13	Empress to Chippawa	34.81313	0.05497	119.951
14	Empress to Niagara Falls	34.78668	0.05493	119.860
15	Empress to Iroquois	34.53970	0.05452	119.007
16	Empress to Cornwall	35.53944	0.05615	122.457
17	Empress to Napierville	37.27506	0.05898	128.446
18	Empress to Philipsburg	37.46831	0.05930	129.113
19	Steelman to Philipsburg	33.21892	0.05237	114.450
20	Empress to East Hereford	39.51536	0.06264	136.178
	MISC POINT-TO-POINT FIRM TRANSPORTATION			
21	Dawn to Enbridge CDA	4.47593	0.00543	15.258
22	Dawn to Enbridge EDA	8.79297	0.01257	30.165
23	Dawn to Union CDA	3.68603	0.00411	12.529
24	Dawn to Union EDA	7.20077	0.00995	24.669
25	Dawn to GMi - EDA	10.45499	0.01553	35.926
26	Dawn to Niagara Falls	4.43996	0.00543	15.140
27	Dawn to Iroquois	8.34563	0.01180	28.618
28	St. Clair to Union SWDA	1.19858	0.00009	3.950
29	St. Clair to Chippawa	4.73004	0.00590	16.141
30	Kirkwall to Chippawa	2.37828	0.00206	8.025
31	St. Clair to East Hereford	13.02047	0.01942	44.749

* All tolls are expressed and payable in Canadian Dollars.

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PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS (a)	DEMAND TOLL ($/GJ/mo) (b)	COMMODITY TOLL ($/GJ) (c)
	STORAGE TRANSPORTATION SERVICE		
1	Centra Gas (Manitoba) - MDA	2.78917	0.00273
2	Union Gas - WDA	17.98333	0.02752
3	Union Gas - NDA	7.25167	0.01001
4	Union Gas - EDA	4.63500	0.00575
5	Kingston	4.47500	0.00548
6	Gaz Métropolitain - EDA	8.12500	0.01144
7	Enbridge Gas - CDA	1.13667	0.00004
8	Enbridge Gas - EDA	2.98583	0.00306
9	Cornwall	6.27000	0.00841
10	Philipsburg	8.19833	0.01156
	LONG TERM WINTER FIRM SERVICE		
11	Empress to Iroquois		1.66610

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PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS (a)	MINIMUM (1) ($/GJ) (b)
	SHORT TERM FIRM TRANSPORTATION	
1	Empress to Saskatchewan Zone	0.25295
2	Herbert to Saskatchewan Zone	0.17935
3	Empress to Manitoba Zone	0.38014
4	Welwyn to Manitoba Zone	0.14656
5	Empress to Western Zone	0.61448
6	Empress to Northern Zone	0.93391
7	Bayhurst to Eastern Zone	1.19982
8	Herbert to Eastern Zone	1.13781
9	Empress to Eastern Zone	1.21141
10	Empress to Southwest Zone	1.02895
11	Empress to Emerson	0.42740
12	Empress to St. Clair	1.02561
13	Empress to Chippawa	1.19951
14	Empress to Niagara Falls	1.19860
15	Empress to Iroquois	1.19007
16	Empress to Cornwall	1.22457
17	Empress to Napierville	1.28446
18	Empress to Philipsburg	1.29113
19	Steelman to Philipsburg	1.14450
20	Empress to East Hereford	1.36178
21	Dawn to Enbridge CDA	0.15258
22	Dawn to Enbridge EDA	0.30165
23	Dawn to Union CDA	0.12529
24	Dawn to Union EDA	0.24669
25	Dawn to GMi - EDA	0.35926
26	Dawn to Niagara Falls	0.15140
27	Dawn to Iroquois	0.28618
28	St. Clair to Union SWDA	0.03950
29	St. Clair to Chippawa	0.16141
30	Kirkwall to Chippawa	0.08025
31	St. Clair to East Hereford	0.44749

(1) The Minimum STFT Toll is the 100% Load Factor FT toll for the applicable path.

PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

CALCULATION OF SHORT TERM FIRM TRANSPORTATION EAST/WEST DIFFERENTIAL

LINE NO.	PARTICULARS			NORTHERN ROUTE EASTERN ZONE	MANITOBA ZONE	DIFFERENCE
	(a)			(b)	(c)	(d)
1	% Flow (1)			100%		
	COSTS					
2	Marginal Fuel (2)	East - via North		12.00%		
3		West			2.80%	
4	Average Fuel Ratio (3)			-4.79%	-1.34%	
5	Incremental Fuel			7.21%	1.46%	
6	Cost of Gas (4)		($/GJ)	0.4689	0.0949	0.3739
7	Commodity		($/GJ)	0.0555	0.0161	0.0395
8	Total Cost		($/GJ)	0.5244	0.1110	**0.4134**

(1) This represents the % of the volume that goes through the northern route to the Eastern Zone based on the assumption that STFT flows through the north only.

(2) Marginal fuel is the fuel required to transport one additional unit of gas.

(3) The fuel ratio is the average amount of fuel supplied by a shipper for transportation of one unit of gas. The average fuel ratios have been updated to reflect the average from December, 2002 to November, 2003.

(4) The cost of gas ($6.503/GJ) is the average monthly Alberta Spot Price at Empress for the months of November 2002 to October 2003 as reported in the Canadian Gas Price Reporter, October 2003.

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PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

CALCULATION OF INTERRUPTIBLE TRANSPORTATION EAST/WEST DIFFERENTIAL

LINE NO.	PARTICULARS		SOUTHERN ROUTE (9) GLGT & Union Overrun EASTERN ZONE	MANITOBA ZONE	DIFFERENCE
	(a)		(b)	(c)	(d)
	COSTS				
1	Marginal Fuel (1)	West	2.80%	2.80%	
2		GLGT (2)	4.30%		
3		Union (3)	0.74%		
4	Average Fuel Ratio (4)		(4.79%)	(1.34%)	
5	Incremental Fuel		3.05%	1.46%	
6	Cost of Gas (5)	($/GJ)	0.1983	0.0949	0.1034
	Great Lakes Overrun Costs:				
7	Eastern Zone (6)		0.3314	n/a	
8	Refund to Shipper (7)		0.2088	n/a	
9	Net GLGT Overrun	($/GJ)	0.1226	0.0000	0.1226
10	Union Overrun (8)	($/GJ)	0.0840	0.000	0.0840
11	Commodity	($/GJ)	0.05552	0.01605	0.0395
12	Total Cost	($/GJ)	0.4605	0.1110	**0.3495**
13	Eastern Zone:	100% LF Toll	121.1410	($/GJ)	
14		110% of 100% LF Toll	133.2551	($/GJ)	

(1) Marginal fuel is the fuel required to transport one additional unit of gas.
(2) This is the Average GLGT Fuel Rate posted from December 2002 to November 2003.
(3) This is the Average Union Fuel Rate from December 2002 to November 2003.
(4) The fuel ratio is the average amount of fuel supplied by a shipper for transportation of one unit of gas (Average from December 2002 to November 2003).
(5) The cost of gas ($6.503/GJ) is the average monthly Alberta Spot Price at Empress for the months of November 2002 to October 2003 as reported in the Canadian Gas Price Reporter, October 2003.
(6) The Great Lakes overrun rate is based on the overrun rate of US $0.25216/Dth (140% Load Factor) plus ACA of $0.00210/Dth converted at an exchange rate of 0.7273 for the Canadian dollar based on the 2004 Tolls Application.
(7) The refund represents 90% of the revenue returned to TransCanada for shipping a 70% share of the volumes on the GLGT system.
(8) The Union overrun rate is charged to TransCanada for transportation from Dawn to Parkway as of January 1, 2003.
(9) This represents the calculation through the southern route to the Eastern Zone based on the assumption that IT flows through the south only.

PROPOSED CANADIAN AND EXPORT TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	PARTICULARS (a)	COMMODITY TOLL ($/GJ) (b)
	BACKHAUL SERVICE	
	Chippawa to Union SWDA	
1	Winter IT	0.15374
2	Summer IT	0.07687
	Emerson to Centra MDA	
3	Winter IT	0.09169
4	Summer IT	0.04585
	Dawn to St. Clair	
5	Winter IT	0.04525
6	Summer IT	0.02262
	Emerson to Empress	
7	Winter IT	0.40893
8	Summer IT	0.20447
	MULTIPLE HANDSHAKES (MHPS) *(1)	
9	Winter Minimum	0.00000
10	Winter Maximum	0.00000
11	Summer Minimum	0.00000
12	Summer Maximum	0.00000
	ENHANCED CAPACITY RELEASE	
13	ECR Surcharge	0.03657

	DELIVERY PRESSURE (a)	DEMAND TOLL ($/GJ/mo) (b)	COMMODITY TOLL ($/GJ) (c)	DAILY EQUIVALENT *(2) ($/GJ) (d)
14	Emerson - 1 (Viking)	0.12613	0.00000	0.00415
15	Emerson - 2 (Great Lakes)	0.15676	0.00000	0.00515
16	Dawn	0.10089	0.00000	0.00332
17	Niagara Falls	0.10818	0.00000	0.00356
18	Iroquois	0.82586	0.00000	0.02715
19	Chippawa	1.12392	0.00000	0.03695
20	East Hereford	1.60608	0.01072	0.06352

*(1) As per TTF Resolution 07.2003, Mulitple Handshakes and Pooling Service has been terminated.
The resolution incorporates "no cost" title transfer as a feature of transportation services.

*(2) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, and STFT.

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SYSTEM AVERAGE UNIT COST OF TRANSPORTATION
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	ALLOCATION METHOD	FUNCTIONALIZED ($)	APPLICABLE ALLOCATION UNITS (GJ)	UNIT COSTS	
	(a)	(b)	(c)	(d)	
1	Fixed Energy	84,762,088	6,349,358	13.3497100022	$/GJ
2	Fixed Energy-Distance	1,617,158,082	12,176,336,126	0.1328115506	$/GJ/km
3	Variable Energy-Distance	79,469,508	4,402,164,782,900	0.0000180524	$/GJ/km

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PROPOSED INTERRUPTIBLE SERVICE DISTANCES
FOR TOLLS EFFECTIVE JANUARY 1, 2004

LONG HAUL DISTANCES — DELIVERY POINT

RECEIPT POINT	Sask. Zone	Manitoba Zone	Western Zone	Northern Zone	Eastern Zone	Southwest Zone	Spruce	Emerson	St. Clair	Niagara Falls	Chippawa	Iroquois	Cornwall	Napierville	Philipsburg	East Hereford
Suffield	523.81	886.90	1484.14	2342.62	3073.63	2601.38	1000.21	1021.31	2587.61	3040.56	3042.95	3018.24	3108.66	3265.39	3282.85	3467.57
Richmound	523.62	886.71	1483.95	2342.43	3073.44	2601.19	1000.02	1021.12	2587.42	3040.37	3042.76	3018.05	3108.47	3265.20	3282.66	3467.38
Bayhurst	495.49	858.58	1455.82	2314.30	3045.31	2573.06	971.89	992.99	2559.29	3012.24	3014.63	2989.92	3080.34	3237.07	3254.53	3439.25
Liebenthal	482.24	845.33	1442.57	2301.05	3032.06	2559.81	958.64	979.74	2546.04	2998.99	3001.38	2976.67	3067.09	3223.82	3241.28	3426.00
Success	390.34	753.43	1350.67	2209.15	2940.16	2467.91	866.74	887.84	2454.14	2907.09	2909.48	2884.77	2975.19	3131.92	3149.38	3334.10
Herbert	333.12	696.21	1293.45	2151.93	2882.94	2410.69	809.52	830.62	2396.92	2849.87	2852.26	2827.55	2917.97	3074.70	3092.16	3276.88
Steelman	141.89	504.98	1102.22	1960.70	2691.71	2219.46	618.29	639.39	2205.69	2658.64	2661.03	2636.32	2726.74	2883.47	2900.93	3085.65
Welwyn	BH	277.34	874.58	1733.06	2464.07	1991.82	390.65	411.75	1978.05	2431.00	2433.39	2408.68	2499.10	2655.83	2673.29	2858.01
Shackleton	433.22	796.31	1393.55	2252.03	2983.04	2510.79	909.62	930.72	2497.02	2949.97	2952.36	2927.65	3018.07	3174.8	3192.26	3376.98

DOMESTIC SHORT HAULS — DELIVERY POINT

RECEIPT POINT	Union WDA	TCPL WDA	Union NDA	TCPL NDA	TPLP NDA	Gmi NDA	Union SSMDA	Enbridge SWDA	Union SWDA	Union NCDA	Union CDA	Enbridge CDA	Union EDA	Enbridge EDA	Gmi EDA	KPUC EDA
Sault Ste. Marie	1777.68	1930.12	1378.77	1518.49	1778.89	1310.37	10.81	597.63	578.67	996.37	825.34	898.22	1133.71	1293.80	1458.09	1128.32
St. Clair	1739.02	1535.84	805.40	944.69	1205.09	736.57	584.67	23.83	4.87	433.96	251.54	324.42	575.05	722.35	884.29	554.52
Dawn	1718.57	1512.01	781.57	920.86	1181.26	712.74	608.50		BH	410.13	227.71	300.59	551.22	696.06	860.46	530.69
Parkway	1503.64	1285.13	554.69	693.98	954.38	485.86	835.39	226.88	245.84	183.25	7.06	73.71	324.34	469.30	633.60	303.81
Kirkwall	1541.93	1323.34	592.90	732.19	992.59	524.07	797.17	BH	BH	221.46	39.04	111.92	362.55	507.51	671.79	342.02
Niagara Falls	1636.36	1417.84	687.40	826.69	1087.09	618.57	909.15	BH	BH	315.96	127.08	167.73	457.05	602.01	766.29	436.53
Chippawa	1638.75	1420.23	689.79	829.08	1089.48	620.96	911.54	BH	BH	318.35	129.47	170.82	459.44	604.40	735.92	438.92
Iroquois	BH	BH	BH	BH	BH	557.09	1262.05	653.54	672.50	508.87	433.72	401.63	112.17	93.83	215.87	122.85
East Hereford	BH	BH	BH	BH	BH	946.69	1660.61	1052.11	1071.06	905.49	832.29	800.20	502.20	473.50	312.27	521.41
Emerson	612.57	795.52	1525.94	1386.67	1126.26	1625.43	1145.41	1590.03	1571.07	1897.26	1817.74	1890.54	2114.78	2126.37	2349.83	2120.72
Cornwall	BH	BH	BH	BH	BH	587.45	1301.37	692.86	711.82	546.38	469.25	440.95	143.30	116.61	168.17	162.17
Union NDA		948.30								346.67	561.74	553.13	693.96	608.04	824.37	
Enbridge CDA		1501.43	553.13							216.46	75.42		299.95	443.70	608.55	
Enbridge EDA		1556.34	608.04							519.04	476.19	443.70	178.43		281.86	
GMIT EDA		1772.68	824.37							731.02	640.43	608.55	310.56	281.86		
Union CDA		1510.70	561.74							215.73		75.42	329.31	476.19	640.43	
Union EDA		1642.26	693.96							411.74	329.31	299.95		178.43	310.56	
Union WDA			948.30							1294.97	1510.70	1501.43	1642.26	1556.34	1772.68	
Union NCDA											215.73					
Union SSMDA											836.15					
CentraT MDA											1959.68					

