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March 21, 2005

Alberta Energy and Utilities Board
640-5th Avenue S.W.
Calgary, Alberta
T2P 3G4

By Electronic Filing

Attention: **Mr. Robert Heggie,**
Executive Manager, Utilities Branch

Dear Sir:

Re: NOVA Gas Transmission Ltd. (NGTL)
2005-2007 Revenue Requirement Settlement Application

Enclosed for filing with the Board is NGTL's 2005-2007 Revenue Requirement Settlement Application. Pursuant to the Board's letter of March 18, 2005, NGTL understands that the withdrawal of its 2005 General Rate Application Phase 1 is effective by virtue of this filing.

NGTL will notify its customers, members of its Tolls, Tariff, Facilities and Procedures Committee and the participants in the settlement negotiations of the filing of this Application. Electronic copies of the Application will be available on NGTL's website at:
http://www.transcanada.com/Alberta/regulatory_info/active_rates_services_filings.htm

All notices and communications related to this matter should be directed to Klaus Exner by e-mail at klaus_exner@transcanada.com and to alberta_system@transcanada.com, or by phone at 920-5978 and to Patrick Keys by e-mail at patrick_keys@transcanada.com or by phone at 920-6237.

Yours truly,

NOVA Gas Transmission Ltd.
a wholly owned subsidiary of TransCanada PipeLines Limited

Céline Bélanger

Céline Bélanger
Vice President, Regulatory Services

Enclosures

cc: Tolls, Tariff, Facilities and Procedures Committee
Alberta System Shippers
Participants in Settlement Negotiations

NOVA Gas Transmission Ltd.

2005-2007 Revenue Requirement Settlement Application

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ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-7, as amended, and the Regulations under it;

IN THE MATTER OF the *Gas Utilities Act*, R.S.A. 2000, c. G-5, as amended, and the Regulations under it;

IN THE MATTER OF the *Public Utilities Board Act*, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and

IN THE MATTER OF an Application by NOVA Gas Transmission Ltd. to the Alberta Energy and Utilities Board for an Order approving the NGTL 2005-2007 Revenue Requirement Settlement.

2005-2007 REVENUE REQUIREMENT SETTLEMENT APPLICATION

NOVA Gas Transmission Ltd. (NGTL) applies to the Alberta Energy and Utilities Board (Board) under Section 45 of the *Gas Utilities Act* and the provisions of Informational Letter IL 98-04 Revised, being the Revised Negotiated Settlement Guidelines Tolls, Tariffs, and Terms and Conditions of Service, for an Order:

(a) approving the NGTL 2005-2007 Revenue Requirement Settlement (Settlement), provided as Appendix A of this Application, in its entirety; and

(b) granting such further and other relief as NGTL may request or the Board may determine is appropriate.

In support of its Application, NGTL provides and relies on the information in the Application, including the attached evidence, schedules and explanatories, and any additional information that NGTL may file, as directed or permitted by the Board.

Respectfully submitted.

March 21, 2005
Calgary, Alberta

NOVA GAS TRANSMISSION LTD.
A wholly owned subsidiary of
TransCanada PipeLines Limited

Per: Céline Bélanger

Céline Bélanger
Vice President, Regulatory Services

All notices and communications relating to this Application should be directed to:

NOVA Gas Transmission Ltd.
450 – 1st Street S.W.
Calgary, Alberta T2P 5H1

Attention: Klaus Exner
Regulatory Services

Telephone: (403) 920-5978
Fax: (403) 920-2347
E-mail: klaus_exner@transcanada.com
E-mail: alberta_system@transcanada.com

and to: NOVA Gas Transmission Ltd.
450 – 1st Street S.W.
Calgary, Alberta T2P 5H1

Attention: Patrick M. Keys
Associate General Counsel - Regulatory

Telephone: (403) 920-6237
Fax: (403) 920-2420
E-mail: patrick_keys@transcanada.com

1.2 INTRODUCTION

Q1. What is the purpose of this Application?

A1. NGTL seeks Board approval of the 2005-2007 Revenue Requirement Settlement (Settlement). The Settlement establishes the mechanisms through which the 2005-2007 Alberta System Revenue Requirements will be determined, based on a combination of fixed and flow-through cost elements. A copy of the Settlement is provided in Appendix A.

The Settlement is the product of negotiations between NGTL and interested Alberta System stakeholders. It represents an acceptable balance of interests amongst the parties, and results from compromises in the diverse interests and positions of the parties. Consequently, the components of this Settlement are inextricably linked and are presented to the Board for approval as a package.

NGTL explains in this Application the basis of the Settlement and how it meets the interests of the parties and the general public interest.

2.0 NEGOTIATED SETTLEMENT PROCESS

Q1. Describe the events leading up to this Application.

A1. Following a period of years in which the Alberta System's annual revenue requirement was determined through negotiated settlements, the Alberta System revenue requirement for 2004 was determined through a General Rate Application (GRA). NGTL filed its 2004 GRA in fulfillment of its commitment in the 2003 Alberta System Revenue Requirement Settlement (ASRRS) and in compliance with the Board's subsequent direction in Decision 2003-051[1] to file a comprehensive 2004 GRA. Following a hearing on the 2004 GRA, in which interested parties had an opportunity to examine all components of NGTL's 2004 revenue requirement, the Board issued Decision 2004-069[2] establishing the basis for the 2004 revenue requirement.

On August 18, 2004, NGTL applied to the Board for approval to initiate negotiations on a revenue requirement settlement for a period of up to five years, commencing January 1, 2005. In Decision 2004-077,[3] issued September 10, 2004, the Board approved NGTL's request, with the condition that the settlement period not exceed three years commencing January 1, 2005.

On November 8, 2004, by letter, NGTL invited members of the Tolls, Tariff, Facilities and Procedures Committee (TTFP), parties to NGTL's 2004 GRA Phases 1 and 2 and all Alberta System shippers to participate in the settlement negotiations. The letter constituted notice of a meeting that was held on November 17, 2004, at which time interested parties were asked to enter into a confidentiality agreement with NGTL so that further discussions could be conducted on a confidential and

[1] Alberta Energy and Utilities Board, Decision 2003-051, NOVA Gas Transmission Ltd., 2003 Revenue Requirement and Tariff Settlement Applications (June 24, 2003), page 27.
[2] Alberta Energy and Utilities Board, Decision 2004-069, NOVA Gas Transmission Ltd., 2004 General Rate Application Phase 1 (August 24, 2004), (EUB Decision 2004-069).
[3] Alberta Energy and Utilities Board, Decision 2004-077, NOVA Gas Transmission Ltd., Request for Approval to Commence Negotiations (September 10, 2004).

without prejudice basis. A copy of the letter is provided as Appendix B.

At a subsequent meeting on December 10, 2004, NGTL provided a detailed settlement proposal to stakeholders. Following this meeting, NGTL filed its 2005 GRA Phase 1 with the Board on December 15, 2004. The 2005 GRA Phase 1 provided interested parties with additional background information. NGTL stated in the transmittal letter that it was continuing settlement negotiations and that it would amend or replace the 2005 GRA Phase 1 if a settlement was achieved.

Ongoing negotiations meetings and discussions were held throughout January and February. On January 25, 2005, the Board issued a Notice of Hearing for the 2005 GRA Phase 1, including a schedule for adjudication. On February 10, 2005, NGTL requested that the Board revise the 2005 GRA Phase 1 schedule to allow parties to complete the settlement discussions. The Board approved this request on February 11, 2005 and issued a revised schedule.

On February 24, 2005, NGTL notified the Board that it had reached an agreement in principle on a negotiated settlement and requested that the Board suspend the GRA process while it finalized a settlement agreement with stakeholders. The Board approved NGTL's request on February 25, 2005 and directed NGTL to provide an update on the status of the settlement agreement by March 15, 2005.

On March 15, 2005, NGTL advised the Board that the Settlement had been executed. NGTL also stated that it intended to file this Settlement Application by the end of March and, as a consequence, NGTL sought the Board's approval to withdraw the 2005 GRA Phase 1. On March 18, 2005, The Board approved the withdrawal of the 2005 GRA Phase 1, on the basis that the withdrawal be effective concurrent with the filing of this Application.

Q2. Did NGTL follow the general requirements of the Board's Negotiated Settlement Guidelines under IL 98-04 Revised in reaching the 2005-2007 Settlement?

A2. Yes. NGTL believes that the settlement process was open and fair. It provided an appropriate forum for all interested parties to participate meaningfully in discussions on a confidential and without prejudice basis. NGTL also provided appropriate notice of meetings and made available sufficient information to facilitate understanding and review of the issues being negotiated. Additionally, an EUB staff member served as an observer at various negotiations meetings.

Q3. Which parties participated in the settlement negotiations?

A3. Lists of parties that attended the November 17, 2004 meeting and that executed confidentiality agreements to participate in the negotiations process are included in Appendix C. The participants represent a broad cross-section of Alberta System stakeholders, including producers, marketers, intra-Alberta industrial and residential customers and ex-Alberta delivery LDC customers, either directly and/or through their representative associations.

Q4. Are there any issues related to the 2005-2007 Alberta System revenue requirements that were not resolved in negotiations?

A4. No. The parties resolved all components of the 2005-2007 revenue requirements.

Q5. Does the Settlement address any other issues?

A5. Yes. The Settlement does provide for parties to enter into industry-wide discussions during the term of the Settlement with respect to the terminal net negative salvage issue and for NGTL to consult with shippers, during the term of the Settlement, on the issue of its long term debt funding position.

Q6. Who are the signatories to the Settlement?

A6. The Settlement was signed by:

- Anadarko Canada Corporation;
- BP Canada Energy Company;
- Canadian Association of Petroleum Producers (CAPP);
- Cargill Power & Gas Markets;
- EnCana Corporation;
- Industrial Gas Consumers Association of Alberta (IGCAA);
- NOVA Gas Transmission Ltd.;
- Pacific Gas & Electric Company;
- Puget Sound Energy, Inc.;
- Small Explorers and Producers Association of Canada (SEPAC);
- Talisman Energy Inc,;
- Terasen Gas Inc.; and
- Utilities Consumer Advocate.

BP Canada Energy Company and CAPP also provided letters of comment on the Settlement, copies of which are provided in Appendix D.

Q7. Did all of the participants in the settlement discussions execute the Settlement?

A7. No. Certain participants in the settlement discussions chose not to sign the Settlement. Some of them decided to have their support represented through their respective industry associations rather than by signing the Settlement directly. The following participants have indicated to NGTL that they either support or do not oppose the Settlement:

- Alberta Urban Municipalities Association;
- ATCO Pipelines;
- Avista Energy Canada, Ltd;
- Burlington Resources Canada Partnership;
- Cascade Natural Gas Corporation;
- Consumers' Coalition of Alberta (CCA);
- Consumer Group;
- Coral Energy Canada Inc.;
- Nexen Inc.;
- Northwest Natural Gas Company; and
- Petro Canada Oil and Gas.

Certain of the above parties have provided letters of comment stating their position on the Settlement, copies of which are provided in Appendix D.

Q8. Is the Settlement opposed by any of the participants in the negotiations?

A8. No. NGTL understands that all of the participants either support or do not oppose the Settlement.

Q9. Does that conclude NGTL's evidence in this section?

A9. Yes.

3.0 TERMS OF THE 2005-2007 SETTLEMENT

3.1 Key Terms of the Settlement

Q1. What is the general structure of the Settlement?

A1. The Settlement encompasses all elements of the Alberta System revenue requirement, but does not extend to any rate design, accountability, services or competitive issues. The Settlement establishes methodologies for calculation of the 2005, 2006 and 2007 Alberta System revenue requirements, based on fixed and flow-through cost components and the use of deferral accounts for various revenues and costs.

For the Settlement to be binding on any party, it must be approved by the Board in its entirety. The Settlement results from and reflects compromises by the participants respecting their different interests and positions on the various components. Consequently, all components of the Settlement are inextricably linked and must be treated as a single package.

Q2. Which cost components are fixed under the Settlement?