EXPORT SHORT HAULS — DELIVERY POINT

RECEIPT POINT	Niagara Falls	Chippawa	Iroquois	Cornwall	Napierville	Phillipsburg	East Hereford	Spruce	Emerson	St. Clair
Sault Ste. Marie	898.27	900.66	1251.17	1290.49	1447.28	1464.77	1649.73	1276.51	BH	584.67
St. Clair	324.47	326.86	677.37	716.69	873.51	890.97	1075.93	1708.11	1566.20	
Dawn	300.65	303.04	653.54	692.86	849.68	867.14	1052.11	1731.94	BH	23.83
Parkway	132.71	135.10	426.66	465.98	622.80	640.26	825.23	1958.82	1816.91	250.71
Kirkwall	111.98	114.37	464.87	504.19	661.01	678.47	863.44	1920.61	BH	212.50
Niagara Falls		38.67	559.37	598.69	755.52	772.97	957.93	2032.59	BH	324.47
Chippawa	38.67		561.76	601.08	757.91	775.36	960.32	2034.98	BH	326.86
Iroquois	559.37	561.76		48.27	205.09	222.55	407.51	BH	2151.88	677.37
East Hereford	957.93	960.32	407.51	BH	388.85	406.31		BH	2541.47	1075.93
Emerson	1890.77	1893.06	2151.88	2182.23	2339.05	2356.51	2541.47	141.91		1566.20
Cornwall	616.17	618.56	48.27		156.82	174.28	359.24	BH	2182.23	716.69
Enbridge CDA	167.73		403.89		595.40	612.79	800.20			
Enbridge EDA	602.01		93.83		271.11	288.57	473.50			
GMIT EDA	766.29		215.87		168.15	181.43	312.27			
Union CDA	127.08		433.72		629.86	647.32	832.29			
Union EDA	457.05		112.17		299.78	317.24	502.20			
Union WDA	1636.36		1539.59		1726.77	1744.22	1929.18			
Union NDA	687.40		625.91		813.09	830.54	1015.50			

Note: The variable allocation unit load centre is displayed on this table. However, if there is a FT contract in the test year, the tolls will be based on both the variable and fixed load centres

PROPOSED INTERRUPTIBLE TRANSPORTATION SERVICE TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	RECEIPT POINT		DELIVERY POINT	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	(100% LF Toll) ($/GJ)	(1) IT Bid Floor (110% of FT Toll) ($/GJ)
	Long Haul Domestic Zones						
1	Empress	To	Sask. Zone	7.40533	0.00949	0.2530	0.2782
2	Empress	To	Manitoba Zone	11.07444	0.01605	0.3801	0.4182
3	Empress	To	Western Zone	17.87442	0.02683	0.6145	0.6759
4	Empress	To	Northern Zone	27.11887	0.04233	0.9339	1.0273
5	Empress	To	Eastern Zone	35.15844	0.05552	1.2114	1.3326
6	Empress	To	Southwest Zone	29.86773	0.04700	1.0290	1.1318
7	Suffield	To	Sask. Zone	6.90981	0.00946	0.2366	0.2603
8	Suffield	To	Manitoba Zone	10.92836	0.01601	0.3753	0.4128
9	Suffield	To	Western Zone	17.53839	0.02679	0.6034	0.6637
10	Suffield	To	Northern Zone	27.03973	0.04229	0.9313	1.0244
11	Suffield	To	Eastern Zone	35.13027	0.05549	1.2105	1.3316
12	Suffield	To	Southwest Zone	29.90359	0.04696	1.0301	1.1331
13	Richmound	To	Sask. Zone	6.90771	0.00945	0.2366	0.2603
14	Richmound	To	Manitoba Zone	10.92625	0.01601	0.3752	0.4127
15	Richmound	To	Western Zone	17.53628	0.02679	0.6033	0.6636
16	Richmound	To	Northern Zone	27.03762	0.04229	0.9312	1.0243
17	Richmound	To	Eastern Zone	35.12817	0.05548	1.2104	1.3314
18	Richmound	To	Southwest Zone	29.90148	0.04696	1.0300	1.1330
19	Bayhurst	To	Sask. Zone	6.59638	0.00894	0.2258	0.2484
20	Bayhurst	To	Manitoba Zone	10.61492	0.01550	0.3645	0.4010
21	Bayhurst	To	Western Zone	17.22495	0.02628	0.5926	0.6519
22	Bayhurst	To	Northern Zone	26.72629	0.04178	0.9205	1.0126
23	Bayhurst	To	Eastern Zone	34.82247	0.05497	1.1998	1.3198
24	Bayhurst	To	Southwest Zone	29.59015	0.04645	1.0193	1.1212
25	Liebenthal	To	Sask. Zone	6.44973	0.00871	0.2208	0.2429
26	Liebenthal	To	Manitoba Zone	10.46828	0.01526	0.3594	0.3953
27	Liebenthal	To	Western Zone	17.07831	0.02604	0.5875	0.6463
28	Liebenthal	To	Northern Zone	26.57964	0.04154	0.9154	1.0069
29	Liebenthal	To	Eastern Zone	34.67019	0.05474	1.1946	1.3141
30	Liebenthal	To	Southwest Zone	29.44350	0.04621	1.0142	1.1156
31	Shackleton	To	Sask. Zone	5.90719	0.00782	0.2020	0.2222
32	Shackleton	To	Manitoba Zone	9.92574	0.01438	0.3407	0.3748
33	Shackleton	To	Western Zone	16.53577	0.02516	0.5688	0.6257
34	Shackleton	To	Northern Zone	26.03711	0.04065	0.8967	0.9864
35	Shackleton	To	Eastern Zone	34.12766	0.05385	1.1759	1.2935
36	Shackleton	To	Southwest Zone	28.90097	0.04533	0.9955	1.0951
37	Success	To	Sask. Zone	5.43261	0.00705	0.1857	0.2043
38	Success	To	Manitoba Zone	9.45116	0.01360	0.3243	0.3567
39	Success	To	Western Zone	16.06119	0.02438	0.5524	0.6076
40	Success	To	Northern Zone	25.56253	0.03988	0.8803	0.9683
41	Success	To	Eastern Zone	33.65308	0.05308	1.1595	1.2755
42	Success	To	Southwest Zone	28.42639	0.04455	0.9791	1.0770
43	Herbert	To	Sask. Zone	5.27230	0.00601	0.1794	0.1973
44	Herbert	To	Manitoba Zone	8.81787	0.01257	0.3025	0.3328
45	Herbert	To	Western Zone	15.42790	0.02335	0.5306	0.5837
46	Herbert	To	Northern Zone	24.92924	0.03885	0.8584	0.9442
47	Herbert	To	Eastern Zone	33.02540	0.05204	1.1378	1.2516
48	Herbert	To	Southwest Zone	27.79310	0.04352	0.9573	1.0530
49	Steelman	To	Sask. Zone	2.68286	0.00256	0.0908	0.0999
50	Steelman	To	Manitoba Zone	6.70141	0.00912	0.2294	0.2523
51	Steelman	To	Western Zone	13.31144	0.01990	0.4575	0.5033
52	Steelman	To	Northern Zone	22.81278	0.03540	0.7854	0.8639
53	Steelman	To	Eastern Zone	30.90332	0.04859	1.0646	1.1711
54	Steelman	To	Southwest Zone	25.67664	0.04007	0.8842	0.9726
55	Welwyn	To	Manitoba Zone	4.30560	0.00501	0.1466	0.1613
56	Welwyn	To	Western Zone	10.79200	0.01579	0.3706	0.4077
57	Welwyn	To	Northern Zone	20.29334	0.03129	0.6985	0.7684
58	Welwyn	To	Eastern Zone	28.38389	0.04448	0.9776	1.0754
59	Welwyn	To	Southwest Zone	23.15720	0.03596	0.7973	0.8770

PROPOSED INTERRUPTIBLE TRANSPORTATION SERVICE TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	RECEIPT POINT		DELIVERY POINT	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	(100% LF Toll) ($/GJ)	(1) IT Bid Floor (110% of FT Toll) ($/GJ)
	Long Haul Export						
1	Empress	To	Spruce	12.20490	0.01809	0.4193	0.4612
2	Empress	To	Emerson	12.43842	0.01847	0.4274	0.4701
3	Empress	To	St. Clair	29.77365	0.04675	1.0256	1.1282
4	Empress	To	Niagara Falls	34.78668	0.05493	1.1986	1.3185
5	Empress	To	Chippawa	34.81313	0.05497	1.1995	1.3195
6	Empress	To	Iroquois	34.53970	0.05452	1.1901	1.3091
7	Empress	To	Cornwall	35.53944	0.05615	1.2246	1.3470
8	Empress	To	Philipsburg	37.46831	0.05930	1.2911	1.4202
9	Empress	To	Napierville	37.27506	0.05898	1.2845	1.4129
10	Empress	To	East Hereford	39.51536	0.06264	1.3618	1.4980
11	Suffield	To	Spruce	12.18243	0.01806	0.4186	0.4605
12	Suffield	To	Emerson	12.41596	0.01844	0.4266	0.4693
13	Suffield	To	St. Clair	29.75118	0.04671	1.0248	1.1273
14	Suffield	To	Niagara Falls	34.76427	0.05489	1.1978	1.3176
15	Suffield	To	Chippawa	34.79072	0.05493	1.1987	1.3186
16	Suffield	To	Iroquois	34.51724	0.05449	1.1893	1.3082
17	Suffield	To	Cornwall	35.51797	0.05612	1.2238	1.3462
18	Suffield	To	Napierville	37.25260	0.05895	1.2837	1.4121
19	Suffield	To	Philipsburg	37.44584	0.05926	1.2904	1.4194
20	Suffield	To	East Hereford	39.49026	0.06260	1.3609	1.4970
21	Richmound	To	Spruce	12.18033	0.01805	0.4185	0.4604
22	Richmound	To	Emerson	12.41385	0.01843	0.4266	0.4693
23	Richmound	To	St. Clair	29.74908	0.04671	1.0248	1.1273
24	Richmound	To	Niagara Falls	34.76216	0.05489	1.1978	1.3176
25	Richmound	To	Chippawa	34.78862	0.05493	1.1987	1.3186
26	Richmound	To	Iroquois	34.51513	0.05448	1.1892	1.3081
27	Richmound	To	Cornwall	35.51587	0.05612	1.2238	1.3462
28	Richmound	To	Napierville	37.25050	0.05894	1.2836	1.4120
29	Richmound	To	Philipsburg	37.44374	0.05926	1.2903	1.4193
30	Richmound	To	East Hereford	39.48815	0.06259	1.3608	1.4969
31	Bayhurst	To	Spruce	11.86899	0.01754	0.4078	0.4486
32	Bayhurst	To	Emerson	12.10252	0.01793	0.4158	0.4574
33	Bayhurst	To	St. Clair	29.43775	0.04620	1.0140	1.1154
34	Bayhurst	To	Niagara Falls	34.45083	0.05438	1.1870	1.3057
35	Bayhurst	To	Chippawa	34.47728	0.05442	1.1879	1.3067
36	Bayhurst	To	Iroquois	34.20380	0.05398	1.1785	1.2964
37	Bayhurst	To	Cornwall	35.20454	0.05561	1.2130	1.3343
38	Bayhurst	To	Napierville	36.93917	0.05844	1.2729	1.4002
39	Bayhurst	To	Philipsburg	37.13241	0.05875	1.2795	1.4075
40	Bayhurst	To	East Hereford	39.17682	0.06209	1.3501	1.4851
41	Liebenthal	To	Spruce	11.72235	0.01731	0.4027	0.4430
42	Liebenthal	To	Emerson	11.95588	0.01769	0.4108	0.4519
43	Liebenthal	To	St. Clair	0.00000	0.04596	0.0460	0.0506
44	Liebenthal	To	Niagara Falls	0.00000	0.05414	0.0541	0.0595
45	Liebenthal	To	Chippawa	0.00000	0.05418	0.0542	0.0596
46	Liebenthal	To	Iroquois	0.00000	0.05374	0.0537	0.0591
47	Liebenthal	To	Cornwall	0.00000	0.05537	0.0554	0.0609
48	Liebenthal	To	Napierville	36.79252	0.05820	1.2678	1.3946
49	Liebenthal	To	Philipsburg	36.98576	0.05851	1.2745	1.4020
50	Liebenthal	To	East Hereford	39.03017	0.06185	1.3450	1.4795