A2. The Settlement defines fixed annual cost amounts for Operating Costs and Other Costs for 2005 to 2007. Operating Costs encompass all operating, maintenance and administration costs that NGTL will incur during the term of the Settlement that are not otherwise specified as Other Costs or flow-through costs. Other Costs are comprised of foreign exchange on interest payments, uninsured losses and amortization of severance costs incurred in previous years under the terms of the 2003 ASRRS.

The fixed cost components are “black box” amounts. The amounts do not represent any particular expense type, other than those specifically identified in the Settlement. Similarly, parties to the Settlement have not attributed any specific amount to any particular expense type within the negotiated “black box” amounts.

Any variances between actual results and the negotiated fixed cost amounts are the responsibility of NGTL. Specifically, NGTL is at risk for any expenses incurred above the fixed cost amounts and will receive the benefit of any cost savings achieved.

Q3. Which cost components are flow-through under the Settlement?

A3. Flow-through cost components consist of:

- return on equity;
- debt expenses;
- depreciation;
- property, income and large corporation taxes;
- transportation by others;
- regulatory hearing costs;
- pipeline integrity costs (expense);
- annual foreign exchange amortization amount;
- CO_2 management service costs (expense);
- audit adjustment; and
- deferral accounts.

The flow-through costs in this settlement are reasonable estimates of the actual costs that, as prudently incurred, will flow through to shippers. The mechanisms for the determination of some of the flow-through costs are detailed in the Settlement. For example, return on equity will be calculated using the formula for determining the annual generic rate of return on common equity established in Decision 2004-052[1] on deemed common equity of 35%.

Annual amounts for the flow-through costs will be based on NGTL's forecast of the reasonable expenses it will prudently incur to operate the Alberta System at existing service levels. NGTL will use deferral accounts to record and account for variances between forecast and actual flow-through costs.

3.2 Annual Revenue Requirements

Q4. What is the 2005 revenue requirement as determined under the provisions of the Settlement?

A4. The 2005 revenue requirement is $1,160 million. It includes the amounts identified in Appendix 1 to the Settlement, the audit adjustment and the 2004 deferral account balances. A schedule detailing the composition of the 2005 revenue requirement is provided in Appendix E.

Q5. How does the 2005 revenue requirement compare to the approved 2004 revenue requirement and the revenue requirement applied-for in the 2005 GRA Phase 1?

A5. NGTL provides a schedule in Appendix E that compares the 2005 revenue requirement to those approved for 2004 and previously applied-for in the 2005 GRA Phase 1. The 2005 revenue requirement is approximately $85 million lower than the approved 2004 revenue requirement and approximately $12 million lower than the revenue requirement in the 2005 GRA Phase 1.

Q6. What is the impact of the Settlement on 2005 rates, tolls and charges?

A6. Final 2005 rates, tolls and charges cannot be determined until both this Application and the 2005 GRA Phase 2 have been determined. NGTL presently intends to file its 2005 GRA Phase 2 by April 1, 2005 in accordance with the Board's direction in

[1] Alberta Energy and Utilities Board, Decision 2004-052, Generic Cost of Capital (July 2, 2004), page 32.

Decision 2004-097.[2] However, NGTL provides in Appendix G illustrative 2005 rates, tolls and charges calculated in accordance with the rate design approved by the Board in Decision 2004-097, forecast 2005 contract demand and throughput quantities, as outlined in Appendix F, and the 2005 revenue requirement provided in Appendix E.

Q7. What rates, tolls and charges for services is NGTL currently charging?

A7. NGTL is currently charging interim rates, tolls and charges for service on the Alberta System (2005 Interim Rates), which the Board approved in Order U2004-446.[3]

Q8. Will NGTL amend the 2005 Interim Rates to incorporate the revised 2005 revenue requirement pending the Board's determination of this Application and NGTL's 2005 GRA Phase 2?

A8. No. The rates, tolls and charges determined using the revenue requirement resulting from the Settlement would be only 3% lower than the 2005 Interim Rates. Therefore, NGTL intends to continue charging the existing 2005 Interim Rates until both this Application and the 2005 GRA Phase 2 have been determined.

Q9. Have the revenue requirements for 2006 and 2007 been determined?

A9. No. Revenue requirement amounts for 2006 and 2007 are provided in Appendix 1 of the Settlement for illustrative purposes. The fixed cost components shown in the Settlement will not change; however, the flow-through cost components shown will be updated when the 2006 and 2007 revenue requirements are finalized. The applicable deferral account balances will also be calculated at that time.

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[2] Alberta Energy and Utilities Board, Decision 2004-097, NOVA Gas Transmission Ltd., 2004 General Rate Application Phase 2 (October 26, 2004), page 19.

[3] Alberta Energy and Utilities Board, Order U2004-446, NOVA Gas Transmission Ltd., 2005 Interim Rates, Tolls and Charges (December 14, 2004).

Q10. How will the final revenue requirements for 2006 and 2007 be calculated?

A10. NGTL will calculate forecast 2006 and 2007 revenue requirements and provide this information to the parties to the Settlement by November 1, 2005 for the 2006 revenue requirement, and by November 1, 2006 for the 2007 revenue requirement.

By March 15 of each year, the forecast revenue requirement will be updated to reflect the actual results from the prior year. This information will be provided to the parties to the Settlement.

Q11. How will rates for 2006 and 2007 be calculated?

A11. For each year, NGTL will calculate interim rates, tolls and charges based on the forecast revenue requirement, a forecast of firm transportation contract demand quantity and throughput, and the approved rate design in place at the time. On or before December 1 of the prior year, the interim rates, tolls and charges will be provided to interested parties and filed with the Board for approval.

The final rates, tolls and charges for each year will be calculated and provided to interested parties and filed with the Board for approval on or before March 15 of each year. Such final rates shall enable NGTL to collect its annual revenue requirement, recognizing amounts collected under interim rates.

3.3 Deferral and Reserve Accounts

Q12. What deferral and reserve accounts will be used for 2005, 2006 and 2007?

A12. NGTL will use the following deferral accounts for 2005, 2006 and 2007:

- Revenue;
- CO_2 Management Service Costs; and
- Flow-through Costs.

The Revenue deferral account will continue to be used for the same purpose it was used for in 2004 and will consist of:

1. Variances in revenue resulting from actual Firm Transportation Contract Demand Revenue differing from the forecast of Firm Transportation Contract Demand revenue used in establishing the applicable year's rates. This includes all variances related to all Firm Transportation.

2. Variances in revenues resulting from actual Interruptible Transportation Services revenue differing from the forecast of Interruptible Transportation Services revenue used in establishing the applicable year's rates. This includes all variances from interruptible receipt and interruptible delivery revenues net of alternate access, as well as intra-Alberta delivery service, Facilities Connection Service, Pressure/Temperature Service and Other Services.

The CO_2 Management Service deferral account will continue to be utilized in the same manner it was used in 2004. It will capture the variances between forecast and actual revenues and forecast and actual costs attributable to the CO_2 Management Service in the applicable year. Any incentive earned by NGTL under the provisions of the CO_2 incentive mechanism will also be recorded in this account.

The Flow-through Costs deferral account will capture the variances between forecast and actual costs for all flow-through cost components of the revenue requirement, with the exception of costs related to the CO_2 Management Service. A breakdown of the deferral account balance by cost component will be provided in the annual rate calculation process.

The Regulatory Hearing Costs reserve account established in Decision 2004-069 will be continued for the term of the Settlement. As directed by the Board, NGTL will not carry a Regulatory Hearing Costs reserve account balance in excess of $5 million at any time.[4]

Q13. How will the deferral accounts work?

A13. NGTL will record the variances between the forecast revenue or cost and the actual amounts collected or incurred for each revenue or cost item in the appropriate deferral account on a monthly basis. Carrying charges or credits will be calculated, at the Bank of Canada's Bank Rate plus 1.5%, on the balance in each deferral account at the end of each month and recorded in the respective deferral account.

NGTL will include the balances of the deferral accounts in the calculation of the subsequent year's revenue requirement.

Q14. How will NGTL dispose of the 2004 deferral account balances?

A14. NGTL has calculated the 2004 deferral account balances based on the 2004 revenue requirement amounts approved by the Board in Decision 2004-102.[5] The balances, including applicable carrying charges or credits, are included in the 2005 revenue requirement as per the terms of the Settlement.

3.4 Conclusion

Q15. Why does NGTL believe that the Board should approve the Settlement?

A15. NGTL submits that the Settlement is reasonable and fair to the parties and in the general public interest. Specifically:

- Participants in the negotiations represented a broad cross-section of Alberta System stakeholders, including producers, marketers, intra-Alberta industrial and residential customers and ex-Alberta delivery LDC customers. The participants

[4] EUB Decision 2004-069, page 47.
[5] Alberta Energy and Utilities Board, Decision 2004-102, NOVA Gas Transmission Ltd., 2004 General Rate Application Phase 1 Compliance Filing (November 17, 2004).

are sophisticated parties who are knowledgeable about the operations of the Alberta System and include interveners who were active in Phase 1 of the 2004 GRA. Their aggregate support of the Settlement is a strong basis on which the Board can reasonably conclude that the Settlement is in the interests of the stakeholders specifically and the public generally.

- After an extended period of determining revenue requirements under negotiated settlements, the 2004 GRA provided all parties with the opportunity to review the components of NGTL's revenue requirement in detail and determine the appropriateness of the costs being incurred to provide transportation service on the Alberta System. NGTL believes that the in-depth review undertaken in the 2004 GRA provided parties with a sufficient level of understanding of and comfort with NGTL's current cost structure and forecasting methodologies to enable them to support a multi-year revenue requirement settlement. Additionally, the comprehensive, detailed 2005 GRA Phase 1 filed in December 2004 was available to for review by participants.

- The 2005 revenue requirement fixed under the terms of the Settlement will also result in lower costs to shippers than in 2004. Illustrative amounts for 2006 and 2007 indicate that costs are expected to continue to remain lower than 2004 costs.

- The Settlement provides a reasonable apportionment of risk on the fixed and flow-through cost components. NGTL is incented to achieve cost efficiencies which may result in sustained reductions in Operating Costs.

- The Settlement will result in greater regulatory efficiency and effectiveness than a traditional litigated hearing process. It defines a method for determining revenue requirements for a three-year period, which will decrease the time and resources that would otherwise be required by all parties to determine revenue requirement in each of the three years.

- The Settlement will provide greater rate certainty for shippers than a litigated GRA process by enabling NGTL to determine annual revenue requirements earlier in each of the years of the Settlement.
- The Settlement contains appropriate reporting and audit provisions to ensure proper information disclosure and accountability to parties to the Settlement and the Board.
- The Settlement allows for the determination of revenue requirements that will enable NGTL to operate the Alberta System safely, reliably, and cost effectively.
- The Settlement is consistent with the existing law and policies of the Board.

Accordingly, for these reasons, NGTL requests that the Board approve the Settlement in its entirety. NGTL submits that the Board, in approving the Settlement, will validate the significant efforts of the participants and will affirm the Board's stated commitment to the negotiated settlement process and its objectives of achieving greater regulatory efficiencies and effectiveness through that process.

Q16. Does that conclude NGTL's evidence in this section?

A16. Yes.

APPENDIX A: NGTL 2005-2007 REVENUE REQUIREMENT SETTLEMENT

NGTL 2005-2007 Revenue Requirement Settlement
March 1, 2005

1.0 OVERVIEW

This Settlement encompasses all elements of NGTL Revenue Requirement and does not extend to any rate design, accountability, services or competitive issues. This Settlement is based on establishing certain revenue requirement amounts and methodologies for calculation of the 2005, 2006 and 2007 Alberta System revenue requirements, including establishing deferral accounts for various revenues and costs. Rates for 2005, 2006, and 2007 will be based on the revenue requirement for that year and calculated in accordance with the methodology in effect at the time as approved by the EUB.

This Settlement fixes the overall revenue requirement amount for 2005 as set out in Appendix 1, which forms part of this Settlement. This Settlement also fixes some components of the 2006 and 2007 revenue requirements and provides for the overall revenue requirements for 2006 and 2007 to be determined through specified methodologies.

2.0 TERM

The term of this Settlement is three years commencing January 1, 2005 until December 31, 2007.

3.0 REVENUE REQUIREMENT COMPONENTS

The revenue requirement will be calculated for each year based on inclusion of certain costs that are fixed pursuant to this Settlement ("fixed cost components"), and a forecast of remaining costs that will flow through ("flow through cost components"), adjusted for appropriate deferral account balances.

3.1 Fixed Cost Components

The following cost amounts will be fixed for the three year period. Any variance between these forecasts and actual costs incurred will be for the account of NGTL.

(a) Operating Costs

Operating costs for 2005, 2006, and 2007, which include severance costs, will be fixed at the levels specified below. Actual severance costs for 2007 will be amortized over a two year period, 2007 and 2008. Fifty percent (50%) of the actual severance costs for 2007, will be deferred to 2008, up to a maximum of $2.5 million, and included in NGTL's 2008 revenue requirement.

2005	$193 million
2006	$201 million
2007	$207 million

(b) Other Costs

Other fixed cost components of the revenue requirement are foreign exchange on interest payments, uninsured losses, and amortization of severance costs incurred in the previous years under the terms of the 2003 Settlement. These costs for the three year period will be fixed as follows:

2005	$6 million
2006	$3 million
2007	$5 million

3.2 "Flow-through" Cost Components

The following cost amounts will be forecast at the beginning of each year and included in the calculation of revenue requirement. Any variance between the forecasts and actual costs incurred will be included in a deferral account and adjusted in the following year's revenue requirement. Carrying charges or credits on deferral accounts will be calculated using the Bank of Canada Bank Rate plus 1 1/2%.

(a) Rate Base

There will be a single rate base that is forecast each year and includes all rate base items (base rate base, general plant and maintenance capital, capacity capital, pipeline integrity, and CO_2 capital).

(b) Return on Equity

The return on equity is calculated annually using EUB formula on a deemed 35% equity component. For 2005, the forecast return on equity is $148 million. For 2006 and 2007, the forecast return on equity will be calculated by multiplying the EUB approved return on 35% deemed equity by the weighted average rate base for each year and is estimated to be $146 million and $139 for 2006 and 2007 respectively.

(c) Debt Expenses

Debt expenses will be calculated annually in the usual manner based on the average rate base, the terms of the existing long term debt and a forecast of unfunded debt costs. Debt expenses are forecast to be $226 million, $215 million, and $202 million for 2005, 2006, and 2007 respectively.

(d) Depreciation

The forecast depreciation expense will be calculated annually using the rates for individual asset classes included in the depreciation study filed in the NGTL 2004 GRA. The forecast depreciation expense for 2005 is $304 million and is estimated to be $285 million and $282 million for 2006 and 2007 respectively.

(e) Property, Income, and Large Corporation Taxes

Property taxes for 2005 are forecast at the 2004 level of $71 million and are assumed, for the purpose of providing an estimate of NGTL's revenue requirement, to be $71 million for each of 2006 and 2007. Income and Large Corporation taxes are calculated annually based on the EUB approved return on equity, the forecast weighted average rate base and applicable tax rates and other adjustments. For 2005 the forecast income and Large Corporation tax expense is $140 million and is estimated to be $132 million and $131 million for 2006 and 2007 respectively.

(f) Transportation by others

TBO costs will be forecast annually based on the following TBO arrangements:

Foothills Zone 6;
Foothills Zone 7;
Ventures Oil Sands Pipeline;
Husky Kearl Lake; and
ATCO East Edmonton.

For 2005 the forecast TBO cost for these existing TBO arrangements is $83,373,000 and is estimated to be $93 million and $91 million for 2006 and 2007 respectively. Costs associated with additional TBO arrangements, if any, will be flow through costs and added to the revenue requirement subject to the approval of the EUB.

(g) Regulatory hearing costs

The regulatory hearing cost reserve account established in the 2004 GRA Decision will be continued. NGTL will not carry a hearing cost reserve balance in excess of $5 million at any time. A forecast of the regulatory hearing costs will be included in the revenue requirement each year. For 2005 the forecast regulatory hearing cost amount is $4,452,000 and is estimated to be $2 million for each of 2006 and 2007..

(h) Pipeline Integrity costs (expense)

Pipeline integrity expenses will be forecast annually. For 2005, the forecast pipeline integrity expense is $19,923,000 and is estimated to be $13 million and $17 million for 2006 and 2007 respectively.

(i) Annual Foreign Exchange Amortization Amount

The mechanism established through the 2001-2002 Alberta System Rate Settlement for amortizing foreign exchange gains and losses related to long-term debt will continue. The Annual Foreign Exchange Amortization Amount will be forecast annually, to amortize foreign exchange gains and losses on long-term debt over the life of that debt. For 2005, the forecast Annual Foreign Exchange Amortization Amount is $1,620,000 and is estimated to be $2 million for each of 2006 and 2007.

(j) $C0_2$ Management Service costs (expense)

CO_2 Management Service expenses will be forecast annually. For 2005 the forecast CO_2 Management Service expense is $2,678,000 and is estimated to be $ 3 million for each of 2006 and 2007.

3.3 Audit Adjustment

The 2005 revenue requirement will be reduced by $6,248,000 to reflect the TTFP Resolution T2001-03.

3.4 Deferral Accounts

All deferral accounts approved by the Board in Decision 2004-069 and established by NGTL will be continued and balances in these accounts will be included in the subsequent year's revenue requirement including 2004 balances being carried forward to 2005. Other deferral accounts will be established as necessary to provide for flow through treatment of all flow-through cost components listed in Section 3.2 above.

4.0 OTHER PROVISIONS

4.1 Incentive Compensation

Upon EUB approval of this Settlement, NGTL will withdraw its Motion to the Alberta Court of Appeal for Leave to Appeal EUB Decision 2004-069 and NGTL will not pursue a review and variance application on the EUB findings on either the 2004 Incentive Compensation or Long Term Incentive Compensation costs.

4.2 Allocation of TransCanada Costs to NGTL

During the term of this Settlement, if there is a substantive change to the methodology used in 2004 to allocate corporate costs to NGTL, NGTL will notify the parties and the parties will enter into good faith negotiations to determine the appropriate adjustment, if any, to the revenue requirement.

4.3 Service Levels

NGTL will maintain, at a minimum, its current services (i.e. FT-R, FT-D, FT-A, etc) subject to any changes approved by the EUB. In addition, NGTL will use reasonable efforts to maintain its current level of customer service.

4.4 Facilities Divestitures or Acquisitions

If, in any year during the term of this Settlement, NGTL either divests of or acquires assets that result in a net decrease or increase of NGTL's rate base by $250 million or more and has a material impact on NGTL's Operating Costs, the parties will enter into good faith negotiations to determine the appropriate adjustment, if any, to the revenue requirement.

4.5 Reporting

On or before May 15th of each year following each of the Settlement years, NGTL will provide a report to the EUB and parties to this Settlement containing information which provides the same level of detail as the reporting package for the 2003 Alberta System Revenue Requirement Settlement. The report will also include a breakdown of TransCanada's corporate allocated costs to NGTL, the TransCanada Mainline, TransCanada's B.C. System, Foothills and Other.

4.6 Audit

The Tolls, Tariff, Facilities, and Procedures Committee (TTFP) may conduct an independent audit of this Settlement and will use reasonable efforts to complete it prior to December 15, 2008. The audit will verify compliance by NGTL with the terms of this Settlement and verify the validity of the information provided in the reporting packages. Subject to the execution of an acceptable confidentiality agreement by the auditor, NGTL will provide reasonable access to all necessary source data. The costs and expenses for the audit will be paid by NGTL and added to NGTL's subsequent year revenue requirement.

4.7 Net Negative Salvage

All parties agree to enter into industry wide discussions during the term of this Settlement on the terminal net negative salvage issue. Dispute resolution procedures referred to in Section 4.11 will not apply.

4.8 Long Term Debt

NGTL will consult with shippers, during the term of this Settlement, on the issue of its long term debt funding position. Dispute resolution procedures referred to in Section 4.11 will not apply.

4.9 Settlement Package

The parties agree that EUB approval of this Settlement in its entirety as a package is a requirement for this Settlement to be binding on any party. The terms and conditions of this Settlement have been negotiated and set no precedent nor shall they prejudice any position any party may take regarding the matters addressed in this Settlement in other proceedings or forums at any time.

4.10 Cost of Service Schedules

NGTL will, if requested by any party during its 2005 Phase 2 GRA process, provide forecast numbers for 2005 costs at the level provided in Tables 1 and 2 of its Cost of Service Study and include a breakdown of its forecast 2005 TBO costs.

4.11 Dispute Resolution

Any disputes under this Settlement that cannot be resolved through good-faith negotiations within 45 days (or longer if agreed by the parties) may be referred to the EUB by any party or the parties may agree to an alternate dispute resolution process.

4.12 Confidentiality

All information exchanged in this Settlement process is confidential and is provided on a without prejudice basis. NGTL will file this Settlement with the EUB for approval and may disclose the terms and conditions of this Settlement, as it determines necessary, in a press release.

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 9 day of March, 2005.

Company or Association Name (please print)

ANADARKO CANADA CORPORATION

Per: S. Grimbly

Title: Regulatory Affairs Advisor

Per:____________________

Title:____________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this _______day of March, 2005.

Company or Association Name (please print)

BP Canada Energy Company

Per: NL Lunde

Title: Lee Lunde
VP, Business Development & Strategy

Per:______________________________

Title:_____________________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 8th day of March, 2005.

Company or Association Name (please print)

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Per: ______________________

Title: VICE PRESIDENT

Per: ______________________

Title: ______________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 8th day of March, 2005.

Company or Association Name (please print)

John J. Mahony

TITLE ~~Per:~~ MANAGER REGULATORY AFFAIRS

Per ~~Title:~~ CARGILL POWER + GAS MARKETS

Per:____________________________

Title:___________________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 9 day of March, 2005.

Company or Association Name (please print)

EnCana Corporation

Per: K.J. Hadley

Title: Director, Regulatory Services

Per:____________________

Title:____________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this _7th_ day of March, 2005.

Company or Association Name (please print)

INDUSTRIAL GAS CONSUMERS ASSOCIATION OF ALBERTA

Per: ____________________

Title: EXECUTIVE DIRECTOR

Per: ____________________

Title: ____________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 8th day of March, 2005.

Company or Association Name (please print)

NOVA Gas Transmission Ltd.

Per: S. Bohlod

Title: Director, Western Market Development

Per: M Feldman

Max Feldman

Title: Vice President
Gas Transmission West

5.0 EXECUTION

A fax signature shall be deemed to be an original This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 9th day of March, 2005.

Company or Association Name (please print)

Pacific Gas and Electric Company

Per: D. Ellerton

Title: Canadian Representative

Per:______________________________

Title:______________________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 14TH day of March, 2005.

Company or Association Name (please print)
PUGET SOUND ENERGY

Per: Wayne [signature]

Title: DIRECTOR NATURAL GAS RESOURCES

Per: ______________________

Title: ______________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 9 day of March, 2005.

Company or Association Name (please print)

SEPAC

Per: RON VOGEL

Title: Chairman, NATURAL GAS COMMITTEE

Per: Ron Vogel

Title:

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 8th day of March, 2005.

Company or Association Name (please print)

TALISMAN ENERGY INC.

Per:

Title: Manager, Regulatory Affairs

Per:____________________

Title:____________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 8 day of March, 2005.

Company or Association Name (please print)

Terasen Gas. Inc.

Per: J. A. Marston, Vice President

Title: Gas Supply & Transmission

Per: ______________________

Title: ______________________

5.0 EXECUTION

A fax signature shall be deemed to be an original. This Settlement may be executed in many counterparts and all executed counterparts shall constitute one Settlement.

The executing parties agree to all of the terms and conditions of this Settlement this 9 day of March, 2005.

Company or Association Name (please print)

Utilities Consumer Advocate

Per:

Title: Executive Director, Regulatory Affairs

Per:

Title:

Appendix 1

This table summarizes the fixed costs agreed to in this Settlement and provides an illustration of the flow-through costs. This table does not include deferral account balances from 2004 or projected deferral account balances related to 2005, 2006, and 2007. The final revenue requirement for each year, including 2005, will be adjusted to include all deferral account balances from the previous year.