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LINE NO.	RECEIPT POINT		DELIVERY POINT	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	(100% LF Toll) ($/GJ)	(1) IT Bid Floor (110% of FT Toll) ($/GJ)
	Long Haul Export (continued)						
1	Shackleton	To	Spruce	11.17981	0.01642	0.3840	0.4224
2	Shackleton	To	Emerson	11.41334	0.01680	0.3920	0.4312
3	Shackleton	To	St. Clair	28.74857	0.04508	0.9902	1.0892
4	Shackleton	To	Niagara Falls	33.76165	0.05325	1.1632	1.2795
5	Shackleton	To	Chippawa	33.78810	0.05330	1.1641	1.2805
6	Shackleton	To	Iroquois	33.51462	0.05285	1.1547	1.2702
7	Shackleton	To	Cornwall	34.51536	0.05448	1.1892	1.3081
9	Shackleton	To	Napierville	36.24999	0.05731	1.2491	1.3740
10	Shackleton	To	Philipsburg	36.44323	0.05763	1.2558	1.3814
11	Shackleton	To	East Hereford	38.48764	0.06096	1.3263	1.4589
12	Success	To	Spruce	10.70523	0.01565	0.3676	0.4044
13	Success	To	Emerson	10.93876	0.01603	0.3757	0.4133
14	Success	To	St. Clair	28.27399	0.04430	0.9739	1.0713
15	Success	To	Niagara Falls	33.28707	0.05248	1.1468	1.2615
16	Success	To	Chippawa	33.31352	0.05252	1.1478	1.2626
17	Success	To	Iroquois	33.04004	0.05208	1.1383	1.2521
18	Success	To	Cornwall	34.04078	0.05371	1.1729	1.2902
20	Success	To	Napierville	35.77541	0.05654	1.2327	1.3560
21	Success	To	Philipsburg	35.96865	0.05685	1.2394	1.3633
22	Success	To	East Hereford	38.01306	0.06019	1.3099	1.4409
23	Herbert	To	Spruce	10.07194	0.01461	0.3457	0.3803
24	Herbert	To	Emerson	10.30547	0.01499	0.3538	0.3892
25	Herbert	To	St. Clair	27.64070	0.04327	0.9520	1.0472
26	Herbert	To	Niagara Falls	32.65378	0.05145	1.1250	1.2375
27	Herbert	To	Chippawa	32.68023	0.05149	1.1259	1.2385
28	Herbert	To	Iroquois	32.40675	0.05104	1.1165	1.2282
29	Herbert	To	Cornwall	33.40749	0.05268	1.1510	1.2661
30	Herbert	To	Napierville	35.14212	0.05551	1.2109	1.3320
31	Herbert	To	Philipsburg	35.33536	0.05582	1.2175	1.3393
32	Herbert	To	East Hereford	37.37977	0.05916	1.2881	1.4169
33	Steelman	To	Spruce	7.95548	0.01116	0.2727	0.3000
34	Steelman	To	Emerson	8.18901	0.01154	0.2808	0.3089
35	Steelman	To	St. Clair	25.52424	0.03982	0.8790	0.9669
36	Steelman	To	Niagara Falls	30.53732	0.04799	1.0520	1.1572
37	Steelman	To	Chippawa	30.56377	0.04804	1.0529	1.1582
38	Steelman	To	Iroquois	30.29029	0.04759	1.0434	1.1477
39	Steelman	To	Cornwall	31.29102	0.04922	1.0780	1.1858
40	Steelman	To	Napierville	33.02565	0.05205	1.1378	1.2516
41	Steelman	To	Philipsburg	33.21892	0.05237	1.1445	1.2590
42	Steelman	To	East Hereford	35.26331	0.05570	1.2150	1.3365
43	Welwyn	To	Spruce	5.43605	0.00705	0.1858	0.2044
44	Welwyn	To	Emerson	5.66957	0.00743	0.1938	0.2132
45	Welwyn	To	St. Clair	23.00480	0.03571	0.7920	0.8712
46	Welwyn	To	Niagara Falls	28.01788	0.04389	0.9650	1.0615
47	Welwyn	To	Chippawa	28.04433	0.04393	0.9659	1.0625
48	Welwyn	To	Iroquois	27.77085	0.04348	0.9565	1.0522
49	Welwyn	To	Cornwall	28.77159	0.04511	0.9910	1.0901
50	Welwyn	To	Napierville	30.50622	0.04794	1.0509	1.1560
51	Welwyn	To	Philipsburg	30.69946	0.04826	1.0576	1.1634
52	Welwyn	To	East Hereford	32.74387	0.05159	1.1281	1.2409

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	Short Haul Tolls						
1	Emerson	To	Centrat MDA	2.68315	0.00256	0.0908	0.0999
2	Emerson	To	TCPL NDA	16.45963	0.02503	0.5662	0.6228
3	Emerson	To	TCPL WDA	9.91700	0.01436	0.3404	0.3744
4	Emerson	To	TPLP NDA	13.57750	0.02033	0.4667	0.5134
5	Emerson	To	Union SWDA	18.50050	0.02836	0.6366	0.7003
6	Emerson	To	Enbridge SWDA	18.71034	0.02870	0.6438	0.7082
7	Emerson	To	Union CDA	21.23055	0.03281	0.7308	0.8039
8	Emerson	To	Enbridge CDA	22.03627	0.03413	0.7586	0.8345
9	Emerson	To	Enbridge EDA	24.64635	0.03839	0.8487	0.9336
10	Emerson	To	Union NCDA	22.11065	0.03425	0.7612	0.8373
11	Emerson	To	Union EDA	24.51808	0.03818	0.8443	0.9287
12	Emerson	To	Union NDA	18.00101	0.02755	0.6194	0.6813
13	Emerson	To	Union WDA	7.89217	0.01106	0.2705	0.2976
14	Emerson	To	Union SSMDA	13.78945	0.02068	0.4740	0.5214
15	Emerson	To	KPUC EDA	24.58382	0.03828	0.8465	0.9312
16	Emerson	To	GMi EDA	27.11952	0.04242	0.9340	1.0274
17	Emerson	To	GMi NDA	19.10213	0.02934	0.6574	0.7231
18	Emerson	To	Spruce	2.68315	0.00256	0.0908	0.0999
19	Emerson	To	St. Clair	18.44660	0.02827	0.6347	0.6982
20	Emerson	To	Niagara Falls	22.03882	0.03413	0.7587	0.8346
21	Emerson	To	Chippawa	22.06416	0.03417	0.7596	0.8356
22	Emerson	To	Iroquois	24.92869	0.03885	0.8584	0.9442
23	Emerson	To	Cornwall	25.26459	0.03939	0.8700	0.9570
24	Emerson	To	Napierville	27.00021	0.04223	0.9299	1.0229
25	Emerson	To	Philipsburg	27.19346	0.04254	0.9366	1.0303
26	Emerson	To	East Hereford	29.24052	0.04588	1.0072	1.1079
27	Dawn	To	Centrat MDA	20.28095	0.03127	0.6980	0.7678
28	Dawn	To	TCPL NDA	11.30421	0.01662	0.3883	0.4271
29	Dawn	To	TCPL WDA	17.84684	0.02730	0.6140	0.6754
30	Dawn	To	TPLP NDA	14.18622	0.02132	0.4877	0.5365
31	Dawn	To	Union CDA	3.68603	0.00411	0.1253	0.1378
32	Dawn	To	Enbridge CDA	4.47593	0.00543	0.1526	0.1678
33	Dawn	To	Enbridge EDA	8.79297	0.01257	0.3017	0.3318
34	Dawn	To	GMi NDA	9.00082	0.01287	0.3088	0.3397
35	Dawn	To	GMi EDA	10.45499	0.01553	0.3593	0.3952
36	Dawn	To	KPUC EDA	6.98596	0.00958	0.2393	0.2632
37	Dawn	To	Union NCDA	5.65164	0.00740	0.1932	0.2125
38	Dawn	To	Union EDA	7.20077	0.00995	0.2467	0.2714
39	Dawn	To	Union NDA	9.76260	0.01411	0.3351	0.3686
40	Dawn	To	Union SSMDA	7.84713	0.01098	0.2690	0.2959
41	Dawn	To	Union WDA	20.13297	0.03102	0.6929	0.7622
42	Dawn	To	Spruce	20.28095	0.03127	0.6980	0.7678
42	Dawn	To	Niagara Falls	4.43996	0.00543	0.1514	0.1665
43	Dawn	To	Chippawa	4.46641	0.00547	0.1523	0.1675
44	Dawn	To	Iroquois	8.34563	0.01180	0.2862	0.3148
45	Dawn	To	Cornwall	8.78079	0.01251	0.3012	0.3313
46	Dawn	To	Napierville	10.51642	0.01534	0.3611	0.3972
47	Dawn	To	Philipsburg	10.70966	0.01565	0.3677	0.4045
48	Dawn	To	East Hereford	12.75684	0.01899	0.4384	0.4822

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	Short Haul Tolls (continued)						
1	Sault Ste. Marie	To	Centrat MDA	15.24042	0.02304	0.5241	0.5765
2	Sault Ste. Marie	To	TCPL NDA	17.91856	0.02741	0.6165	0.6782
3	Sault Ste. Marie	To	TCPL WDA	22.47433	0.03484	0.7737	0.8511
4	Sault Ste. Marie	To	TPLP NDA	20.80057	0.03211	0.7160	0.7876
5	Sault Ste. Marie	To	Union SWDA	7.51698	0.01045	0.2576	0.2834
6	Sault Ste. Marie	To	Enbridge SWDA	7.72682	0.01079	0.2648	0.2913
7	Sault Ste. Marie	To	Union CDA	10.24703	0.01490	0.3518	0.3870
8	Sault Ste. Marie	To	Enbridge CDA	11.05364	0.01622	0.3796	0.4176
9	Sault Ste. Marie	To	Enbridge EDA	15.43177	0.02336	0.5307	0.5838
10	Sault Ste. Marie	To	Union NCDA	12.13993	0.01799	0.4171	0.4588
11	Sault Ste. Marie	To	Union NDA	16.37219	0.02489	0.5632	0.6195
12	Sault Ste. Marie	To	Union WDA	20.78718	0.03209	0.7155	0.7871
13	Sault Ste. Marie	To	Union SSMDA	1.23212	0.00020	0.0407	0.0448
14	Sault Ste. Marie	To	Union EDA	13.65996	0.02047	0.4696	0.5166
15	Sault Ste. Marie	To	KPUC EDA	13.60030	0.02037	0.4675	0.5143
16	Sault Ste. Marie	To	GMi EDA	17.25008	0.02632	0.5934	0.6527
17	Sault Ste. Marie	To	GMi NDA	15.61517	0.02366	0.5370	0.5907
18	Sault Ste. Marie	To	Spruce	15.24042	0.02304	0.5241	0.5765
19	Sault Ste. Marie	To	Niagara Falls	11.05420	0.01622	0.3796	0.4176
20	Sault Ste. Marie	To	Chippawa	11.08065	0.01626	0.3806	0.4187
21	Sault Ste. Marie	To	Iroquois	14.95996	0.02259	0.5144	0.5658
22	Sault Ste. Marie	To	Cornwall	15.39514	0.02330	0.5294	0.5823
23	Sault Ste. Marie	To	Napierville	17.13043	0.02613	0.5893	0.6482
24	Sault Ste. Marie	To	Philipsburg	17.32401	0.02644	0.5960	0.6556
25	Sault Ste. Marie	To	East Hereford	19.37108	0.02978	0.6666	0.7333
26	St. Clair	To	Centrat MDA	20.01720	0.03084	0.6889	0.7578
27	St. Clair	To	TCPL NDA	11.56795	0.01705	0.3974	0.4371
28	St. Clair	To	TCPL WDA	18.11058	0.02773	0.6231	0.6854
29	St. Clair	To	TPLP NDA	14.44997	0.02175	0.4968	0.5465
30	St. Clair	To	Union SWDA	1.19858	0.00009	0.0395	0.0435
31	St. Clair	To	Enbridge SWDA	1.37622	0.00043	0.0457	0.0503
32	St. Clair	To	Union CDA	3.89643	0.00454	0.1326	0.1459
33	St. Clair	To	Enbridge CDA	4.70304	0.00586	0.1605	0.1766
34	St. Clair	To	Enbridge EDA	9.10718	0.01304	0.3125	0.3438
35	St. Clair	To	Union NCDA	5.91538	0.00783	0.2023	0.2225
36	St. Clair	To	Union NDA	10.02634	0.01454	0.3442	0.3786
37	St. Clair	To	Union WDA	20.35930	0.03139	0.7007	0.7708
38	St. Clair	To	Union SSMDA	7.58339	0.01055	0.2599	0.2859
39	St. Clair	To	Union EDA	7.47692	0.01038	0.2562	0.2818
40	St. Clair	To	KPUC EDA	7.24970	0.01001	0.2484	0.2732
41	St. Clair	To	GMi EDA	10.89947	0.01596	0.3743	0.4117
42	St. Clair	To	GMi NDA	9.26456	0.01330	0.3179	0.3497
43	St. Clair	To	Spruce	20.01720	0.03084	0.6889	0.7578
44	St. Clair	To	Niagara Falls	4.69359	0.00586	0.1602	0.1762
45	St. Clair	To	Chippawa	4.73004	0.00590	0.1614	0.1775
46	St. Clair	To	Iroquois	8.60936	0.01223	0.2953	0.3248
47	St. Clair	To	Cornwall	9.04454	0.01294	0.3103	0.3413
48	St. Clair	To	Napierville	10.78016	0.01577	0.3702	0.4072
49	St. Clair	To	Philipsburg	10.97340	0.01608	0.3768	0.4145
50	St. Clair	To	East Hereford	13.02047	0.01942	0.4475	0.4923