$ millions		**2005**	**2006**	**2007**
Fixed Costs	Operating Costs	193	201	207
	Other Fixed Costs	6	3	5
	Total Fixed Costs	199	204	212
Flow Through Costs	Equity Return	148	146	139
	Debt Expense	226	215	202
	Depreciation Expense	304	285	282
	Property Taxes	71	71	71
	Other	253	245	247
	Total Flow Through	1,002	962	941
	Total Revenue Requirement	1,201	1,166	1,153

APPENDIX B: INVITATION TO PARTICPATE IN SETTLEMENT NEGOTIATIONS

TransCanada
In business to deliver
TransCanada PipeLines Limited

tel 403-920-5844
fax 403-920-2384
email steve_pohlod@transcanada.com
web www.transcanada.com

November 8, 2004

TO: **All Interested Parties**

FROM: **NOVA Gas Transmission Ltd.**

RE: **2005 Revenue Requirement Settlement Negotiations**

On August 18, 2004, NOVA Gas Transmission Ltd. (NGTL) applied to the Alberta Energy and Utilities Board (Board) for approval to initiate negotiations with respect to its revenue requirement or components of its revenue requirement for a term of up to five years pursuant to the Board's Negotiated Settlement Guidelines. NGTL indicated that the scope and term of the negotiation would be addressed by the parties to the negotiations.

The Board approved NGTL's request to commence negotiations on September 10, 2004 provided that the settlement period not exceed three years commencing January 1, 2005. The scope, term, basis for and timing of settlement negotiations proposed by NGTL is outlined in Attachment 1. The Canadian Association of Petroleum Producers and the Industrial Gas Consumers Association of Alberta have indicated that they are prepared to enter into settlement discussions. The Board was informed by letter dated October 22, 2004 that NGTL remains committed to either filing a negotiated settlement or a General Rate Application (GRA) for Board approval on a timely basis and intends to do so before the end of 2004.

NGTL is inviting the members of the Tolls, Tariff, Facilities and Procedures Committee, parties to NGTL's 2004 GRA Phases 1 and 2 and all Alberta System Shippers to participate in the settlement negotiations. Pursuant to the Board's Negotiated Settlement Guidelines, NGTL is also inviting Board staff to observe the negotiations.

A meeting to present NGTL's settlement proposal and provide additional details and background information will be held on Wednesday, November 17, 2004 from 2:00 pm to 4:00 pm in Room 214 (+15 level) at TransCanada Tower, 450 – 1 Street SW, Calgary. Please respond to this invitation by notifying Sharon Wright at 403-920-7016 or by email at sharon_wright@transcanada.com by 4:00 pm on Friday, November 12, 2004 to ensure that all interested parties can be comfortably accommodated.

Sincerely,

S Pohlod

Steve Pohlod
Director, Western Market Development
Gas Transmission West

Attachment

cc: Alberta System Shippers
Parties to NGTL's 2004 GRA Phases 1 and 2
Tolls, Tariff, Facilities & Procedures Committee
Alberta Energy and Utilities Board

Attachment 1

NGTL Revenue Requirement Settlement (Post-2004) Proposed Scope and Timing

Scope: The settlement would encompass all elements of NGTL's Revenue Requirement. It would not extend to rate design, accountability, services or competitive issues.

Term: The settlement would cover a two-year (2005/2006) or three year (2005-2007) period.

Basis for Negotiation:

a) **Return on Equity:** Calculated in accordance with EUB Generic Cost of Capital Decision (EUB formula on deemed 35% equity component).

b) **Depreciation:** Based on rates supported by depreciation study filed by NGTL in the 2004 GRA. No provision for terminal net negative salvage. However, separate discussions that are not tied to the settlement would be initiated regarding this issue during the term of the settlement.

c) **Income Taxes:** Based on continuation of flow-through methodology with no amortization of existing deferred amounts.

d) **OM&A:** Global amount to be determined by negotiating parties.

Timing: The parties to make reasonable efforts to reach a settlement in principle by November 30, 2004 with final documentation and filing targeted for December 15, 2004.

APPENDIX C: LIST OF PARTICIPANTS IN SETTLEMENT NEGOTIATIONS

List of Parties that Attended the First Negotiations Meeting on November 17, 2004

Alberta Department of Energy

Alberta Energy and Utilities Board

Anadarko Canada Corporation

Apache Canada Ltd.

ATCO Pipelines

Avista Corporation

BP Canada Energy Company

Burlington Resources Canada Partnership

Cargill Power & Gas Markets

Consumers' Coalition of Alberta

Coral Energy Canada Inc.

EnCana Corporation

Export Users Group

Exxon Mobil Canada Ltd.

Imperial Oil Resources Ltd.

Industrial Gas Consumers Association of Alberta

Nexen Inc.

NOVA Gas Transmission Ltd.

Pacific Gas & Electric Company

Portland General Electric Company

Puget Sound Energy, Inc.

Shell Canada Limited

Suncor Energy Inc.

Syncrude Canada Ltd.

Talisman Energy Inc.

Terasen Gas Inc.

Unocal Canada Limited

Utilities Consumer Advocate

List of Parties that Signed the Confidentiality Agreement

Alberta Energy and Utilities Board

Alberta Urban Municipalities Association

Anadarko Canada Corporation

ATCO Pipelines

Avista Corporation

Avista Energy Canada, Ltd.

BP Canada Energy Company

Burlington Resources Canada Partnership

Canadian Association of Petroleum Producers

Cargill Power & Gas Markets

Cascade Natural Gas Corporation

Consumers' Coalition of Alberta

Coral Energy Canada Inc.

EnCana Corporation

Imperial Oil Resources Ltd.

Industrial Gas Consumers Association of Alberta

Nexen Inc.

Northwest Natural Gas Company

NOVA Gas Transmission Ltd.

Pacific Gas & Electric Company

Petro Canada Oil and Gas

Portland General Electric Company

Puget Sound Energy, Inc.

Small Explorers and Producers Association of Canada

Suncor Energy Inc.

Talisman Energy Inc.

Terasen Gas Inc.

Utilities Consumer Advocate

APPENDIX D: LETTERS OF COMMENT FROM PARTICIPANTS

BARRISTERS · SOLICITORS

Bryan & Company

GEORGE J BRYAN Q C 1900-1975

OUR FILE: 18489-76
YOUR FILE:

PLEASE REPLY TO EDMONTON OFFICE
DIRECT: (780) 420-4704
E-MAIL: jabryan@bryanco.com

March 10, 2005

SENT VIA FAX: 403-920-2317

TransCanada Pipelines Limited
450 - 1st Street SW
Calgary, Alberta T2P 5H1

ATTENTION: Mr. Steve Pohlod, Director, Western Market Development

Dear Sir:

RE: NGTL 2005-2007 REVENUE REQUIREMENT SETTLEMENT

This letter is to confirm that the Environment and Utilities Standing Committee of the Alberta Urban Municipalities Association (AUMA) has approved the settlement arrangements and recommended that the Board of Directors authorize execution of the settlement document which was attached to your letter of March 1, 2005.

We have every expectation that the AUMA Board will approve this settlement at its next meeting scheduled for March 24, 2005 and can advise that the AUMA will not oppose NGTL's application for approval of the negotiated settlement.

Yours truly,

BRYAN & COMPANY

J Alan Bryan, Q.C

JAB/crf

ATCO Pipelines
909 – 11 Avenue SW Calgary AB T2R 1L8 Phone (403) 245-7060 Fax (403) 245-7844

March 5, 2005

Mr. Steve Pohlod
Director, Western Market Development
NOVA Gas Transmission Ltd.
450-1st Street S.W.
Calgary, AB T2P 5H1

Dear Mr. Pohlod:

Re: NOVA Gas Transmission Ltd. (NGTL) 2005-2007 Revenue Requirement Settlement

ATCO Pipelines (ATCO) has reviewed the NGTL 2005-2007 Revenue Requirement Settlement and it does not oppose this agreement as a settlement package. ATCO specifically supports the inclusion of the costs related to the ATCO East Edmonton Transportation By Others (TBO) Agreement in the 2005-2007 revenue requirements. While ATCO does have some concerns about other TBO agreements which are referred to in this settlement package, it appears that these concerns would be best addressed in either NGTL's 2005 Phase II Application or the Competitive Proceeding.

Yours truly,

Ed Jansen, CA
Senior Manager, Regulatory

bp

BP Canada Energy Company
240 - 4 Avenue S W
P O Box 200
Calgary Alberta T2P 2H8
Direct: (403) 233-1569

March 10, 2005

TransCanada PipeLine Ltd.
450 – 1st Street S.W.
Calgary, Alberta
T2P 5H1

Attention: Mr. Steve Pohlod

Dear Mr. S. Pohlod

Re: NGTL 2005 – 2007 Revenue Requirement Settlement

BP Canada Energy Company (BP Canada) is a large shipper on the NGTL system and was an active participant in the recent negotiations of the NGTL 2005 - 2007 Revenue Requirement Settlement (the Settlement) both on its own behalf and as a member of CAPP. BP has reviewed the settlement document and has decided that it will sign the Settlement as a show of support. In doing so however, given that many of the cost elements of the settlement are defined as flow through, BP Canada believes it is important to be clear with respect to its understanding of flow through costs in the settlement. In this regard, BP fully endorses the comment in the support letter from CAPP which states "flow through costs in this settlement are reasonable estimates of the actual costs that as prudently occurred will flow through to shippers".

If you have any questions or require any additional information, please call me at (403) 233-1569.

Sincerely,

Cheryl G Worthy

Cheryl G. Worthy
Director, Regulatory Affairs

Attachment

CAPP

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

March 8, 2005

Steve Pohlod
Director, Western Market Development
TransCanada Pipelines
450 1st Street SW
Calgary, Alberta T2p 5H1

Dear Steve:

Re: NGTL Settlement for 2005 to 2007

Attached please find the signed execution page for the NGTL settlement on behalf of the Canadian Association of Petroleum Producers (CAPP). As discussed, CAPP requests that in addition to this settlement document that NGTL include the following wording in the application for the settlement to the Alberta Energy and Utilities Board:

The flow through costs in this settlement are reasonable estimates of the actual costs that, as prudently incurred, will flow through to shippers.

We appreciate the hard work on behalf of NGTL and all stakeholders that went into achieving this settlement.

Sincerely,

Greg Stringham
Vice President

attachment

cc: CAPP NGTL Committee
CAPP Markets and Transportation Executive Policy Group

2100, 350–7th Ave S W
Calgary Alberta
Canada T2P 3N9
Tel (403) 267-1100
Fax (403) 261-4622

230, 1801 Hollis Street
Halifax Nova Scotia
Canada B3J 3N4
Tel (902) 420-9084
Fax (902) 491-2980

905 235 Water Street
St John's Newfoundland
Canada A1C 1B6
Tel (709) 724-4200
Fax (709) 724-4225

Email: communication@capp ca Website: www capp ca

Wachowich & Company
Barristers & Solicitors

The Melton Building
555, 10310 - Jasper Avenue
Edmonton, Alberta T5J 2W4
Tel: (780) 429-0555
Fax: (780) 425-4795
mail@wachowich.com

James A. Wachowich
Andrew T. Holko
Richard R. Mirasty

March 11, 2005

Nova Gas Transmission Ltd.

Via e-mail

Attention: S. Pohlod

Dear Sir:

RE: 2005-2007 NGTL Revenue Requirement Settlement

Our office acts for the Consumers' Coalition of Alberta (CCA), which is comprised of the Consumers' Association of Canada (Alberta Division), and the Alberta Council on Aging.

Our office has received instructions and advises the CCA supports the settlement of this matter.

If you have any questions respecting this, please contact the writer.

Yours truly,

WACHOWICH & CO.

Per:
JAMES A. WACHOWICH
JAW/
CC – Jeff Jodoin

OUR FILE: 18489-76
YOUR FILE:

PLEASE REPLY TO EDMONTON OFFICE
DIRECT: (780) 420-4704
E-MAIL: jabryan@bryanco.com

BARRISTERS · SOLICITORS

Bryan & Company

GEORGE J. BRYAN Q.C. 1900-1975

March 11, 2005

SENT VIA FAX: 403-920-2384

TransCanada Pipelines Limited
450 - 1st Street SW
Calgary, Alberta T2P 5H1

ATTENTION: Mr. Steve Pohlod, Director, Western Market Development

Dear Sir:

RE: NGTL 2005-2007 REVENUE REQUIREMENT SETTLEMENT

This letter is to confirm that the Consumer Group were active participants in this process, through designated representatives, and to advise as to their position regarding the negotiated settlement.