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	Short Haul Tolls (continued)						
1	Parkway	To	Centrat MDA	22.79197	0.03536	0.7847	0.8632
2	Parkway	To	Union WDA	17.75421	0.02714	0.6108	0.6719
3	Parkway	To	Union NDA	7.25158	0.01001	0.2484	0.2732
4	Parkway	To	Union SSMDA	10.35826	0.01508	0.3556	0.3912
5	Parkway	To	TCPL NDA	8.79319	0.01253	0.3016	0.3318
6	Parkway	To	TCPL WDA	15.33582	0.02320	0.5274	0.5801
7	Parkway	To	TPLP NDA	11.67520	0.01723	0.4011	0.4412
8	Parkway	To	GMi NDA	6.48979	0.00877	0.2221	0.2443
9	Parkway	To	Union CDA	1.19061	0.00013	0.0393	0.0432
10	Parkway	To	Union SWDA	3.83334	0.00444	0.1305	0.1436
11	Parkway	To	Enbridge CDA	1.92827	0.00133	0.0647	0.0712
12	Parkway	To	Enbridge EDA	6.30651	0.00847	0.2158	0.2374
13	Parkway	To	Enbridge SWDA	3.62350	0.00410	0.1232	0.1355
14	Parkway	To	Union NCDA	3.14062	0.00331	0.1066	0.1173
15	Parkway	To	Union EDA	4.70215	0.00586	0.1605	0.1766
16	Parkway	To	KPUC EDA	4.47493	0.00548	0.1526	0.1679
17	Parkway	To	GMi EDA	8.12493	0.01144	0.2786	0.3065
18	Parkway	To	Spruce	22.79197	0.03536	0.7847	0.8632
19	Parkway	To	Emerson	21.22136	0.03280	0.7305	0.8036
20	Parkway	To	St. Clair	3.88724	0.00453	0.1323	0.1455
21	Parkway	To	Niagara Falls	2.58126	0.00240	0.0873	0.0960
22	Parkway	To	Chippawa	2.60771	0.00244	0.0882	0.0970
23	Parkway	To	Iroquois	5.83459	0.00770	0.1995	0.2195
24	Parkway	To	Cornwall	6.26977	0.00841	0.2145	0.2360
25	Parkway	To	Napierville	8.00540	0.01124	0.2744	0.3018
26	Parkway	To	Philipsburg	8.19864	0.01156	0.2811	0.3092
27	Parkway	To	East Hereford	10.24582	0.01490	0.3517	0.3869
28	Kirkwall	To	Centrat MDA	22.36908	0.03467	0.7701	0.8471
29	Kirkwall	To	Union WDA	18.17799	0.02784	0.6255	0.6881
30	Kirkwall	To	Union NDA	7.67447	0.01070	0.2367	0.2604
31	Kirkwall	To	Union SSMDA	9.93526	0.01439	0.3410	0.3751
32	Kirkwall	To	TCPL NDA	9.21608	0.01792	0.4157	0.4573
33	Kirkwall	To	TCPL WDA	15.75871	0.02389	0.5420	0.5962
34	Kirkwall	To	TPLP NDA	12.09809	0.01792	0.4157	0.4573
35	Kirkwall	To	GMi NDA	6.91269	0.00946	0.2367	0.2604
36	Kirkwall	To	Union CDA	1.54456	0.00070	0.0515	0.0567
37	Kirkwall	To	Enbridge CDA	2.35117	0.00202	0.0793	0.0872
38	Kirkwall	To	Enbridge EDA	6.72941	0.00916	0.2304	0.2534
39	Kirkwall	To	Union NCDA	3.56351	0.00400	0.1212	0.1333
40	Kirkwall	To	Union EDA	5.12505	0.00654	0.1750	0.1925
41	Kirkwall	To	KPUC EDA	4.89783	0.00617	0.1672	0.1839
42	Kirkwall	To	GMi EDA	8.54760	0.01213	0.2931	0.3224
43	Kirkwall	To	Spruce	22.36908	0.03467	0.7701	0.8471
44	Kirkwall	To	Niagara Falls	2.35183	0.00202	0.0793	0.0872
45	Kirkwall	To	Chippawa	2.37828	0.00206	0.0803	0.0883
46	Kirkwall	To	Iroquois	6.25749	0.00839	0.2141	0.2355
47	Kirkwall	To	Cornwall	6.69266	0.00910	0.2291	0.2520
48	Kirkwall	To	Napierville	8.42829	0.01193	0.2890	0.3179
49	Kirkwall	To	Philipsburg	8.62153	0.01225	0.2957	0.3253
50	Kirkwall	To	East Hereford	10.66871	0.01559	0.3663	0.4029

PROPOSED INTERRUPTIBLE TRANSPORTATION SERVICE TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	RECEIPT POINT		DELIVERY POINT	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	(100% LF Toll) ($/GJ)	(1) IT Bid Floor (110% of FT Toll) ($/GJ)
	Short Haul Tolls (continued)						
1	Niagara Falls	To	Centrat MDA	23.60843	0.03669	0.8129	0.8942
2	Niagara Falls	To	Union WDA	19.22310	0.02954	0.6615	0.7277
3	Niagara Falls	To	Union NDA	8.72036	0.01241	0.2991	0.3290
4	Niagara Falls	To	Union SSMDA	11.17461	0.01641	0.3838	0.4222
5	Niagara Falls	To	TCPL NDA	10.26197	0.01492	0.3523	0.3875
6	Niagara Falls	To	TCPL WDA	16.80460	0.02560	0.5781	0.6359
7	Niagara Falls	To	TPLP NDA	13.14399	0.01962	0.4518	0.4970
8	Niagara Falls	To	GMi NDA	7.95858	0.01117	0.2728	0.3001
9	Niagara Falls	To	Union CDA	2.51895	0.00229	0.0851	0.0936
10	Niagara Falls	To	Enbridge CDA	2.96885	0.00303	0.1006	0.1107
11	Niagara Falls	To	Enbridge EDA	7.77530	0.01087	0.2665	0.2932
12	Niagara Falls	To	Union NCDA	4.60940	0.00570	0.1572	0.1729
13	Niagara Falls	To	Union EDA	6.17094	0.00825	0.2111	0.2322
14	Niagara Falls	To	KPUC EDA	5.94377	0.00788	0.2033	0.2236
15	Niagara Falls	To	GMi EDA	9.59349	0.01383	0.3292	0.3621
16	Niagara Falls	To	Spruce	23.60843	0.03669	0.8129	0.8942
17	Niagara Falls	To	Chippawa	1.54046	0.00070	0.0513	0.0564
18	Niagara Falls	To	Iroquois	7.30338	0.01010	0.2502	0.2752
19	Niagara Falls	To	Cornwall	7.73856	0.01081	0.2652	0.2917
20	Niagara Falls	To	Napierville	9.47429	0.01364	0.3251	0.3576
21	Niagara Falls	To	Philipsburg	9.66742	0.01395	0.3318	0.3650
22	Niagara Falls	To	East Hereford	11.71449	0.01729	0.4024	0.4426
23	Chippawa	To	Centrat MDA	23.63488	0.03674	0.8138	0.8952
24	Chippawa	To	Union WDA	19.24955	0.02958	0.6624	0.7286
25	Chippawa	To	Union NDA	8.74682	0.01245	0.3000	0.3300
26	Chippawa	To	Union SSMDA	11.20106	0.01646	0.3847	0.4232
27	Chippawa	To	TCPL NDA	10.28843	0.01497	0.3532	0.3885
28	Chippawa	To	TCPL WDA	16.83106	0.02564	0.5790	0.6369
29	Chippawa	To	TPLP NDA	13.17044	0.01967	0.4527	0.4980
30	Chippawa	To	GMi NDA	7.95858	0.01117	0.2479	0.2727
31	Chippawa	To	Union CDA	2.54540	0.00234	0.0860	0.0946
32	Chippawa	To	Enbridge CDA	3.00305	0.00308	0.1018	0.1120
33	Chippawa	To	Enbridge EDA	7.80175	0.01091	0.2674	0.2941
34	Chippawa	To	Union NCDA	4.63586	0.00575	0.1582	0.1740
35	Chippawa	To	Union EDA	6.19739	0.00829	0.2120	0.2332
36	Chippawa	To	KPUC EDA	5.97028	0.00792	0.2042	0.2246
37	Chippawa	To	GMi EDA	9.25737	0.01329	0.3176	0.3494
38	Chippawa	To	Spruce	23.63488	0.03674	0.8138	0.8952
39	Chippawa	To	Niagara Falls	1.54046	0.00070	0.0513	0.0564
40	Chippawa	To	Iroquois	7.32983	0.01014	0.2511	0.2762
41	Chippawa	To	Cornwall	7.76501	0.01085	0.2661	0.2927
42	Chippawa	To	Napierville	9.50074	0.01368	0.3260	0.3586
43	Chippawa	To	Philipsburg	9.69387	0.01400	0.3327	0.3660
44	Chippawa	To	East Hereford	11.74094	0.01734	0.4033	0.4436

TransCanada
In business to deliver

PROPOSED INTERRUPTIBLE TRANSPORTATION SERVICE TOLLS
PROPOSED TOLLS EFFECTIVE JANUARY 1, 2004

LINE NO.	RECEIPT POINT		DELIVERY POINT	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	(100% LF Toll) ($/GJ)	(1) IT Bid Floor (110% of FT Toll) ($/GJ)
	Short Haul Tolls (continued)						
1	Iroquois	To	Union SSMDA	15.08038	0.02278	0.5186	0.5705
2	Iroquois	To	GMi NDA	7.27814	0.01006	0.2493	0.2742
3	Iroquois	To	Enbridge SWDA	8.34561	0.01180	0.2862	0.3148
4	Iroquois	To	Union SWDA	8.55546	0.01214	0.2934	0.3227
5	Iroquois	To	Union CDA	5.91273	0.00783	0.2022	0.2224
6	Iroquois	To	Enbridge CDA	5.55757	0.00725	0.1900	0.2090
7	Iroquois	To	Enbridge EDA	2.15095	0.00169	0.0724	0.0796
8	Iroquois	To	Union NCDA	6.74446	0.00919	0.2309	0.2540
9	Iroquois	To	Union EDA	2.35393	0.00202	0.0794	0.0873
10	Iroquois	To	KPUC EDA	2.47213	0.00222	0.0835	0.0919
11	Iroquois	To	GMi EDA	3.50165	0.00390	0.1190	0.1309
12	Iroquois	To	Emerson	24.92869	0.03885	0.8584	0.9442
13	Iroquois	To	St. Clair	8.60936	0.01223	0.2953	0.3248
14	Iroquois	To	Niagara Falls	7.30338	0.01010	0.2502	0.2752
15	Iroquois	To	Chippawa	7.32983	0.01014	0.2511	0.2762
16	Iroquois	To	Cornwall	1.64671	0.00087	0.0550	0.0605
17	Iroquois	To	Napierville	3.38234	0.00370	0.1149	0.1264
18	Iroquois	To	Philipsburg	3.57558	0.00402	0.1216	0.1338
19	Iroquois	To	East Hereford	5.62265	0.00736	0.1922	0.2114
20	East Hereford	To	Union SSMDA	19.49149	0.02998	0.6708	0.7379
21	East Hereford	To	GMi NDA	11.59009	0.01709	0.3981	0.4379
22	East Hereford	To	Union SWDA	12.96657	0.01934	0.4456	0.4902
23	East Hereford	To	Enbridge SWDA	12.75684	0.01899	0.4384	0.4822
24	East Hereford	To	Union CDA	10.32395	0.01502	0.3544	0.3898
25	East Hereford	To	Enbridge CDA	9.96879	0.01445	0.3422	0.3764
26	East Hereford	To	Enbridge EDA	6.35300	0.00855	0.2174	0.2391
27	East Hereford	To	Union NCDA	11.13410	0.01635	0.3824	0.4206
28	East Hereford	To	Union EDA	6.67064	0.00907	0.2284	0.2512
29	East Hereford	To	KPUC EDA	6.88325	0.00941	0.2357	0.2593
30	East Hereford	To	GMi EDA	4.56856	0.00564	0.1558	0.1714
31	East Hereford	To	Emerson	29.24052	0.04588	1.0072	1.1079
32	East Hereford	To	St. Clair	13.02047	0.01942	0.4475	0.4923
33	East Hereford	To	Niagara Falls	11.71449	0.01729	0.4024	0.4426
34	East Hereford	To	Chippawa	11.74094	0.01734	0.4033	0.4436
35	East Hereford	To	Iroquois	5.62265	0.00736	0.1922	0.2114
36	East Hereford	To	Napierville	5.41612	0.00702	0.1851	0.2036
37	East Hereford	To	Philipsburg	5.60936	0.00733	0.1917	0.2109
38	Union NDA	To	Enbridge CDA	7.23199	0.00998	0.2477	0.2725
39	Enbridge CDA	To	Union CDA	1.94720	0.00136	0.0654	0.0719
40	Enbridge EDA	To	Union CDA	6.37358	0.00858	0.2181	0.2399
41	Enbridge EDA	To	Enbridge CDA	6.01842	0.00800	0.2059	0.2265
42	Spruce	To	Emerson	2.68315	0.00256	0.0908	0.0999
43	Union NDA	To	Union CDA	7.32961	0.01014	0.2511	0.2762
44	CentraT MDA	To	Union CDA	22.8015	0.0354	0.7850	0.8635

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	Short Haul Tolls (continued)						
1	Enbridge CDA	To	Enbridge EDA	6.0232	0.0080	0.2060	0.2266
2	Enbridge CDA	To	Iroquois	5.5826	0.0073	0.1908	0.2099
3	Enbridge CDA	To	Union EDA	4.4322	0.0054	0.1511	0.1662
4	Enbridge CDA	To	Union NDA	7.2343	0.0100	0.2478	0.2726
5	Enbridge CDA	To	Union WDA	17.7298	0.0271	0.6100	0.6710
6	Enbridge CDA	To	East Hereford	9.9688	0.0145	0.3422	0.3764
7	Enbridge CDA	To	GMIT EDA	7.8477	0.0110	0.2690	0.2959
8	Enbridge CDA	To	Napierville	7.7021	0.0108	0.2640	0.2904
9	Enbridge CDA	To	Niagara Falls	2.9689	0.0030	0.1006	0.1107
10	Enbridge CDA	To	Philipsburg	7.8946	0.0111	0.2706	0.2977
11	Enbridge CDA	To	Union CDA	1.9472	0.0014	0.0654	0.0719
12	Enbridge CDA	To	Union NCDA	3.5082	0.0039	0.1192	0.1312
13	Enbridge EDA	To	East Hereford	6.3530	0.0086	0.2174	0.2392
14	Enbridge EDA	To	GMIT EDA	4.2320	0.0051	0.1442	0.1586
15	Enbridge EDA	To	Iroquois	2.1510	0.0017	0.0724	0.0796
16	Enbridge EDA	To	Union EDA	3.0873	0.0032	0.1047	0.1152
17	Enbridge EDA	To	Union NDA	7.8420	0.0110	0.2688	0.2957
18	Enbridge EDA	To	Union WDA	18.3375	0.0281	0.6310	0.6941
19	Enbridge EDA	To	Napierville	4.1130	0.0049	0.1401	0.1541
20	Enbridge EDA	To	Enbridge CDA	6.0232	0.0080	0.2060	0.2266
21	Enbridge EDA	To	Niagara Falls	7.7753	0.0109	0.2665	0.2931
22	Enbridge EDA	To	Philipsburg	4.3063	0.0052	0.1468	0.1615
23	Enbridge EDA	To	Union CDA	6.3828	0.0086	0.2184	0.2403
24	Enbridge EDA	To	Union NCDA	6.8570	0.0094	0.2348	0.2583
25	GMIT EDA	To	Iroquois	3.5016	0.0039	0.1190	0.1309
26	GMIT EDA	To	East Hereford	4.5686	0.0056	0.1558	0.1714
27	GMIT EDA	To	Enbridge CDA	7.8477	0.0110	0.2690	0.2959
28	GMIT EDA	To	Enbridge EDA	4.2320	0.0051	0.1442	0.1586
29	GMIT EDA	To	Union CDA	8.2005	0.0116	0.2812	0.3093
30	GMIT EDA	To	Union EDA	4.5496	0.0056	0.1552	0.1707
31	GMIT EDA	To	Union NDA	10.2363	0.0149	0.3514	0.3866
32	GMIT EDA	To	Union WDA	20.7318	0.0320	0.7136	0.7850
33	GMIT EDA	To	Philipsburg	3.1205	0.0033	0.1059	0.1165
34	GMIT EDA	To	Napierville	2.9735	0.0030	0.1008	0.1109
35	GMIT EDA	To	Niagara Falls	9.5935	0.0138	0.3292	0.3622
36	GMIT EDA	To	Union NCDA	9.2031	0.0132	0.3158	0.3473
37	Union CDA	To	Enbridge CDA	1.9472	0.0014	0.0654	0.0719
38	Union CDA	To	Enbridge EDA	6.3828	0.0086	0.2184	0.2403
39	Union CDA	To	GMIT EDA	8.2005	0.0116	0.2812	0.3093
40	Union CDA	To	Iroquois	5.9127	0.0078	0.2022	0.2224
41	Union CDA	To	Union EDA	4.7572	0.0059	0.1623	0.1786
42	Union CDA	To	Union NDA	7.3296	0.0101	0.2511	0.2762
43	Union CDA	To	Union WDA	17.8323	0.0273	0.6135	0.6749
44	Union CDA	To	East Hereford	10.3240	0.0150	0.3544	0.3899
45	Union CDA	To	Napierville	8.0835	0.0114	0.2771	0.3048
46	Union CDA	To	Niagara Falls	2.5190	0.0023	0.0851	0.0936
47	Union CDA	To	Philipsburg	8.2768	0.0117	0.2838	0.3122
48	Union CDA	To	Union NCDA	3.5001	0.0039	0.1190	0.1309

PROPOSED INTERRUPTIBLE TRANSPORTATION SERVICE TOLLS
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LINE NO.	RECEIPT POINT		DELIVERY POINT	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	(100% LF Toll) ($/GJ)	(1) IT Bid Floor (110% of FT Toll) ($/GJ)
	Short Haul Tolls (continued)						
1	Union EDA	To	East Hereford	6.6706	0.0091	0.2284	0.2512
2	Union EDA	To	Enbridge EDA	3.0873	0.0032	0.1047	0.1152
3	Union EDA	To	Iroquois	2.3539	0.0020	0.0794	0.0874
4	Union EDA	To	Union NDA	8.7930	0.0125	0.3016	0.3318
5	Union EDA	To	Union WDA	19.2884	0.0297	0.6638	0.7302
6	Union EDA	To	Napierville	4.4303	0.0054	0.1511	0.1662
7	Union EDA	To	Enbridge CDA	4.4322	0.0054	0.1511	0.1662
8	Union EDA	To	GMIT EDA	4.5496	0.0056	0.1552	0.1707
9	Union EDA	To	Niagara Falls	6.1709	0.0083	0.2111	0.2322
10	Union EDA	To	Philipsburg	4.6236	0.0057	0.1577	0.1735
11	Union EDA	To	Union CDA	4.7572	0.0059	0.1623	0.1786
12	Union EDA	To	Union NCDA	5.6695	0.0074	0.1938	0.2132
13	Union NCDA	To	Union CDA	3.5001	0.0039	0.1190	0.1309
14	Union NDA	To	Enbridge EDA	7.8420	0.0110	0.2688	0.2957
15	Union NDA	To	GMIT EDA	10.2363	0.0149	0.3514	0.3866
16	Union NDA	To	Iroquois	8.0398	0.0113	0.2756	0.3032
17	Union NDA	To	Union CDA	7.3296	0.0101	0.2511	0.2762
18	Union NDA	To	Union EDA	8.7930	0.0125	0.3016	0.3318
19	Union NDA	To	Union WDA	11.6079	0.0171	0.3987	0.4386
20	Union NDA	To	East Hereford	12.3517	0.0183	0.4244	0.4669
21	Union NDA	To	Enbridge CDA	7.2343	0.0100	0.2478	0.2726
22	Union NDA	To	Napierville	10.1115	0.0147	0.3471	0.3818
23	Union NDA	To	Niagara Falls	8.7204	0.0124	0.2991	0.3290
24	Union NDA	To	Philipsburg	10.3046	0.0150	0.3538	0.3891
25	Union NDA	To	Union NCDA	4.9493	0.0063	0.1690	0.1859
26	Union SSMDA	To	Union CDA	10.3667	0.0151	0.3559	0.3915
27	Union WDA	To	Enbridge CDA	17.7298	0.0271	0.6100	0.6710
28	Union WDA	To	Union CDA	17.8323	0.0273	0.6135	0.6749
29	Union WDA	To	Union NDA	11.6079	0.0171	0.3987	0.4386
30	Union WDA	To	East Hereford	22.4639	0.0348	0.7734	0.8507
31	Union WDA	To	Enbridge EDA	18.3375	0.0281	0.6310	0.6941
32	Union WDA	To	GMIT EDA	20.7318	0.0320	0.7136	0.7850
33	Union WDA	To	Iroquois	18.1521	0.0278	0.6246	0.6870
34	Union WDA	To	Napierville	20.2237	0.0312	0.6961	0.7657
35	Union WDA	To	Niagara Falls	19.2231	0.0295	0.6615	0.7277
36	Union WDA	To	Philipsburg	20.4169	0.0315	0.7027	0.7730
37	Union WDA	To	Union EDA	19.2884	0.0297	0.6638	0.7302
38	Union WDA	To	Union NCDA	15.4447	0.0234	0.5312	0.5843

(1) Nominations for Interruptible Transportation Service will be no less than 110% of the 100% load factor FT toll for the applicable Domestic or Export
(2) Nominations for Interruptible Transportation will be subject to minimum increments of $0.0001/GJ as per Tolls Task Force Resolution 09.98 and approved by National Energy Board letter dated July 14, 1998.

2004 Mainline Tolls and Tariff Application
February 2004 Update

PART X REQUIREMENTS

2004 Mainline Tolls and Tariff Application
February 2004 Update

PART X REQUIREMENTS
S.20

FOR THE ACTUAL YEAR ENDED DECEMBER 31,2003
SECTION 20 (1) EXPLANATORY, ($000)

	Board Order Number	Additions to GPIS	
1) Facilities approved prior to 2002 with completion costs in 2002 and 2003 with the addition of any GPUC balance as of December 31, 2001			
	GC-84	2	
	GC-85	(1)	I
	GC-92	15	I
	GC-93	39	I
	GC-99	65	I
	XG-T1-52-97	3	I
	XG-T001-37-2000	1,607	I
	XG-T001-17-2001	244	I
	XG-T001-26-2001	112	I
	XG-T001-28-2001	(72)	I
	Total Value	2,015	I
2) Projects approved in 2002			
	MO-09-2002	1,047	I
	XG-T001-10-2002	9	
	XG-T001-26-2002	680	I
	XG-T001-29-2002	12	
	XG-T001-32-2002	112	
	XG-T001-36-2002	1,788	I
	XG-T001-39-2002	10	
	XG-T001-48-2002	1,213	
	XG-T001-53-2002	141	I
	XG-T001-55-2002	6,096	I
	Total Value	11,108	I
3) Projects approved in 2003			
	MO-01-2003	450	I
	XG-T001-04-2003	2,893	I
	XG-T001-19-2003	929	I
	XG-T001-22-2003	202	I
	XG-T001-46-2003	102	I
	Total Value	4,577	I
4) Section 58 projects which do not require an application			
	2000 XG - 100	55	I
	2001 XG - 100	1,152	I
	2002 XG - 100	5,288	I
	2003 XG - 100	5,856	I
	Total Value	12,351	I
5) Emergency Projects approved in 2003		558	I
Total as per Part X, Section 20 (2)(3)		**30,610**	I

I Updated to reflect 2003 actual costs.

TEST YEAR ENDING DECEMBER 31,2004
SECTION 20 (1) EXPLANATORY, ($000)

		Additions to GPIS	
1)	Mains	26,809	I
2)	Compression	18,237	I
3)	Metering	250	I
4)	Communications	544	I
		45,840	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

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($000)

Project Number	Description	Province	Type	CCA Class	Depreciation Rate	Justification Code	NEB Appl No	Board Order No	FDPS	GPUC Dec 31, 2002	Completion Costs	Additions to GPIS	
2042945	Arbitration Ass'd with 1003044	MAN	P	1	2.82	Capacity	GH-3-96	GC-92	199704	0	15	15	I
2043469	Post Const.Recl.- Vermillion T98404	ONT	P	1	2.82	Capacity	GH-2-97	GC-93	199811	0	46	46	I
1001330	T98007 - INSTALL NEW 30.0 MW UNIT S	SASk	C	8	3.99	Capacity	GH-2-97	GC-93	199812	0	(45)	(45)	
1001329	T98002 - INST ONE 30.0 MW UNIT STN	SASk	C	8	3.99	Capacity	GH-2-97	GC-93	199910	0	8	8	I
1001336	T98409 - INSTALL NEW 30.0 MW UNIT S	ONT	C	8	3.99	Capacity	GH-2-97	GC-93	199910	0	8	8	I
2043467	Post Const.Recl.-T99204 INST 25.0KM	MAN	P	1	2.82	Capacity	GH-3-98	GC-99	199912	0	60	60	I
2043468	Post Const.Recl.-T99609 INST19.1KM/	ONT	P	1	2.82	Capacity	GH-3-98	GC-99	199912	0	5	5	I
1001027	Install Low Nox Facilities Station 127B	ONT	C	8	3.99	Capacity	GH-2-93	GC-85	200002	(1)	0	(1)	I
1002376	T00625 - Replace Pipeline MLV: 106	ONT	P	1	2.82	Safety	2000 S.58-05	XG-T001-37-2000	200008	0	1,607	1,607	I
1002640	T00843 - Upgrade Gas Generator Station 127	ONT	C	8	3.99	Economic	2000 XG-100 Appl.	2000 XG-100	200101	(1)	0	(1)	I
2003164	EGT Thermocouple Mod. Station 119B	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200104	(2)	0	(2)	
2014041	Cold weather Starts	ONT	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200106	(16)	0	(16)	I
2020301	Arbitration Ass'd w/Unitized T93403	ONT	P	1	2.82	Capacity	GH-4-92	GC-84	200107	(6)	8	2	
2019761	St. Patrice de Sherrington Tap	QUE	M	8	3.82	Capacity	2001 XG-100 Appl.	2001 XG-100	200109	0	2	2	
2014901	STN 107C PGT25 VENTILATION UPGRADE	ONT	C	8	3.99	Safety	GH-2-97	GC-93	200111	0	8	8	I
2016041	2001 Daniel 2500 Flow Comp U/G:PQ	QUE	M	8	3.82	Economic	2001 XG-100 Appl.	2001 XG-100	200111	0	(10)	(10)	
2002254	2000 CIU Prog.Design-Stn.92	ONT	C	8	3.99	Environmental	2000 S.58-10	XG-T001-26-2001	200112	0	15	15	I
2002258	2000 CIU Program Design-Stn.209	ONT	C	8	3.99	Environmental	2000 S.58-10	XG-T001-26-2001	200112	0	5	5	
2002460	2000 CIU Prog.Design-Stn.95	ONT	C	8	3.99	Environmental	2000 S.58-10	XG-T001-26-2001	200112	0	18	18	
2002461	2000 CIU Prog.Design-Stn.110	ONT	C	8	3.99	Environmental	2000 S.58-10	XG-T001-26-2001	200112	0	34	34	I
2014881	2001 Corrosion Rem.Prog:Toronto(PQ)	QUE	P	1	2.82	Safety	2001 S.58-02	XG-T001-28-2001	200112	0	(72)	(72)	I
2021341	Lube Oil Circulation Pump RB211 Units 2E and F	SASk	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200112	(1)	0	(1)	I
2002242	2000 CIU Program Design-Stn.21	SASk	C	8	3.99	Environmental	2000 S.58-10	XG-T001-26-2001	200201	0	27	27	I
2027581	Addn of Valve Supports, Stn 75	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200202	0	(8)	(8)	
2016803	Station 99B MCC Replacement	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200203	0	2	2	
2017721	Replace Unit Check Valves 148CandD	QUE	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200204	0	(7)	(7)	
2002259	2000 CIU Program Design-Stn.148	QUE	C	8	3.99	Environmental	2000 S.58-10	XG-T001-26-2001	200205	0	12	12	
2025682	Whitewood M/S Upgrade	SASk	M	8	3.82	Functionality	2002 XG-100 Appl.	2002 XG-100	200205	0	4	4	
2026623	CIAC - Selkirk SMS	MAN	M	8	3.82	Capacity	2002 S.58-01	XG-T001-10-2002	200205	0	9	9	
2001262	Unit 41F Contrl Rm HVAC Imp	MAN	C	8	3.99	Functionality	2000 XG-100 Appl.	2000 XG-100	200206	0	6	6	I
2018321	LM1600 Fuel Control Upgrade: 1206B	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200206	0	(48)	(48)	
2029386	C/S 802: 2002 BCI Program	QUE	C	8	3.99	Environmental	2002 XG-100 Appl.	2002 XG-100	200206	0	1	1	
2027341	Kenora East Sales Tap	ONT	M	8	3.82	Capacity	2002 S.58-08	XG-T001-29-2002	200207	0	12	12	
2029581	CIAC: Assiniboine River Sales Tap	MAN	M	8	3.82	Capacity	2002 S.58-09	XG-T001-39-2002	200208	0	10	10	
2031901	147B1&B2:Repl. Exhaust Silencers	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200208	1	(1)	0	I
2032442	Pipeline Rupture:36"MLV 31-32-3	MAN	P	1	2.82	Safety	2002 XG-100 Appl.	2002 XG-100	200208	0	(25)	(25)	
2013841	Fire and Gas Upgrade at Stn.17D	SASk	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200209	0	(57)	(57)	I
2031583	Stn 95 Feed Comp. Air from 95C-95B	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200209	0	1	1	
2028804	Unit34B Vibration Monitor Upgrade	MAN	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200210	0	(1)	(1)	
2032701	Stn 116 - Pilot Fall Protection Prg	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200210	0	(34)	(34)	I
2033501	Stn 75- Feed Compressed Air C-B	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200210	0	1	1	
2034036	Stn 110B Battery Replacements	ONT	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200210	0	8	8	I
2019762	600V Distribution Improvemnts:Stn13	SASk	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200211	0	(7)	(7)	
2023481	Stn130 Units A1,A2,A3 Cntrl. U/G	ONT	C	8	3.99	Safety	2001 XG-100 Appl.	2001 XG-100	200211	0	9	9	
2029562	Pre Wk Borer's Crk X'ing, 208+2.7	ONT	P	1	2.82	Safety	2002 XG-100 Appl.	2002 XG-100	200211	108	(1)	107	I
2035204	Stn.41B,CandD CAT APU Replact	MAN	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200211	0	141	141	I
2035482	Stn1401C Bleed Valve Piping Mod	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200211	0	3	3	
2038241	Stn.80A Decom'g Related Upgds	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200211	0	104	104	