The Public Institutional Consumers of Alberta (PICA), the Consumers' Coalition of Alberta (CCA) and the Federation of Alberta Gas Co-ops Ltd. and Gas Alberta Inc. (FGA) support the settlement that has been reached. Consultants for the remaining members, being the Alberta Urban Municipalities Association (AUMA) and the Aboriginal Communities (AbCom), have recommended support which is expected to be given in the ordinary course but, because of timing constraints, cannot be formally given at this time. They are, however, not opposed to the settlement and your application for approval by the Board.

Signed copies of the settlement agreement will be provided to you by the individual members.

Yours truly,

BRYAN & COMPANY

J Alan Bryan, Q.C.

JAB/crf

APPENDIX E: REVENUE REQUIREMENT SUMMARY

REVENUE REQUIREMENT SUMMARY
($Thousands)

Line No.	Description	Approved GRA 2004	Applied-for GRA 2005	Settlement 2005
1	Fixed Cost Components			
2	Operating Costs	180,334	197,955	193,000
3	Other Costs [1]	18,275	6,431	6,000
4	Total Fixed Cost Components	198,609	204,386	199,000
5	Flow-through Cost Components			
6	Return on Equity	154,929	148,222	148,000
7	Debt Expenses	241,241	229,510	226,000
8	Depreciation	296,064	304,203	304,000
9	Property, Income, and Large Corporation Taxes	208,108	212,909	211,000
10	Transportation by Others	81,883	83,373	83,373
11	Regulatory Hearing Costs	4,372	4,452	4,452
12	Pipeline Integrity Costs (expense)	19,565	19,923	19,923
13	Annual Foreign Exchange Amortization Amount	4,837	1,620	1,620
14	CO_2 Management Service Costs (expense)	2,707	2,678	2,678
15	CO_2 Management Service Costs (capital cost recovery) [2]	126	177	-
16	Audit Adjustment	-	(6,248)	(6,248)
17	Deferral Accounts	32,363	(33,569)	(33,840)
18	Total Flow-through Cost Components	1,046,195	967,250	960,958
19	Total Revenue Requirement	1,244,804	1,171,636	1,159,958

Notes:

[1] Other Costs include foreign exchange on interest payments, uninsured losses, and amortization of severance costs incurred in previous years under the terms of the 2003 Settlement.

[2] Included in return on equity, debt expenses, depreciation and property, income and Large Corporation taxes for 2005 under the terms of the Settlement.

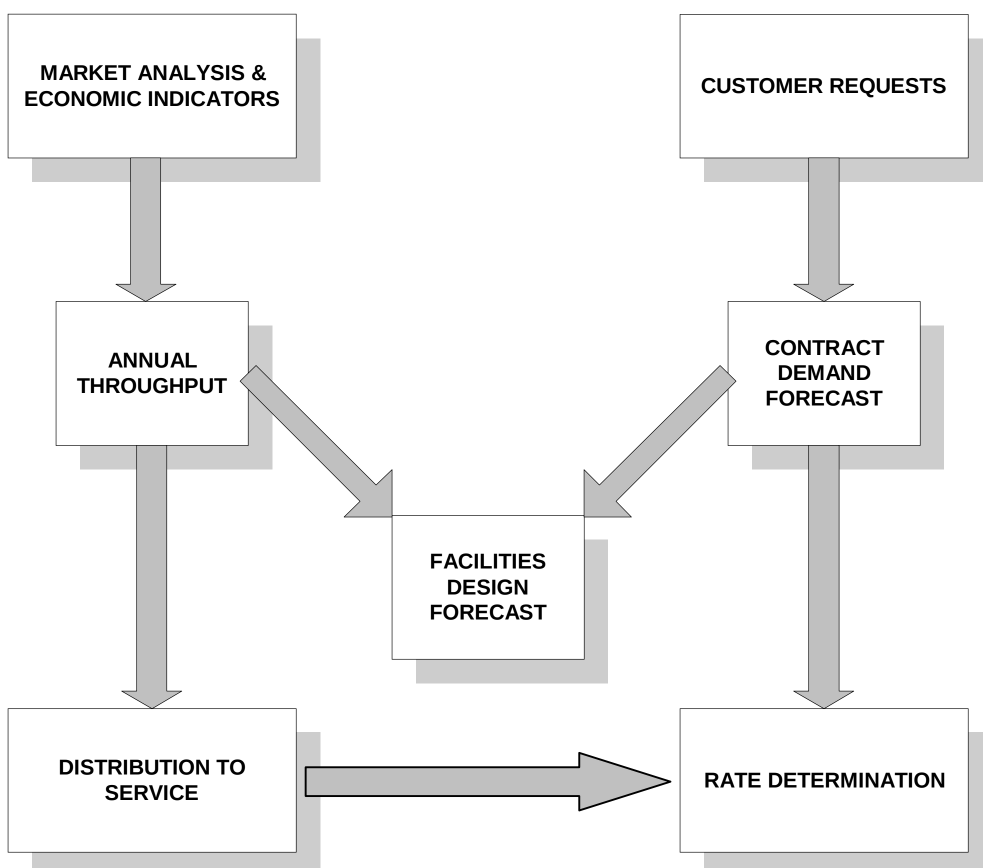
APPENDIX F: 2005 CONTRACT DEMAND QUANTITY AND THROUGHPUT

1.0 CONTRACT DEMAND QUANTITY AND THROUGHPUT

1.1 OVERVIEW

In this Section, NGTL provides Contract Demand Quantity and Throughput information for the purposes of determining the 2005 illustrative rates, tolls and charges in Appendix G. The following flow chart outlines the interrelationship between Firm Transportation Contract Demand, Annual Throughput, the Facilities Design Forecast, and rate determination.

Figure 1-1



A forecast of Firm Transportation Contract Demand is used in the determination of the Firm Transportation Demand rate, from which approximately 75 percent of Alberta System revenue is recovered. Firm Transportation Contract Demand is forecast through an assessment of customer requests for Firm Transportation at Receipt and Delivery Points after consideration of contract renewals, current market conditions and downstream pipeline expansions. The 2005 average Receipt Point Contract Demand (which includes all Firm Services contracted at receipt points) is forecast to be 258.9 $10^6m^3/d$ (9.19 Bcf/d). The 2005 average Export Delivery Point Contract Demand (which includes all Firm Services contracted at export delivery points) is forecast to be 228.1 $10^6m^3/d$ (8.10 Bcf/d).

Throughput is forecast through an assessment of market demand in all markets served by Canadian gas, a projection of the available capacity, and system load factors on all interconnecting downstream pipelines. Considerable input in this process is received from Alberta System customers, downstream pipeline operators, industry associations, and the end-users of Canadian gas to determine the annual throughput forecast. The 2005 average Annual Throughput for the Alberta System is forecast to be 308.2 $10^6m^3/d$ (10.94 Bcf/d).

The forecasts of the 2005 Annual Throughput and Firm Transportation Contract Demand are used in the determination of Interruptible Transportation service. The volume flowing under Interruptible Transportation service is determined by taking the total Annual Throughput and subtracting the volume forecast to flow under Firm Transportation service. Since not all Firm Transportation Contracts are fully utilized, projected system load factors are applied to determine the volume flowing under Firm Transportation service.

1.2 FIRM TRANSPORTATION

There are two primary categories of Firm Transportation Contracts (Receipt and Delivery) available on the Alberta System. Firm Transportation Receipt Point Contracts refer to quantities contracted by customers under Firm Transportation agreements that enter the Alberta System at receipt meter stations. Firm Transportation Export Delivery Point Contracts refer to quantities contracted by customers under Firm Transportation agreements that leave the Alberta System to another province or state. Alberta Delivery Point Contracts refer to quantities that leave the Alberta System to a market within Alberta.

1.2.1 Firm Transportation Receipt Point Contract Demand

The Receipt Point Contract Demand forecast is determined after considering the total quantity contracted by customers under Firm Transportation agreements, and adjustments for any new and expiring Contract Demand forecast to occur during 2005. Quantities used in the forecast are based on information available as of the end of December 2004. The adjustments result from the following:

1. New Receipt Point Contract Demand – Tables 1.2-1 and 1.2-2 include the estimated quantity of new Firm Transportation contracts during 2005.

2. The non-renewal of Receipt Point Contract Demand – The Gas Transportation Tariff requires customers to provide renewal commitments one year prior to the expiration of a contract. Contract renewals are known up until the end of December 2005. Tables 1.2-1 and 1.2-2 include the non-renewal information.

The total Receipt Point Contract Demand illustrated in Table 1.2-1 shows a decrease from 256.5 $10^6m^3/d$ (9.11 Bcf/d) at the beginning of the year to 255.4 $10^6m^3/d$ (9.06 Bcf/d) at the end of the 2005. The 2005 average Receipt Point Contract Demand, which is calculated as an average of twelve monthly forecasts, is forecast to be 258.9 $10^6m^3/d$ (9.19 Bcf/d). The monthly forecast detail used to calculate the 2005 average Receipt Point Contract Demand forecast is shown in Table 1.2-2. Table 1.2-1 also includes figures for 2003 and 2004.

Table 1.2-1[1]
2003-2005 Firm Transportation Receipt Point Contract Demand

	2003 Actual		**2004 Actual**		**2005 Forecast**	
Receipt Contract Demand	**Bcf/d**	**$10^6m^3/d$**	**Bcf/d**	**$10^6m^3/d$**	**Bcf/d**	**$10^6m^3/d$**
Beginning of Year	10.4	292.3	9.1	257.4	9.1	256.5
Adjustments						
• New Firm Transportation	0.5	12.7	1.7	46.5	2.1	58.9
• Non-Renewals	(1.7)	(47.6)	(1.7)	(47.4)	(2.1)	(59.8)
End of Year	9.1	257.4	9.1	256.5	9.1	255.4
Average Monthly Quantity	**9.8**	**275.8**	**9.4**	**265.0**	**9.2**	**258.9**

Note:
1. Numbers may not add due to rounding.

Table 1.2-2[1]

2005 Monthly Firm Transportation Receipt Point Contract Demand

(Bcf/d)

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Previous Month-End	9.11	9.29	9.39	8.12	8.80	9.05	9.15	9.15	9.19	9.20	8.80	8.96
Estimated Incremental Receipt	0.22	0.15	0.03	0.76	0.29	0.12	0.04	0.06	0.02	0.08	0.19	0.12
Start of Month	9.32	9.44	9.42	8.88	9.09	9.17	9.19	9.21	9.22	9.28	8.99	9.08
Less Non-Renewals	0.03	0.06	1.30	0.08	0.04	0.02	0.04	0.02	0.01	0.48	0.02	0.02
End of Month	9.29	9.39	8.12	8.80	9.05	9.15	9.15	9.19	9.20	8.80	8.96	9.06
Monthly Average (Start of Month)				9.19								

(10^6 m^3/d)

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Previous Month-End	256.5	261.8	264.5	228.8	247.9	255.0	257.8	257.7	258.9	259.3	247.9	252.5
Estimated Incremental Receipt	6.1	4.3	0.9	21.4	8.2	3.4	1.2	1.8	0.7	2.1	5.3	3.3
Start of Month	262.6	266.0	265.4	250.2	256.0	258.4	258.9	259.5	259.6	261.5	253.2	255.8
Less Non-Renewals	0.9	1.6	36.6	2.4	1.0	0.6	1.2	0.6	0.3	13.6	0.6	0.4
End of Month	261.8	264.5	228.8	247.9	255.0	257.8	257.7	258.9	259.3	247.9	252.5	255.4
Monthly Average (Start of Month)				258.9								

Note:
1. Numbers may not add due to rounding.

1.2.2 Firm Transportation Export Delivery Point Contract Demand

The Export Delivery Point Contract Demand is determined after considering the total quantity signed by customers under Firm Transportation agreements for the 2004/05 and 2005/06 Gas Years, and adjustments for any new and expiring Contract Demand forecast to occur during 2005. Components of the total 2005 Export Delivery Point Contract Demand of 228.1 $10^6m^3/d$ (8.10 Bcf/d) are shown in Table 1.2-3. Figures are also included for 2003 and 2004. The monthly forecast detail used to calculate the 2005 average Export Delivery Point Contract Demand forecast is shown in Table 1.2-4.

Table 1.2-3[1]
2003-2005 Firm Transportation Export Delivery Point Contract Demand

	2003 Actual		2004 Actual		2005 Forecast	
Export Delivery Point	**Bcf/d**	**$10^6m^3/d$**	**Bcf/d**	**$10^6m^3/d$**	**Bcf/d**	**$10^6m^3/d$**
Empress	3.57	100.6	3.17	89.4	3.38	95.3
McNeill	2.27	64.0	2.16	60.8	1.77	49.8
Alberta/B.C.	2.83	79.8	2.97	83.7	2.91	82.0
Other Borders [2]	0.04	1.0	0.04	1.0	0.04	1.0
Total Average Quantity	**8.72**	**245.5**	**8.34**	**235.0**	**8.10**	**228.1**

Notes:
1. Numbers may not add due to rounding.
2. 2003 Values include STFT at Alberta-Montana.

Table 1.2-4[1]

2005 Monthly Firm Transportation Export Delivery Point Contract Demand

(Bcf/d)

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Previous Month-End	8.28	8.30	8.29	8.24	8.19	8.12	8.02	7.92	7.87	7.87	5.82	8.03
Estimated Incremental FT-D	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.22	0.00
Start of Month	8.30	8.30	8.29	8.24	8.19	8.12	8.02	7.92	7.87	7.87	8.04	8.03
Less Non-Renewals	0.00	0.01	0.05	0.05	0.08	0.10	0.09	0.05	0.00	2.05	0.00	0.01
End of Month	8.30	8.29	8.24	8.19	8.12	8.02	7.92	7.87	7.87	5.82	8.03	8.02

Monthly Average (Start of Month) 8.10

(10^6 m^3/d)

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Previous Month-End	233.4	233.7	233.5	232.1	230.8	228.6	225.8	223.2	221.7	221.7	164.0	226.3
Estimated Incremental FT-D	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.5	0.0
Start of Month	233.7	233.7	233.5	232.1	230.8	228.6	225.8	223.2	221.7	221.7	226.4	226.3
Less Non-Renewals	0.0	0.2	1.4	1.3	2.1	2.8	2.7	1.5	0.0	57.7	0.1	0.4
End of Month	233.7	233.5	232.1	230.8	228.6	225.8	223.2	221.7	221.7	164.0	226.3	226.0

Monthly Average (Start of Month) 228.1

Note:
1. Numbers may not add due to rounding.

1.3 ANNUAL THROUGHPUT

1.3.1 Background

NGTL delivers gas to markets within Alberta and to downstream pipelines that connect to other Canadian and United States markets. Throughput forecasts are prepared for the following Export Border Points and Alberta Delivery Points on the Alberta System:

- Empress border, which connects with TransCanada's Mainline system and supplies gas to Canadian markets east of Alberta, the U.S. Midwest and U.S. Northeast markets;
- McNeill border, which connects with Foothills Pipe Lines (Sask.) Ltd., which, in turn, connects to Northern Border Pipeline Company and supplies the U.S. Midwest market;
- Alberta-B.C. border, which connects with TransCanada's B.C. System and supplies southern B.C. markets, and also connects with TransCanada's Gas Transmission Northwest (GTN) pipeline system and supplies the Pacific Northwest and California markets;
- Unity and Cold Lake borders, which connect with TransGas Limited and supply the Saskatchewan market;
- Gordondale and Boundary Lake borders, which connect with the Duke Energy Gas Transmission system and supply the British Columbia and Pacific Northwest markets;
- Alberta-Montana border, which connects with NorthWestern Energy's system and supplies the Montana market; and
- Alberta delivery stations.

NGTL's forecast is based on economic growth assumptions in Canada and the United States and an analysis of the aggregate supply, competition for supply with other pipelines, gas market share expectations, taking into account customer delivery contracts, downstream pipeline capacity, and competitiveness of Canadian gas versus other sources of gas.

1.3.2 Throughput by Alberta System Delivery Point

The following table summarizes the Annual Throughput forecast for the Alberta System by Delivery Point. Total Alberta System deliveries are forecast to remain relatively flat as illustrated in the following table.

Table 1.3-1[1]
Alberta System Throughput Forecast

	2003 Actual		2004 Actual		2005 Forecast	
Delivery Point	**Bcf**	**10^9m^3**	**Bcf**	**10^9m^3**	**Bcf**	**10^9m^3**
Empress	1,887	53.2	1,799	50.7	1,717	48.4
McNeill	777	21.9	768	21.6	773	21.8
Alberta/B.C.	673	19.0	743	20.9	761	21.5
Other Borders	6	0.2	9	0.3	9	0.2
Sub-Total Borders	**3,344**	**94.2**	**3,320**	**93.5**	**3,260**	**91.9**
Intra-Alberta	539	15.2	589	16.6	699	19.7
Total System (excl. Fuel)	**3,883**	**109.4**	**3,909**	**110.1**	**3,960**	**111.6**
Fuel	34	1.0	34	0.9	33	0.9
Total System (incl. Fuel)	**3,917**	**110.4**	**3,943**	**111.1**	**3,992**	**112.5**

Note:
1. Numbers may not add due to rounding.

The 2005 throughput at Export Delivery Points is forecast to decrease by 1.8% from 2004, while throughput at Alberta Delivery Points is forecast to increase by 18.7 %. The 2005 total system Annual Throughput is forecast to increase only slightly (1.2 %) from 2004.

1.3.3 Distribution of 2005 Annual Throughput to Services

Annual throughput is made up of gas volumes flowing under the following transportation services:

- Receipt Services (FT-R, FT-RN, IT-R);
- Delivery Services (FT-D, FT-DW, STFT, FT-A, IT-D); and
- Other Transportation Services (LRS, LRS-2, LRS-3, FT-P).

The various Firm and Interruptible service options available to customers combined with market volatility make it difficult to accurately forecast the utilization of these services. The forecast distribution of throughput by service type shown in Tables 1.3-2 and 1.3-3 is based upon historical use, trend analysis, and NGTL's judgment of its customers' use of these services. The throughput numbers shown below correspond to the 2005 calendar year. Throughput numbers used for calculating transportation rates are based on volumes forecast for the 12-month period from December 1 to November 30.

Table 1.3-2[1]

2005 Receipt Throughput by Service

Throughput Service Category	Bcf	10^9m^3	Percent of Annual Throughput
Firm Transportation Receipts*	2,782	78.4	69.7%
Interruptible Transportation Receipts	756	21.3	18.9%
Other Transportation Services**	410	11.6	10.3%
Total Services	3,948	111.3	98.9%
Net Receipts from Storage	44	1.2	1.1%
Total Throughput	**3,992**	**112.5**	**100.0%**

Notes:
1. Numbers may not add due to rounding.
* Includes fuel, FT-R and FT-RN
** Includes LRS, LRS-2, LRS-3 and FT-P

Table 1.3-3[1]

2005 Delivery Throughput by Service

Throughput Service Category	**Bcf**	**10^9m^3**	**Percent of Annual Throughput**
Firm Transportation Deliveries	2,885	81.3	72.3%
Interruptible Transportation Deliveries*	375	10.6	9.4%
Firm Transportation Alberta Deliveries**	699	19.7	17.5%
Total Delivery Services	3,960	111.6	99.2%
NGTL Fuel	33	0.9	0.8%
Total Throughput	**3,992**	**112.5**	**100.0%**

Notes:
1. Numbers may not add due to rounding.
* Volumes are net of Alternate Access
** Includes volumes from FT-P, FT-A, Extraction and Taps

APPENDIX G: 2005 ILLUSTRATIVE RATES, TOLLS AND CHARGES

1.0 2005 ILLUSTRATIVE RATES, TOLLS AND CHARGES

1.1 RATES, TOLLS AND CHARGES SUMMARY

This Appendix contains the illustrative rates, tolls and charges for all services for 2005.

NGTL calculated these rates in accordance with the rate design approved by the Board in Decision 2004-097 and contract demand and throughput quantities outlined in Appendix F and the 2005 revenue requirement determined under the terms of the Settlement and provided in Appendix E.

Figure 1.1-1 provides an overview of the rate calculation process.

Table 1.1-1 provides a comparison by service type between the illustrative 2005 rates and the final 2004 rates. The differences are primarily due to the decrease in revenue requirement from 2004 to 2005.

Table 1.1-2 (including Attachments 1 and 2) contains the illustrative rates based on a January 1 implementation date.

1.2 ILLUSTRATIVE 2005 RATES , TOLLS AND CHARGES

Figure 1.1-1 - 2005 Illustrative Rate Calculation

TOTAL REVENUE REQUIREMENT	$1,160.0 Million

MINUS

NON TRANSPORTATION REVENUE	$Million
FCS	$ 4.9
OS	$ 1.1
PT	$ 0.9
CO_2	$ 15.4
Total	$ 22.3

EQUALS

TRANSPORTATION REVENUE REQUIREMENT	$1,137.6 Million

MINUS

LRS REVENUE*	(Bcf/d)	($10^6m^3/d$)	$Million
LRS-1	0.65	18.45	$43.3
LRS-2	0.04	1.05	$ 0.7
LRS-3	0.05	1.41	$ 3.3
Total	0.74	20.91	$47.3

*Revenues adjusted to account for NGTL's contribution.

MINUS

OTHER TRANSPORTATION REVENUE

	(Bcf/d)	($10^6m^3/d$)	$Million
IT-D*	1.04	29.36	$ 64.8
STFT	0.00	0.00	$ 0.0
IT-R	2.07	58.37	$123.6
FT-P	0.38	10.73	$ 22.1
FT-RN	0.07	1.91	$ 5.2
FT-DW	0.00	0.00	$ 0.0
FT-A	1.03	28.92	$ 5.3
Total	4.59	129.29	$ 221.1

*Revenues adjusted to account for Alternate Access.

EQUALS

FIRM TRANSPORTATION REVENUE REQUIREMENT	$869.1 Million

Figure 1.1-1 cont'd. - 2005 Illustrative Rate Calculation

FIRM TRANSPORTATION REVENUE REQUIREMENT $869.1 Million

DIVIDED BY

CONTRACT DEMAND	(Bcf/)	($10^6m^{3)}$
Delivery	2,684.74	75,639.9
Receipt	2,920.10	82,271.0
Total	5,604.85	157,910.9

EQUALS

FIRM TRANSPORTATION PRICE $0.1551/Mcf/d $5.504/$10^3m^3$/d

MULTIPLIED BY

RECEIPT CONTRACT DEMAND

2,920.10 Bcf 82,271.0 10^6m^3

EQUALS

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT

$452.8 Million

MULTIPLIED BY

DELIVERY CONTRACT DEMAND

2,684.74 Bcf 75,639.9 10^6m^3

EQUALS

FIRM TRANSPORTATION DELIVERY REVENUE REQUIREMENT

$416.3 Million

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT $452.8 Million

ALLOCATE TO EACH RECEIPT POINT

RECEIPT TRANSPORTATION REVENUE

	Revenue ($Millions)	volumes (Bcf/d)	(10^6m^3/d)	Average ($/Mcf/d)	Price ($/$10^3m^3$/d)
1 Year Receipt	$000.0	0.00	00.00	0.163	5.779
3 Year Receipt	$452.8	8.00	225.40	0.155	5.504
5 Year Receipt	$000.0	0.00	00.00	0.147	5.229
Firm Receipt	$452.8	8.00	225.40		
Floor Price				0.075	2.664
Ceiling Price				0.235	8.343