I Updated to reflect 2003 actual costs.

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Project Number	Description	Province	Type	CCA Class	Depreciation Rate	Justification Code	NEB Appl No	Board Order No	FDPS	GPUC Dec 31, 2002	Completion Costs	Additions to GPIS	
2018261	Building Crane Mod.: Stn.80C	ONT	C	8	3.99	Safety	2001 XG-100 Appl.	2001 XG-100	200212	0	12	12	
2018262	Building Crane Mod.: Stn.107C	ONT	C	8	3.99	Safety	2001 XG-100 Appl.	2001 XG-100	200212	0	24	24	I
2021465	Install Demister 88B Plant	ONT	C	8	3.99	Environmental	2001 XG-100 Appl.	2001 XG-100	200212	0	2	2	
2021481	Install Demister 92B	ONT	C	8	3.99	Environmental	2001 XG-100 Appl.	2001 XG-100	200212	0	9	9	
2021482	Install Demister 99B Plant	ONT	C	8	3.99	Environmental	2001 XG-100 Appl.	2001 XG-100	200212	0	5	5	
2023146	Shafer hand pump replacements Const	ONT	P	1	2.82	Safety	2001 XG-100 Appl.	2001 XG-100	200212	51	9	60	I
2026061	Stn147C Solar Centaur Duct Diverter	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200212	0	3	3	
2028185	Parkway meter runs modification	ONT	M	8	3.82	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	(6)	(6)	
2028463	DIF/DDCS Reaplacement Project	AB	M	8	3.82	Economic	2002 XG-100 Appl.	2002 XG-100	200212	57	0	57	I
2029062	Stn.'s211&1301 Inst. Hoisting Equip	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200212	0	2	2	
2029161	119B & 1206A: Inst.Maint.Platforms	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200212	0	9	9	
2029421	2002 CSD Program: Cypress Hills, Sk	SASk	C	8	3.99	Environmental	2002 S.58-05	XG-T001-32-2002	200212	0	(3)	(3)	
2029422	2002 CSD Program: Central Cnd., Sk.	SASk	C	8	3.99	Environmental	2002 S.58-05	XG-T001-32-2002	200212	0	1	1	
2029423	2002 CSD Program: Central Cnd., Mb.	MAN	C	8	3.99	Environmental	2002 S.58-05	XG-T001-32-2002	200212	0	2	2	
2029424	2002 CSD Program: Central Cnd., Ont	ONT	C	8	3.99	Environmental	2002 S.58-05	XG-T001-32-2002	200212	0	(1)	(1)	
2029425	2002 CSD Program: N.Ontario	ONT	C	8	3.99	Environmental	2002 S.58-05	XG-T001-32-2002	200212	0	18	18	
2029703	Stn.62 Install Gas Operator Vents	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200212	16	0	16	I
2029822	MLV86and99, Ledeen Operator Upgrade	ONT	P	1	2.82	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	46	16	61	I
2031181	Stn 60C - Fuel Gas Upgrade	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200212	0	(22)	(22)	I
2031322	Stn 62 Battery Room Vent Upgrade	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200212	1	(4)	(3)	
2031563	Stn 80B - Air Compressor Upgrade	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200212	0	22	22	
2032522	PT Manways: C/S's 2F & 17D	SASk	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200212	0	(23)	(23)	
2032781	Stn 134 RTP Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	1	1	
2032783	Stn 139 RTP Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	2	2	
2032785	Stn 144 RTP Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	5	5	I
2033721	RT56/62 Collector Hatch (ON Units)	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200212	0	(21)	(21)	
2034301	2002 Shafer Hand Pump Repl - Sask	SASk	P	1	2.82	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	44	(0)	43	I
2034303	2002 ShaferHandPump Repl-Manitoba	MAN	P	1	2.82	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	15	0	16	I
2034422	Replace Non-Compliance Tanks	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200212	0	10	10	
2034810	2002 Valve Oper Repl, Mainline	ONT	P	1	2.82	Economic	2002 XG-100 Appl.	2002 XG-100	200212	0	16	16	
2036288	MLV92 1:2UT Valve Operator Repl.	ONT	P	1	2.82	Economic	2002 XG-100 Appl.	2002 XG-100	200212	0	(3)	(3)	
2036742	Upgrade 2H&2J LM2500 DLE FC	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	18	18	I
2037161	UNIT 80C - LM2500 DLE FC Upgrade	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	1	1	
2037422	Stn.13F - LM2500 DLE FC Upgrade	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	11	11	I
2037501	58C & 112C- LM2500 DLE FC Upgrade	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	49	49	I
2037582	77C Plant Upgrade Inlet Strainer	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	46	46	
2037765	Stn 60 Unit Heater Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	6	6	
2038061	HT Rupture Repair, MLV138-139-1	ONT	P	1	2.82	Safety	2002 XG-100 Appl.	2002 XG-100	200212	346	6	352	I
2038223	Stn.5A Decom'g Related Upgds	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200212	0	7	7	
2040567	147A Deactivation	ONT	C	8	3.99	Functionality	2003 OPRs S.44	MO-01-2003	200212	0	91	91	I
	FDPS Total Pre 2003									**658**	**2,194**	**2,852**	
2028481	119 Upgrade Recycle Valve Operators	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200301	10	5	15	
2029144	2002 Corr Rem Prog:SK Cypress Hills	SASk	P	1	2.82	Safety	2002 XG-100 Appl.	XG-T001-48-2002	200301	1,199	14	1,213	
2029147	2002 Corr Rem Prog: ON Central	ONT	P	1	2.82	Safety	2002 XG-100 Appl.	XG-T001-55-2002	200301	2,688	110	2,798	I
2029148	2002 Corr Rem Prog: ON Northern Ont	ONT	P	1	2.82	Safety	2002 XG-100 Appl.	XG-T001-55-2002	200301	1,048	67	1,115	
2029149	2002 Corr Rem Prog: ON Toronto	ONT	P	1	2.82	Safety	2002 XG-100 Appl.	XG-T001-55-2002	200301	2,119	17	2,137	I
2029150	2002 Corr Rem Prog: PQ Toronto	QUE	P	1	2.82	Safety	2002 XG-100 Appl.	XG-T001-55-2002	200301	39	7	46	

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Project Number	Description	Province	Type	CCA Class	Depreciation Rate	Justification Code	NEB Appl No	Board Order No	FDPS	GPUC Dec 31, 2002	Completion Costs	Additions to GPIS	
2029426	2002 CSD Program: Toronto, Ont.	ONT	C	8	3.99	Environmental	2002 S.58-05	XG-T001-32-2002	200301	79	15	94	
2032541	C/S 2: Fall Protection	SASk	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200301	101	4	104	
2033842	Unit 13D Enclosure Fire Dampers	SASk	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200301	0	24	24	
2034441	Stn.2F&G: Waterline Upgrade	SASk	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200301	0	118	118	
2037427	Stn 69 Unit Heater Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200301	0	5	5	
2037441	127B RT62 Rotor & Stg 1/2 Vanes	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200301	1,006	3	1,009	
2039081	Stn 43B1 Mars Combustor Repl.	MAN	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200301	104	0	105	
2039087	Stn.1206A1 PGT 16 PT Casing Upgd:	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200301	388	2	390	
2039101	Stn. 88B1 PGT 16 PT Casing Upgd:	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200301	366	1	368	
2039296	Stn 41 Battery Bank Replacement:	MAN	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200301	0	14	14	
	FDPS Total 200301									**9,150**	**405**	**9,555**	
2017302	Variable Frequency Drive Replace:69	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200302	23	3	26	
2022112	88C: Lube Oil System Mod.	ONT	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200302	5	10	15	
2022116	99C: Lube Oil System Mod.	ONT	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200302	2	6	9	
2028604	Stn.2 Recycle Valve Tank Replace:	SASk	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200302	3	7	10	
2031921	Stn 30 Battery Room Upgrade:	MAN	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	0	8	8	
2033522	Stn 95C: Replace VFD	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200302	11	3	14	
2035068	Station 9E VFD Room Ventilation	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	0	25	25	
2037425	Stn 60A Boiler Replacement:	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	26	(1)	25	
2037767	Stn 58 HVAC Replacement:	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	5	17	21	
2038224	Stn.9A Decom'g Related Upgds	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	4	85	89	
2038762	Stn 49 Unit Heater Replacement:	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	0	11	11	
2038765	Stn 52 Unit Heater Replacement:	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200302	0	10	10	
2040294	Post Const.Reclamation- Winchester	ONT	P	1	2.82	Environmental	GH-2-97	GC-93	200302	0	14	14	I
	FDPS Total 200302									**78**	**199**	**277**	
2038202	13 Main Ctrl Bldg HVAC Repl.	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200303	15	20	35	
2038681	Stn.9&17 Launcher/Reciever:	SASk	P	1	2.82	Safety	2003 S.58-02	XG-T001-04-2003	200303	95	1,301	1,396	I
	FDPS Total 200303									**110**	**1,321**	**1,431**	
2035662	Stn 1301 line 2 Valve Platforms	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200304	3	5	8	
2037204	Stn 5D DJ-270 Rotor Refurb.	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200304	0	503	503	
2037241	Stn.209 - 24V Battery Repl.	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200304	4	2	5	
2037771	147 HVAC Replacement	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200304	(4)	18	15	
2039021	Stn 110C RB211 IP Turbine Casing	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200304	196	8	203	
2039045	Stn.2J PGT 25+ HSPT Upgrade	SASk	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200304	175	80	255	
2039047	Stn.2H PGT 25+ HSPT Upgrade	SASk	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200304	244	(53)	190	
2039049	Stn.13F PGT 25+ HSPT Upgrade	SASk	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200304	281	(78)	203	
2039051	Stn.58C PGT 25+ HSPT Upgrade	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200304	201	16	216	
2039083	123 B1 125V Battery Replacement	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200304	0	12	13	
2039291	Stn.60 Upgd. PPU Cooling System	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200304	0	8	8	I
2039601	Valve Repl. MLV 21 Line 100-2	SASk	P	1	2.82	Safety	2003 XG-100 Appl.	2003 XG-100	200304	0	355	355	I
2040321	Stn 41 Unit Heater Replacement	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200304	0	12	12	
2040970	1401C 125V Battery Repl.	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200304	0	20	20	
2041241	Stn.1211 125V Battery Bank Repl.	ONT	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200304	0	10	10	