Table 1.1-1
Comparison of 2004 and 2005 Illustrative Rates, Tolls and Charges

Service Type	Forecast 2005 Volume (10^6m^3)	2004 Rates ($\$/10^3m^3$)	2005 Rates ($\$/10^3m^3$)	Rate Variance [2004 - 2005] ($\$/10^3m^3$)	Revenue Using 2004 Rates ($Millions)	Revenue Using 2005 Rates ($Millions)	Revenue Variance [2004 - 2005] ($Millions)
FT-R[1]	82,271	188.41	167.52	20.89	509.3	452.8	56.5
FT-D	75,640	188.41	167.52	20.89	468.2	416.4	51.8
FT-A	10,557	0.57	0.50	0.07	6.0	5.3	0.7
FT-RN[2]	696	121.92	229.31	(107.40)	2.8	5.2	(2.5)
FT-P[2]	3,916	176.03	171.70	4.33	22.6	22.1	0.6
LRS[2]	6,733	193.14	195.87	(2.73)	42.7	43.3	(0.6)
LRS-2[3]	381	50,000/month	50,000/month	-	0.8	0.7	0.0
LRS-3[3]	515	188.71	192.37	(3.65)	3.2	3.3	(0.1)
STFT[2]	-	-	-	-	-	-	-
FT-DW[2]	-	-	-	-	-	-	-
IT-R[2]	21,306	6.49	5.80	0.69	138.3	123.6	14.7
IT-D[5]	10,715	6.81	6.05	0.76	73.0	64.8	8.1
FCS	n/a	n/a	n/a	n/a	5.4	4.9	0.5
CO_2[2]	n/a	n/a	n/a	n/a	15.8	15.4	0.4
PT[4]	n/a	n/a	n/a	n/a	-	0.9	(0.9)
Other Service	n/a	n/a	n/a	n/a	0.3	1.1	(0.8)

Revenue Variance (Overcollection) [6]		128.4
Total Revenue Collected [6]	1,160.0	
Revenue Requirement	1,160.0	
Revenue Over Collection	0.0	

1 Rate quoted is a volume weighted average for a three year contract term
2 Rate quoted is volume weighted average
3 Revenue quoted includes NGTL shareholder contribution
4 New service only forecasted in 2005.
5 Forecast quantity is net of Alternate Access
6 Revenue numbers have more than the one significant digit that is reported (variance in total is due to rounding)

TABLE 1.1-2 ILLUSTRATIVE 2005 RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for the applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $167.52/10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for the applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D	FT-D Demand Rate per month $167.52/10^3m^3$
4. Rate Schedule STFT	STFT Bid Price Minimum bid of 135% of FT-D Demand Rate
5. Rate Schedule FT-DW	FT-DW Demand Rate per month $293.16/10^3m^3$
6. Rate Schedule FT-A	FT-A Commodity Rate $0.50/10^3m^3$
7. Rate Schedule FT-P	Refer to Attachment "2" for the applicable FT-P Demand Rate per month
8. Rate Schedule LRS	Contract Term — Effective LRS Rate ($\$/10^3m^3$/day) 1-5 years — 9.50 6-10 years — 7.94 15 years — 7.12 20 years — 6.32
9. Rate Schedule LRS-2	LRS-2 Rate per month $50,000
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month $192.37/10^3m^3$
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point
12. Rate Schedule IT-D	IT-D Rate $6.05/10^3m^3$
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
14. Rate Schedule PT	Schedule No — PT Rate — PT Gas Rate 9004-01001-0 — $ 1,500.00/day — 50 10^3m^3/d 9004-01002-0 — $ 35.00/day — 3 10^3m^3/d
15. Rate Schedule OS	Schedule No. — Charge 2003-004522-2 — $ 83,333.00 / month 2003-034359-2 — $ 899.00 / month 2004-158284-1 — $ 220.00 / month 2005-187605-1 — $ 233.00 / month 2005-187603-1 — $ 3,638.00 / month 2004-158280-2 — $ 860.00 / month 2005-186989-1 — $ 1,562.00 / month 2005-187604-1 — $ 83.00 / month 2005-186998-1 — $ 622.00 / month 2005-187756-1 — $ 159.00 / month 2004-168619-1 — $ 437.00 / month 2005-186993-1 — $ 307.00 / month
16. Rate Schedule CO_2	Tier — CO_2 Rate ($\$/10^3m^3$) 1 — 603.39 2 — 461.42 3 — 319.44

TABLE 1.1-2 ATTACHMENT 1

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($\$/10^3m^3$)	FT-RN Demand Rate per Month ($\$/10^3m^3$)	IT-R Rate per Day ($\$/10^3m^3$)
1699	12 MILE COULEE	123.68	136.05	4.67
1337	ABEE	253.95	279.35	9.59
1631	ACADIA EAST	112.46	123.71	4.25
1613	ACADIA NORTH	113.05	124.36	4.27
1424	ACADIA VALLEY	160.61	176.67	6.07
3880	AECO INTERCONNECTION	81.10	89.21	3.06
1526	AKUINU RIVER	253.95	279.35	9.59
1681	AKUINU RIVER W.	253.95	279.35	9.59
1800	AKUINU RVR W.#2	253.95	279.35	9.59
2000	ALBERTA-B.C. BDR (CHART ACCOUNTING)	81.10	89.21	3.06
3868	ALBERTA-MONTANA BORDER INTERCONNECT	105.00	115.50	3.97
2109	ALDER FLATS	92.28	101.51	3.49
2291	ALDER FLATS #2	92.41	101.65	3.49
2200	ALDER FLATS S.	90.56	99.62	3.42
1075	ALDERSON	85.05	93.56	3.21
1208	ALDERSON NORTH	84.45	92.90	3.19
1103	ALDERSON SOUTH	85.09	93.60	3.21
5026	ALGAR LAKE	253.95	279.35	9.59
1851	AMISK SOUTH	231.48	254.63	8.75
1469	ANDREW	162.92	179.21	6.16
1573	ANSELL	125.82	138.40	4.75
2136	ANTE CREEK S.	253.95	279.35	9.59
1567	ARMENA	253.95	279.35	9.59
1770	ARMSTRONG LAKE	253.95	279.35	9.59
2708	ASSUMPTION	253.95	279.35	9.59
2734	ASSUMPTION #2	253.95	279.35	9.59
1326	ATHABASCA	245.41	269.95	9.27
1368	ATHABASCA EAST	235.27	258.80	8.89
1009	ATLEE-BUFFALO	81.10	89.21	3.06
1116	ATLEE-BUFFALO E	81.10	89.21	3.06
1098	ATLEE-BUFFALO S	81.10	89.21	3.06
1297	ATMORE	217.15	238.87	8.20
3858	ATMORE INTERCONNECTION	217.15	238.87	8.20
1792	ATUSIS CREEK E	81.10	89.21	3.06
3489	ATUSIS CREEK SL	81.10	89.21	3.06
1275	BADGER EAST	81.10	89.21	3.06
1649	BADGER NORTH	94.13	103.54	3.56
1782	BAILEY'S BOTTOM	188.74	207.61	7.13
2744	BALLATER #2	253.95	279.35	9.59
1100	BANTRY	81.10	89.21	3.06
1296	BANTRY N.E.	81.10	89.21	3.06
1181	BANTRY N.W.	81.10	89.21	3.06

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10³m³)	FT-RN Demand Rate per Month ($/10³m³)	IT-R Rate per Day ($/10³m³)
1122	BANTRY NORTH	81.10	89.21	3.06
1398	BAPTISTE	251.21	276.33	9.49
1339	BAPTISTE SOUTH	253.95	279.35	9.59
1497	BARICH	253.95	279.35	9.59
1329	BASHAW	190.99	210.09	7.22
1393	BASHAW B	190.86	209.95	7.21
1330	BASSANO SOUTH	90.52	99.57	3.42
1794	BASSANO SOUTH 2	90.64	99.70	3.42
2761	BASSET LAKE	253.95	279.35	9.59
2085	BASSET LAKE S.	253.95	279.35	9.59
2066	BASSET LAKE W.	253.95	279.35	9.59
1197	BAXTER LAKE	253.95	279.35	9.59
1334	BAXTER LAKE B	253.95	279.35	9.59
1382	BAXTER LAKE NW	253.95	279.35	9.59
1231	BAXTER LAKE S.	253.95	279.35	9.59
1198	BAXTER LAKE W.	253.95	279.35	9.59
2143	BAY TREE	253.95	279.35	9.59
2222	BEAR CANYON W.	223.10	245.41	8.43
2132	BEAR RIVER	253.95	279.35	9.59
1459	BEAUVALLON	253.95	279.35	9.59
1089	BELLIS	171.32	188.45	6.47
1675	BELLIS SOUTH	169.12	186.03	6.39
2043	BELLOY	231.78	254.96	8.76
2105	BELLOY WEST	196.07	215.68	7.41
1720	BELTZ LAKE	133.28	146.61	5.04
1264	BENALTO WEST	123.02	135.32	4.65
2177	BENBOW SOUTH	166.48	183.13	6.29
1274	BENTON WEST	99.84	109.82	3.77
1604	BERRY CREEK S.	110.85	121.94	4.19
1085	BERRY-CAROLSIDE	81.10	89.21	3.06
1157	BIG BEND	253.95	279.35	9.59
1225	BIG BEND EAST	253.95	279.35	9.59
2175	BIG PRAIRIE	253.95	279.35	9.59
1835	BIGKNIFE CREEK	114.18	125.60	4.31
2176	BIGORAY RIVER	141.07	155.18	5.33
1002	BINDLOSS N. #1	81.10	89.21	3.06
1001	BINDLOSS SOUTH	81.10	89.21	3.06
1474	BINDLOSS WEST	151.15	166.27	5.71
2256	BISON LAKE	253.95	279.35	9.59
3446	BITTERN LAKE SL	253.95	279.35	9.59
1616	BLOOD IND CK E.	86.22	94.84	3.26
1505	BLOOD INDIAN CK	81.10	89.21	3.06
1779	BLOOR LAKE	185.84	204.42	7.02
1511	BLUE JAY	253.95	279.35	9.59
2704	BLUE RAPIDS	98.13	107.94	3.71
3471	BLUE RIDGE E SL	184.11	202.52	6.96