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Project Number	Description	Province	Type	CCA Class	Depreciation Rate	Justification Code	NEB Appl No	Board Order No	FDPS	GPUC Dec 31, 2002	Completion Costs	Additions to GPIS	
2041309	Stn.209 125V Battery Repl.	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200304	0	11	11	
2041423	Stn.52B1 Mars Combust. Liner	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200304	0	67	67	I
	FDPS Total 200304									**1,100**	**996**	**2,096**	
1002066	T99661-Fuel Gas Sys Upgr Stn 92	ONT	C	8	3.99	Economic	2000 XG-100 Appl.	2000 XG-100	200305	0	(63)	(63)	I
1002598	T00826 - Upgrade Main Motor Switch	ONT	C	8	3.99	Economic	2000 XG-100 Appl.	2000 XG-100	200305	83	29	112	
2011203	Station 148 Power Meter Install	QUE	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200305	9	3	12	I
2032721	Stn 102C - Isolate Air Start System	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200305	2	8	11	I
2032741	Stn 88C - Isolate Air Start System	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200305	2	8	10	I
2032742	Stn 75C - Disable Air Start System	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200305	2	5	7	I
2035001	Stn5&25B&C Air Comp/APU Vent.Upgd.	SASk	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200305	0	48	48	
2035003	Stn30/34B&C Air Comp/APU Vent.Upgd.	MAN	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200305	0	38	38	
2038625	Stn.75 Replace Heating Equip.	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200305	0	7	7	I
2038627	Stn.77 Replace Heating Equip.	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200305	0	31	31	
2039294	Stn.58 Upgd./Retire Comp.Air Sys	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200305	0	22	22	I
2039442	Stn.107B Repl. Failed Batteries	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200305	0	12	12	
2041022	Stn.144 Station Battery Repl.	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200305	0	11	11	
	FDPS Total 200305									**98**	**159**	**257**	
2019622	CIAC: Suffield 2 M/S Tie-in	SASk	M	8	3.82	Capacity	2001 XG-100 Appl.	2001 XG-100	200306	88	5	93	
2030741	Stn.80B VFD Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200306	12	2	14	I
2034602	Stn 5D Air Compressor Ventilation	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200306	0	24	24	I
2038629	Stn.84 Replace Heating Equip.	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200306	0	21	21	
2039463	Stn.25 APU feeder Re-routing	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200306	0	100	100	I
2039603	Inst.Launch/Recr'Stn.2&9 Ln100-2	SASk	P	1	2.82	Safety	2003 S.58-02	XG-T001-04-2003	200306	0	1,497	1,497	I
2040522	Stn 21A - 2003 Deactivation related upgrades	SASk	C	8	3.99	Functionality	2001 S.44 OPRs Deactivation	MO-09-2002	200306	0	152	152	I
2041665	MLV 62-2 + 16km SCC Cut Out	ONT	P	1	2.82	Safety	Emergency Repair Appl.	Emergency Repair	200306	0	292	292	I
2043522	Post Const.Recl.- MLV 126-127	ONT	P	1	2.82	Safety	1998 S.58-01	XG-T1-52-97	200306	0	3	3	I
	FDPS Total 200306									**100**	**2,098**	**2,198**	
2018542	C/S Fitting Replacts; Northern ONT	ONT	C	8	3.99	Safety	2001 XG-100 Appl.	2001 XG-100	200307	262	309	571	I
2029401	2002 CIU Program: Cypress Hills, Sk	SASk	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200307	181	42	223	I
2029402	2002 CIU Program: Central Cnd., Sk.	SASk	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200307	323	107	430	I
2029403	2002 CIU Program: Central Cnd., Mb.	MAN	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200307	181	97	278	I
2029404	2002 CIU Program: Central Cnd., Ont	ONT	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200307	181	26	207	I
2029407	2002 CIU Program: Toronto, PQ.	QUE	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200307	3	3	6	
2030583	C/S 2F Engine Cooling fan	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200307	10	1	11	
2034504	Advisory System Enhancement:TCPL	AB	O	8	5.7	Functionality	2002 S.58-10	XG-T001-53-2002	200307	56	85	141	I
2037745	119 Bracing for Valve Operators	ONT	C	8	3.99	Safety	2002 XG-100 Appl.	2002 XG-100	200307	2	4	7	I
2039283	Stn.45 Switch Gear Building	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200307	0	43	43	I
2039426	Stn.77B Replace Battery	ONT	C	8	3.99	Safety	2001 S.58-03	XG-T001-17-2001	200307	0	33	33	I
2039432	Stn.110C Repl.125VDC Batteries	ONT	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200307	0	16	16	I
2039461	Stn.21 BMCC Replacement	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200307	0	75	75	I
2039921	Stn.34B Plant MCC Repl.	MAN	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200307	0	279	279	I
2039966	Stn.17B Plant MCC Repl.	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200307	0	78	78	I
2040561	Stn 30A - 2003 Deactivation related upgrades	MAN	C	8	3.99	Functionality	2001 S.44 OPRs Deactivation	MO-09-2002	200307	0	163	163	I
2040565	25A Deactivation related upgrades	SASk	C	8	3.99	Functionality	2003 OPRs S.44	MO-01-2003	200307	0	178	178	I
2041225	Stn.86 Unit Controls Upgrade	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200307	0	127	127	I

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2042141	MLV 92-2+ 13.5km SCC Cut Out	ONT	P	1	2.82	Safety	Emergency Repair Appl.	Emergency Repair	200307	0	265	265	I
	FDPS Total 200307									**1,199**	**1,935**	**3,135**	
2041042	C/S 95 and 99 MLV Operator Repl.	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200308	0	48	48	I
2041143	Stn.5D 125vdc Battery Replace	SASk	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200308	0	17	17	I
2043045	Replace battery at 99B	ONT	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200308	0	16	16	I
2043602	Stn 123C Plant 125V Battery Repl	ONT	C	8	3.99	Economic	2001 S.58-03	XG-T001-17-2001	200308	0	21	21	I
	FDPS Total 200308									**0**	**102**	**102**	
2018502	Upgrade Fuel Control: Stn. 1301B	ONT	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200309	54	135	189	I
2021141	CIAC: Burstall PTI- Petrocan bypass	SASk	P	1	2.82	Capacity	2001 XG-100 Appl.	2001 XG-100	200309	0	185	185	I
2024141	Stn.80 - Install Power Meter	ONT	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200309	19	13	32	I
2034223	C/S 5 & 9 Units B&C New Louvers	SASk	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200309	0	111	111	I
2035462	Stn 130 - A1,2,3 Unit Valve Wiring	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200309	0	42	42	I
2036647	2F&G Air Compressor Upgrade	SASk	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200309	21	47	69	I
2036704	MLV75 Big Trout Creek Pipe Repl	ONT	P	1	2.82	Environmental	2003 S.58-07	XG-T001-19-2003	200309	58	872	929	I
2039281	Stn.49 Upgrade Fence Grounding	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	22	22	I
2039282	Stn.52 Upgrade Fence Grounding	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	13	13	I
2039284	Stn.17D Upgrade Enclosure Ventn	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	23	23	I
2039286	Stn.30D Upgrade Enclosure Ventn	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	20	20	I
2039417	116 'C' RTD Conduit Seal Upgrade	ONT	C	8	3.99	Environmental	2003 XG-100 Appl.	2003 XG-100	200309	0	24	24	I
2039428	Stn.86B Repl.Air Int.Filter Ctrl	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200309	0	14	14	I
2039825	Stn.2 APU/Air Comp. Repl.	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	699	699	I
2039962	Stn.30 MCC Replacement	MAN	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200309	0	140	140	I
2040562	Stn 34A - 2003 Deactivation related upgrades	MAN	C	8	3.99	Functionality	2001 S.44 OPRs Deactivation	MO-09-2002	200309	0	231	231	I
2040566	68A Deactivation related upgrades	ONT	C	8	3.99	Functionality	2003 OPRs S.44	MO-01-2003	200309	0	181	181	I
2041028	Stn.123 Railing Along Elect. Trench	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200309	0	17	17	I
2041029	Stn.1703 Electric Gate Installation	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200309	0	48	48	I
2041046	C/S 17 MLV Operator Replacement	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	48	48	
2041243	Stn.9 Sys2 24vdc Battery Replacement	SASk	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200309	0	5	5	
2044981	102B Plant Battery Replacement	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200309	0	16	16	I
	FDPS Total 200309									**152**	**2,905**	**3,058**	
2021282	2H/J PGT25+ Lube Oil Skid Vibration	SASk	C	8	3.99	Economic	2001 XG-100 Appl.	2001 XG-100	200310	26	2	28	I
2024961	Stn 80 Inst Power Line Protection	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200310	0	21	21	I
2029405	2002 CIU Program: N.Ontario	ONT	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200310	330	139	469	I
2029406	2002 GIU Program: Toronto, Ont.	ONT	C	8	3.99	Environmental	2002 S.58-06	XG-T001-36-2002	200310	128	47	175	I
2031283	Inst Launcher MFL Inspec. 804-806-1	QUE	P	1	2.82	Safety	2002 S.58-03	XG-T001-26-2002	200310	238	442	680	I
2031506	Stn 107 - Replace Operators	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200310	0	31	31	I
2035304	Stn.130: Inst. 2 MLV Limit Switches	ONT	C	8	3.99	Economic	2002 XG-100 Appl.	2002 XG-100	200310	0	31	31	
2039298	Stn 45B VFD Replacement	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200310	0	18	18	I
2039402	95'C' Install Heater in Comp Bldg	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200310	0	6	6	I
2039405	92-Improve drainage sump pump syst.	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200310	0	21	21	I
2039430	Stn.116 Repl. Bat's/Inv./Chrgrs.	ONT	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200310	0	15	15	I
2040259	RT56/62 PT Collector Manway:MB	MAN	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200310	0	56	56	I
2041032	Stn130A Plant Gas Detection Upgrade	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200310	0	19	19	I
2041033	Stn.130A Plant Fire Detection Upgrd	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200310	0	53	53	I
2041044	C/S 45 3MLV Operator Replacement	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200310	0	80	80	I

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2041061	Stn 49 Replace Water Main	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200310	0	30	30	I
2041261	Stn.5D 24vdc Battery Replacement	SASk	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200310	0	6	6	I
2041263	Stn.2 Sys1 24vdc Battery Replacement	SASk	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200310	0	5	5	I
2041265	Stn.2F 24vdc Battery Replsacement	SASk	C	8	3.99	Functionality	2001 S.58-03	XG-T001-17-2001	200310	0	5	5	I
2041883	2003 Hand Pump Repl. TCPL Ont.	ONT	P	1	2.82	Functionality	2003 XG-100 Appl.	2003 XG-100	200310	0	27	27	I
2041885	2003 Hand Pump Repl. TCPL Mb.	MAN	P	1	2.82	Functionality	2003 XG-100 Appl.	2003 XG-100	200310	0	10	10	I
2042523	102A-Repl.Scrubber Blowdown Tank	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200310	0	35	35	I
2042846	1217 Control Room HVAC Repl.	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200310	0	40	40	I
2044563	88B Cor. bent 2" Piping Config.	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200310	0	23	23	I
	FDPS Total 200310									**722**	**1,163**	**1,885**	
2011202	Station 112 Power Meter Install	ONT	C	8	3.99	Functionality	2001 XG-100 Appl.	2001 XG-100	200311	10	3	13	I
2039287	Stn.21D Enclosure Vent Upgrade	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	17	17	I
2039288	Stn.25D Enclosure Vent Upgrade	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	16	16	I
2039289	Stn.34D Enclosure Vent Upgrade	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	16	16	I
2039290	Stn.41E Enclosure Vent Upgrade	MAN	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	12	12	I
2039401	77, 99 and107 Aftercooler Platforms	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	60	60	I
2039403	102 'A' Lube Oil Upgrade	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	15	15	
2039406	Stn 80C Improve Ventilation	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	16	16	I
2039409	110-Upgrade station drainage	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200311	0	10	10	I
2039422	Stn.95 'C' Plant Frost Heave	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	51	51	I
2039424	Stn.86 Inst. Domestic Water Syst.	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	21	21	I
2039434	86-Repair leaking 86 203D X-Over	ONT	C	8	3.99	Environmental	2003 XG-100 Appl.	2003 XG-100	200311	0	53	53	I
2039440	92B/99B/110B-Hydr'c Regulators	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	68	68	I
2039444	Stn.88 Distorted Piping	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	26	26	I
2040261	Stn 55B Noise Mgmt./Helmholtz Array	ONT	C	8	3.99	Environmental	2003 XG-100 Appl.	2003 XG-100	200311	0	354	354	I
2041026	148 C&D Energen Encl.- False Floor	QUE	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	19	19	I
2041083	Station 116 Fall Hazard Protection	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	44	44	I
2041881	Stn 80C PGT 25+ HSPT Failure	ONT	M	8	3.82	Economic	2003 XG-100 Appl.	2003 XG-100	200311	0	53	53	I
2042549	58C1 LM2500+ 642-112 Blades	ONT	C	8	3.99	Environmental	2003 XG-100 Appl.	2003 XG-100	200311	0	82	82	I
2042742	77B1 Mars Combustion Liner Replacement	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200311	0	113	113	I
2043784	Stn.5E RB211 Fuel Cntl Upgd.	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	7	7	I
2043843	Stn 5 Plnt D Replace Failed HVAC	SASk	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200311	0	48	48	I
2044345	116-Utility/Cold Storage Smoke Det.	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200311	0	9	9	I
2045763	Generators and Inst. MLV 67	ONT	P	1	2.82	Functionality	2003 S.58-21	XG-T001-46-2003	200311	0	102	102	I
	FDPS Total 200311									**10**	**1,216**	**1,226**	
2031644	1211A/1217A RTD Module Replacement	ONT	C	8	3.99	Functionality	2002 XG-100 Appl.	2002 XG-100	200312	5	9	14	I
2039408	75-Install evacuation system	ONT	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	17	17	
2040008	1301B PGT-10 Encl. Ventilation Upgd	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	56	56	I
2040258	RT56/62 PT Collector Manway:SK	SASk	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	33	33	I
2040260	RT56/62 PT Collector Manway:ONT.	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	89	89	I
2040273	C/S CP Remedial Central Man	MAN	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	25	25	I
2040274	C/S CP Remedial Central Ont	ONT	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	176	176	I
2040563	45A Deactivation realted upgrades	MAN	C	8	3.99	Functionality	2001 S.44 OPRs Deactivation	MO-09-2002	200312	0	501	501	I
2040747	CEHM - TCPL	AB	O	8	5.7	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	351	351	I
2040972	Stn 13 Cooler Screen Modifications	SASk	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	25	25	I
2041063	Fall Protection Program - Sask.	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	40	40	I

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2041064	Fall Protection Program - Manitoba	MAN	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	71	71	I
2041223	Stn.45 Unit Controls Upgrade	MAN	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	143	143	I
2041381	Stn147 Utility Transformer Replacement	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	200	200	I
2041681	Stn.5 Building Fall Protection	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	95	95	I
2041682	Stn.9 Building Fall Protection	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	74	74	I
2041782	2003 CIU - Stn 25	SASk	C	8	3.99	Environmental	2003 S.58-09	XG-T001-22-2003	200312	0	172	172	I
2041783	2003 CIU - Stn 62	ONT	C	8	3.99	Environmental	2003 S.58-09	XG-T001-22-2003	200312	0	14	14	I
2041784	2003 CIU - Stn 75	ONT	C	8	3.99	Environmental	2003 S.58-09	XG-T001-22-2003	200312	0	7	7	I
2041787	2003 CIU - Stn 148	QUE	C	8	3.99	Environmental	2003 S.58-09	XG-T001-22-2003	200312	0	8	8	I
2043043	5C Fire Foam pump & Pipe upgrade	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	13	13	I
2043588	Stn.13 - Fall Protection	SASk	C	8	3.99	Safety	2003 XG-100 Appl.	2003 XG-100	200312	0	59	59	I
2044331	60B VFD Replacement	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	18	18	I
2044333	62B VFD Replacement	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	19	19	I
2044342	69B VFD Replacement	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	45	45	I
2044625	Stn 43B VFD MCC Replacement	MAN	C	8	3.99	Economic	2003 XG-100 Appl.	2003 XG-100	200312	0	19	19	I
2046101	C/S 105 Replace Fuel Gas Heater	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	34	34	I
2047222	PGT25+ HSPT Upgrade Station 107C1	ONT	C	8	3.99	Functionality	2003 XG-100 Appl.	2003 XG-100	200312	0	222	222	I
	FDPS Total 200312									**5**	**2,535**	**2,540**	
	TOTAL TRANSMISSION									**13,382**	**17,228**	**30,610**	

I Updated to reflect 2003 actual costs.

SUMMARY OF TRANSMISSION PLANT ADDITIONS
TEST YEAR ENDING DECEMBER 31, 2004
($000)

Category	January	February	March	April	May	June	July	August	September	October	November	December	TOTAL	
MAINS	3,436	3,513	3,739	91	1,320	549	684	2,201	2,022	1,937	3,385	3,931	26,809	I
COMPRESSION	1,475	1,847	2,075	1,560	1,173	1,411	1,371	1,417	1,485	1,429	1,495	1,499	18,237	I
METERING	8	13	17	22	25	22	20	20	25	30	27	22	250	
COMMUNICATIONS	28	28	38	48	54	51	44	42	49	49	59	54	544	
TOTAL	4,947	5,401	5,869	1,721	2,572	2,033	2,119	3,679	3,581	3,445	4,967	5,506	45,840	I

I Updated to reflect the impact of 2003 actuals on opening balances for 2004.

2004 Tolls Variance Explanations: NEB Certificate / Latest Estimate

Project Number	Description	Board Order Certificate Cost	Latest Estimated Construction Cost	Cost Variance	Variance Explanation	
1002376	T00625 - Replace Pipeline MLV: 106	$5,325,000	$4,611,375	-$713,625	Contractors lump sum prices for pipe replacements were lower than anticipated and material costs were reduced by utilizing items from inventory.	I
2002242	2000 CIU Program Design-Stn.21	$458,000	$782,401	$324,401	The application for the 2000 CIU Program was based on an average cost per site. The actual total cost of the program was less than budgeted, however this site required additional reclamation work.	I
2002258	2000 CIU Program Design-Stn.209	$458,000	$161,335	-$296,665	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation.	I
2002259	2000 CIU Program Design-Stn.148	$458,000	$333,995	-$124,005	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation.	I
2002460	2000 CIU Prog.Design-Stn.95	$458,000	$249,196	-$208,804	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation.	I
2029144	2002 Corr Rem Prog:SK Cypress Hills	$1,356,727	$1,212,972	-$143,755	Some sites were cancelled from the original application after additional diagnostic testing was completed.	I
2029147	2002 Corr Rem Prog: ON Central	$2,074,913	$2,797,823	$722,910	The application for corrosion remedial projects was based on an average cost per site. Sites for this project had more rock than the average site, increasing construction costs. Unexpected project delays forced construction to occur during winter months, increasing construction costs.	I
2029148	2002 Corr Rem Prog: ON Northern Ont	$674,971	$1,114,937	$439,966	The application for corrosion remedial projects was based on an average cost per site. Sites for this project had more rock than the average site, increasing construction costs. Unexpected project delays forced construction to occur during winter months, increasing construction costs.	I
2029149	2002 Corr Rem Prog: ON Toronto	$803,549	$2,136,865	$1,333,316	The application for corrosion remedial projects was based on an average cost per site. Sites for this project had more rock than average and unexpected project delays forced construction to occur during winter months, resulting in increased costs. Congested site conditions and electrical interference at specific sites increased costs for design, construction and materials.	
2029401	2002 CIU Program: Cypress Hills, Sk	$343,000	$223,760	-$119,240	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation.	I

I Updated to reflect 2003 actual costs and latest estimates.

2004 Tolls Variance Explanations: NEB Certificate / Latest Estimate

Project Number	Description	Board Order Certificate Cost	Latest Estimated Construction Cost	Cost Variance	Variance Explanation
2029402	2002 CIU Program: Central Cnd., Sk.	$301,500	$430,281	$128,781	The application for the 2002 CIU Program was based on an average cost per site. The actual total cost of the program was less than budgeted, however sites on this project required additional reclamation work. I
2029403	2002 CIU Program: Central Cnd., Mb.	$388,000	$278,655	-$109,345	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation. I
2029404	2002 CIU Program: Central Cnd., Ont	$314,800	$208,602	-$106,198	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation. I
2029406	2002 GIU Program: Toronto, Ont.	$760,500	$174,507	-$585,993	Bundling work decreased construction costs and completion of further site investigation resulted in less reclamation. I
2029425	2002 CSD Program: N.Ontario	$322,000	$188,704	-$133,296	Actual number of samples was less than originally anticipated.
2036704	MLV75 Big Trout Creek Pipe Repl:CO	$325,000	$929,467	$604,467	Construction costs were higher than anticipated due to site conditions and unexpected equipment malfunctions.
2038681	Stn.9&17 Launcher/Reciever:CO	$700,000	$1,468,943	$768,943	Wet weather and unfavourable site conditions caused construction delays and increased costs. I
2040266	2003 Cypress Sask CP Remediation	$1,037,400	$710,835	-$326,565	The application for corrosion remedial projects was based on an average cost per site. Sites for this project had required less work compared to the average site based on specific site conditions, lowering construction costs. I
2040268	2003 Central Manitoba CP Remed'n	$871,100	$713,306	-$157,794	The application for corrosion remedial projects was based on an average cost per site. Sites for this project had required less work compared to the average site based on specific site conditions, lowering construction costs. I
2040270	2003 Northern Ontario CP Remediat'n	$1,267,700	$710,298	-$557,402	The application for corrosion remedial projects was based on an average cost per site. Sites for this project had required less work compared to the average site based on specific site conditions, lowering construction costs. I

I Updated to reflect 2003 actual costs and latest estimates.

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Project No		Latest Estimated FDPS Date	Original Estimated FDPS Date (previous test year)	FDPS Variance	Explanation
2029401	2002 CIU Program: Cypress Hills, Sk	200307	200212	7	see note 1
2029402	2002 CIU Program: Central Cnd., Sk.	200307	200212	7	see note 1
2029403	2002 CIU Program: Central Cnd., Mb.	200307	200212	7	see note 1
2029404	2002 CIU Program: Central Cnd., Ont	200307	200212	7	see note 1
2029405	2002 CIU Program: N.Ontario	200310	200212	10	see note 1
2029406	2002 GIU Program: Toronto, Ont.	200310	200212	10	see note 1
2031283	Inst Launcher MFL Inspec. 804-806-1	200310 l	200207	15 l	see note 1

Note:

1. Project schedule delayed due to manpower and/or material availability.

l Updated to reflect 2003 actual.

TRANSMISSION PLANT MAJOR RETIREMENTS
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($000)

Project Number	Description	Justification Code	FRPS	Book Costs	Removal Costs	Salvage Proceeds	Net Charges to Accumulated Depreciation	
Section 1 - MAINS								
2034812	2002 Valve Oper Replacement	Economic	200212	339	6	0	345	I
2036705	MLV75 Big Trout Creek Pipe Repl	Environmental	200311	435	0	0	435	I
TOTAL	**SECTION 1 - MAINS**			**774**	**6**	**0**	**779**	
Section 2 - COMPRESSION								
1001372	R06282 - Retire Station 105C Plant	Capacity	199807	0	332	0	332	I
1002334	R06511 - Retire Unit Station 2A 1-6	Capacity	199909	(1)	150	0	149	I
1002300	R06717 - Replace Generator Station 86	Economic	200009	(388)	0	0	(388)	I
2023482	Stn130 Units A1,A2,A3 Cntrl. U/G	Safety	200201	118	0	0	118	I
1002403	R06281 - Retire Station 5A Plant	Capacity	200201	0	460	0	460	I
1002405	R06300 - Retire Station 9A Plant	Capacity	200201	0	545	(4)	541	I
2009766	Ignace Unit 58A1-5 Retirements	Capacity	200201	0	200	0	200	I
2009770	Barry Unit 127A Retirement	Capacity	200201	(1)	224	0	222	I
2011784	Geraldton Unit 80A1-5 Retirements	Capacity	200201	1	203	0	203	I
2039022	Stn 110C RB211 IP Turbine Casing	Economic	200204	170	0	0	170	I
2039024	1301B1 PGT 10 Liner/Trans. Pce	Economic	200204	402	0	0	402	I
2039026	1703B1 PGT 10 Comb. Liner U/G	Economic	200204	412	0	0	412	I
2039088	Stn.1206A1 PGT 16 PT Casing Upgd	Economic	200204	396	0	0	396	I
2039102	Stn. 88B1 PGT 16 PT Casing Upgd	Economic	200204	214	0	0	214	I
2034721	Stn 13B Cooler Retirement	Capacity	200208	0	415	(1,589)	(1,174)	I
2034961	Unit 13B Phase I Deactivation	Capacity	200208	0	172	0	172	I
1002404	R06297 - Retire Station 105B Plant	Capacity	200211	472	393	0	864	I
2033523	BCO: Stn 95C: Replace VFD	Economic	200302	309	0	0	309	I
2036642	Stn.127B RB211 #1780453 Repair	Economic	200304	1,379	0	0	1,379	I
2036644	Stn.127B RB211 #1780425 Repair	Economic	200304	452	0	0	452	I
2037205	5D DJ-270 Rotor Refurb.	Functionality	200304	289	0	0	289	I
2037442	127B RT62 Rotor & Stg 1/2 Vanes	Economic	200304	699	0	0	699	I
2042081	Retire RCC Generator Set	Economic	200305	183	(8)	0	175	I
TOTAL	**SECTION 2 - COMPRESSION**			**5,107**	**3,085**	**(1,593)**	**6,599**	I
Section 3 - METERING								
2034964	2001 Daniel 2500 Flow Comp U/G:MB	Economic	200206	453	0	0	453	I
2034965	2001 Daniel 2500 Flow Comp U/G:ON	Economic	200206	261	0	0	261	I
TOTAL	**SECTION 3 - METERING**			**715**	**0**	**0**	**715**	I
TOTAL	**OTHER RETIREMENTS**			**1,874**	**432**	**0**	**2,307**	I
TOTAL	**TRANSMISSION PLANT MAJOR RETIREMENTS**			**8,470**	**3,524**	**(1,593)**	**10,399**	I

I Updated to reflect 2003 actual costs.

2004 Mainline Tolls and Tariff Application
February 2004 Update

PART X REQUIREMENTS
SS.26-27

PRO FORMA BALANCE SHEET
CANADIAN MAINLINE
AS AT DECEMBER 31
($ Million)

LINE NO.	PARTICULARS	NEB ACCOUNT	Base Year 2002	Actual Year 2003	Test Year 2004	
	(a)	(b)	(c)	(d)	(e)	
1	ASSETS					
2	Current Assets					
3	Accounts receivable	140-147	190	193	187	l
4	Inventories	150-152	54	48	47	
5	Other	160	2	2	2	
6			246	243	236	l
7	Long-Term Investments					
8	Plant, Property and Equipment	100-115,153	8,649	8,277	7,925	l
9	Other Assets	170-179	(13)	(45)	15	l
10			8,882	8,475	8,176	l
11						
12	LIABILITIES AND SHAREHOLDERS' EQUITY					
13	Current Liabilities					
14	Accounts payable	251	2	39	385	l
15	Accrued interest	257	134	125	113	l
16	Long-term debt due within one year	258	94	146	180	
17			230	310	678	l
18	Long-Term Debt	220	4,853	4,707	4,278	
19	Junior Subordinated Debentures	220	238	22	-	
20			5,321	5,039	4,956	l
21	Shareholders' Equity	200-212	3,561	3,436	3,220	l
22			8,882	8,475	8,176	l

l Updated to reflect 2003 actual amounts and 2004 revised capitalization.

PRO FORMA INCOME STATEMENT
CANADIAN MAINLINE
FOR THE YEAR ENDED DECEMBER 31
($ Million)

LINE NO.	PARTICULARS	NEB ACCOUNT	Base Year 2002	Actual Year 2003	Test Year 2004	
	(a)	(b)	(c)	(d)	(e)	
1	Revenues	300	2,178	2,247	2,188	l
2						
3	Other costs and expenses	301/302/305	804	840	815	l
4	Depreciation	303-304	362	420	415	l
5			1,166	1,260	1,230	l
6	Operating Income		1,012	987	958	l
7	Financial charges	320-321	478	456	450	l
8	Allowance for funds used during construction	324	(1)	(1)	-	
9	Interest and other income	319	(1)	(1)	(75)	
10			476	454	375	l
11	Income before Income Taxes		536	533	583	l
12	Income Taxes	306	194	211	219	l
13	Net Income		342	322	364	l
14	Preferred Securities Charges	320	35	35	18	
15	Net Income Applicable to Common Shares		307	287	346	l

l Updated to reflect 2003 actual amounts and 2004 revenue requirement updates.