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/$10^3m^3$)	FT-RN Demand Rate per Month ($/$10^3m^3$)	IT-R Rate per Day ($/$10^3m^3$)
2119	BLUEBERRY HILL	253.95	279.35	9.59
1242	BODO WEST	165.83	182.41	6.27
1590	BOHN LAKE	253.95	279.35	9.59
5012	BOIVIN CREEK	253.95	279.35	9.59
1227	BOLLOQUE	253.95	279.35	9.59
1778	BOLLOQUE #2	253.95	279.35	9.59
1290	BOLLOQUE SOUTH	253.95	279.35	9.59
1401	BONAR WEST	81.10	89.21	3.06
1796	BONNIE GLEN	158.57	174.43	5.99
1660	BONNYVILLE	253.95	279.35	9.59
2709	BOOTIS HILL	253.95	279.35	9.59
2117	BOTHA	247.73	272.50	9.36
2182	BOTHA EAST	253.95	279.35	9.59
2217	BOTHA WEST	253.95	279.35	9.59
2220	BOULDER CREEK	253.95	279.35	9.59
3001	BOUNDARY LAKE S	223.35	245.69	8.44
3002	BOUNDARY LK BDR	226.23	248.85	8.55
1318	BOWELL SOUTH	107.23	117.95	4.05
1849	BOWELL SOUTH #2	107.23	117.95	4.05
1216	BOWMANTON	110.37	121.41	4.17
1842	BOWMANTON EAST	100.11	110.12	3.78
1204	BOWMANTON SOUTH	91.57	100.73	3.46
1237	BOWMANTON WEST	178.99	196.89	6.76
2138	BOYER EAST	253.95	279.35	9.59
1703	BOYLE WEST	189.24	208.16	7.15
1096	BRAZEAU SOUTH	113.25	124.58	4.28
1947	BRAZEAU/EAST SUMMARY	117.74	129.51	4.45
1619	BRIGGS	100.92	111.01	3.81
2721	BROWNVALE NORTH	183.47	201.82	6.93
2364	BROWNVALE SALES	222.56	244.82	8.41
1168	BRUCE	118.35	130.19	4.47
1215	BRUCE NORTH	190.53	209.58	7.20
1409	BULLPOUND	105.58	116.14	3.99
1350	BULLPOUND SOUTH	177.94	195.73	6.72
1555	BULLSHEAD	145.40	159.94	5.49
6004	BURNT PINE	253.95	279.35	9.59
2118	BURNT RIVER	194.08	213.49	7.33
2032	BURNT TIMBER	85.99	94.59	3.25
2181	BUTTE	81.10	89.21	3.06
1561	BYEMOOR	137.30	151.03	5.19
1725	CADOGAN	253.95	279.35	9.59
2221	CADOTTE RIVER	253.95	279.35	9.59
2738	CALAIS	174.94	192.43	6.61
1373	CALLING LAKE	253.95	279.35	9.59
6019	CALLING LAKE	253.95	279.35	9.59
1522	CALLING LAKE E.	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/$10^3m^3$)	FT-RN Demand Rate per Month ($/$10^3m^3$)	IT-R Rate per Day ($/$10^3m^3$)
1443	CALLING LAKE W.	191.35	210.49	7.23
1676	CALLING LK N.	216.65	238.32	8.19
1387	CALLING LK S.	223.82	246.20	8.46
2743	CALLUM CREEK	81.10	89.21	3.06
1651	CAMROSE CREEK	253.95	279.35	9.59
1805	CANOE LAKE	253.95	279.35	9.59
3866	CARBON INTERCONNECTION	81.10	89.21	3.06
1622	CARBON WEST	81.10	89.21	3.06
1692	CARIBOU LAKE	253.95	279.35	9.59
3893	CARROT CREEK INTERCONNECTION	113.58	124.94	4.29
1840	CARSELAND RECEIPT	81.10	89.21	3.06
2018	CARSON CREEK	190.44	209.48	7.20
2188	CARSON CREEK E.	227.33	250.06	8.59
3330	CARSTAIRS INTERCONNECTION	81.10	89.21	3.06
1491	CASLAN	253.95	279.35	9.59
1492	CASLAN EAST	253.95	279.35	9.59
1315	CASSILS	97.46	107.21	3.68
1397	CASTOR	147.76	162.54	5.58
2727	CATTAIL LAKE	163.59	179.95	6.18
1737	CAVALIER	116.87	128.56	4.42
1228	CAVENDISH SOUTH	81.10	89.21	3.06
2768	CECILIA	132.64	145.90	5.01
1025	CESSFORD EAST	81.10	89.21	3.06
1152	CESSFORD N.E.	81.10	89.21	3.06
1145	CESSFORD NORTH	81.10	89.21	3.06
1312	CESSFORD SOUTH	81.10	89.21	3.06
1086	CESSFORD W GAGE	81.10	89.21	3.06
1004	CESSFORD WARDLO	81.10	89.21	3.06
1012	CESSFORD WEST	81.10	89.21	3.06
1060	CESSFORD-BUR #2	85.24	93.76	3.22
1027	CESSFORD-BURF W	97.85	107.64	3.70
3907	CHANCELLOR INTERCONNECTION	81.10	89.21	3.06
1196	CHAUVIN	253.95	279.35	9.59
1666	CHEECHAM	253.95	279.35	9.59
1708	CHELSEA CREEK	253.95	279.35	9.59
1680	CHERRY GROVE E.	253.95	279.35	9.59
2705	CHESTER CREEK	253.95	279.35	9.59
2286	CHICKADEE CK W.	253.95	279.35	9.59
1034	CHIGWELL	184.16	202.58	6.96
1040	CHIGWELL EAST	175.20	192.72	6.62
2108	CHINCHAGA	234.83	258.31	8.87
2266	CHINCHAGA WEST	253.95	279.35	9.59
1221	CHINOOK-CEREAL	128.17	140.99	4.84
5409	CHIP LAKE	113.69	125.06	4.30
3885	CHIP LAKE JCT	113.58	124.94	4.29
1609	CHISHOLM MILL W	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10³m³)	FT-RN Demand Rate per Month ($/10³m³)	IT-R Rate per Day ($/10³m³)
1434	CHISHOLM MILLS	253.95	279.35	9.59
1322	CHOICE	253.95	279.35	9.59
1323	CHOICE B	253.95	279.35	9.59
1712	CHRISTINA LAKE	253.95	279.35	9.59
1679	CHUMP LAKE	253.95	279.35	9.59
1535	CLANDONALD	253.95	279.35	9.59
2070	CLARK LAKE	148.15	162.97	5.60
2063	CLEAR HILLS	228.10	250.91	8.62
2250	CLEAR HILLS N.	195.32	214.85	7.38
2764	CLEAR PRAIRIE	253.95	279.35	9.59
3008	CLEARDALE	249.91	274.90	9.44
1454	CLYDE	253.95	279.35	9.59
1803	CLYDE NORTH	253.95	279.35	9.59
6007	CLYDEN	253.95	279.35	9.59
3883	COALDALE JCT	81.10	89.21	3.06
5402	COALDALE S. B	102.15	112.37	3.86
3884	COALDALE S. JCT	81.10	89.21	3.06
1612	COATES LAKE	209.30	230.23	7.91
2735	CODESA	240.59	264.65	9.09
2152	CODNER	117.91	129.70	4.45
1417	COLD LAKE BDR	253.95	279.35	9.59
2003	COLEMAN	81.10	89.21	3.06
3052	COLEMAN SALES	81.10	89.21	3.06
1624	CONKLIN	253.95	279.35	9.59
1634	CONKLIN WEST	253.95	279.35	9.59
3904	CONKLIN WEST INTERCHANGE INTERCONNECTION	253.95	279.35	9.59
1713	CONN LAKE	253.95	279.35	9.59
1635	CONTRACOSTA E.	198.60	218.46	7.50
1614	CONTRACOSTA LK	148.60	163.46	5.61
2736	COPTON CREEK	215.15	236.67	8.13
1763	CORNER LAKE #2	253.95	279.35	9.59
6010	CORRIGAL LAKE	253.95	279.35	9.59
1697	CORRIGALL LAKE	253.95	279.35	9.59
1667	COTTONWOOD CRK	253.95	279.35	9.59
1028	COUNTESS	81.10	89.21	3.06
1015	COUNTESS MAKEPE	84.58	93.04	3.20
2296	COUNTESS S. #2	81.10	89.21	3.06
1287	COUNTESS WEST	136.76	150.44	5.17
1963	COUSINS B&C SALES	118.02	129.82	4.46
1433	COUSINS WEST	118.35	130.19	4.47
1112	CRAIGEND EAST	235.74	259.31	8.91
1320	CRAIGEND NORTH	253.95	279.35	9.59
1148	CRAIGEND SOUTH	253.95	279.35	9.59
1541	CRAIGMYLE	224.98	247.48	8.50
1583	CRAIGMYLE EAST	253.95	279.35	9.59
1686	CRAMMOND	81.10	89.21	3.06

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
2749	CRANBERRY LK #2	253.95	279.35	9.59
3105	CRANBERRY LK SL	253.95	279.35	9.59
1701	CROOKED LK S.	155.92	171.51	5.89
2724	CROOKED LK W.	143.96	158.36	5.44
2008	CROSSFIELD	81.10	89.21	3.06
3897	CROSSFIELD EAST #2 INTERCONNECTION	81.10	89.21	3.06
2017	CROSSFIELD WEST	81.10	89.21	3.06
1773	CROW LAKE SOUTH	253.95	279.35	9.59
2731	CROWELL	253.95	279.35	9.59
2718	CULP #2	253.95	279.35	9.59
1807	CULP NORTH	253.95	279.35	9.59
1489	CUTBANK RIVER	216.11	237.72	8.17
2209	CYNTHIA #2	102.75	113.03	3.88
1738	DANCING LAKE	253.95	279.35	9.59
1279	DAPP EAST	253.95	279.35	9.59
2289	DARLING CREEK	253.95	279.35	9.59
1529	DAYSLAND	123.48	135.83	4.67
2233	DEBOLT	229.85	252.84	8.68
1760	DECRENE EAST	253.95	279.35	9.59
1646	DECRENE NORTH	253.95	279.35	9.59
3888	DEEP VALLEY CREEK EAST INTERCONNECTION	199.30	219.23	7.53
2244	DEEP VLLY CRK S	140.43	154.47	5.31
1539	DELIA	179.42	197.36	6.78
1476	DEMMITT	230.30	253.33	8.70
2717	DEMMITT #2	230.29	253.32	8.70
1734	DEVENISH SOUTH	253.95	279.35	9.59
1733	DEVENISH WEST	253.95	279.35	9.59
1793	DIAMOND CITY	128.44	141.28	4.85
1185	DISMAL CREEK	124.89	137.38	4.72
2210	DIXONVILLE N #2	193.44	212.78	7.31
2110	DIXONVILLE N.	250.55	275.61	9.47
2197	DOE CREEK	253.95	279.35	9.59
2712	DOE CREEK SOUTH	253.95	279.35	9.59
1147	DONALDA	217.53	239.28	8.22
1520	DONATVILLE	229.14	252.05	8.66
2139	DONNELLY	253.95	279.35	9.59
2254	DORIS CREEK N.	245.21	269.73	9.26
2297	DORIS CREEK S.	253.95	279.35	9.59
1236	DOROTHY	152.13	167.34	5.75
1818	DOWLING	90.87	99.96	3.43
2719	DREAU	245.39	269.93	9.27
1689	DROPOFF CREEK	253.95	279.35	9.59
5022	DUNKIRK RIVER	253.95	279.35	9.59
1220	DUNMORE	129.14	142.05	4.88
2044	DUNVEGAN	201.32	221.45	7.61
2716	DUNVEGAN W. #2	247.07	271.78	9.33

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($\$/10^3m^3$)	FT-RN Demand Rate per Month ($\$/10^3m^3$)	IT-R Rate per Day ($\$/10^3m^3$)
2084	DUNVEGAN WEST	247.07	271.78	9.33
3062	E. CALGARY B SL	81.10	89.21	3.06
2081	EAGLE HILL	121.04	133.14	4.57
2097	EAGLESHAM	171.89	189.08	6.49
2007	EAST CALGARY	81.10	89.21	3.06
1568	EDBERG	213.40	234.74	8.06
1265	EDGERTON	253.95	279.35	9.59
1266	EDGERTON WEST	253.95	279.35	9.59
1064	EDSON	121.26	133.39	4.58
1213	EDWAND	190.36	209.40	7.19
1467	EDWAND SOUTH	181.46	199.61	6.86
2760	EKWAN	253.95	279.35	9.59
1715	ELINOR LAKE	253.95	279.35	9.59
1742	ELINOR LAKE E.	253.31	278.64	9.57
1558	ELK RIVER SOUTH	113.91	125.30	4.30
1615	ELMWORTH HIGH	172.84	190.12	6.53
1862	ELNORA EAST #2	211.05	232.16	7.97
1958	EMPRESS BORDER	81.10	89.21	3.06
1024	ENCHANT	100.70	110.77	3.80
1507	ENDIANG	92.74	102.01	3.50
1074	EQUITY	107.79	118.57	4.07
1359	EQUITY B	123.15	135.47	4.65
1586	EQUITY EAST	125.86	138.45	4.76
1232	ERSKINE NORTH	168.69	185.56	6.37
1746	ESTRIDGE LAKE	253.95	279.35	9.59
2049	ETA LAKE	118.49	130.34	4.48
1547	ETZIKOM A	239.06	262.97	9.03
1548	ETZIKOM B	239.04	262.94	9.03
1557	ETZIKOM D	239.29	263.22	9.04
1677	FAIRYDELL CREEK	253.95	279.35	9.59
3112	FALHER SALES	253.95	279.35	9.59
2729	FARIA	253.95	279.35	9.59
1375	FAWCETT RIVER	253.95	279.35	9.59
1389	FAWCETT RIVER E	253.95	279.35	9.59
1753	FAWCETT RVR N.	253.95	279.35	9.59
1659	FERINTOSH WEST	253.95	279.35	9.59
2016	FERRIER	118.76	130.64	4.49
1101	FERRIER NORTH	113.65	125.02	4.29
2115	FERRIER SOUTH A	118.83	130.71	4.49
1111	FERRIER SOUTH B	123.74	136.11	4.68
1087	FIGURE LAKE	221.35	243.49	8.36
1300	FITZALLAN SOUTH	185.28	203.81	7.00
1095	FLAT LAKE	249.94	274.93	9.44
1302	FLAT LAKE NORTH	253.95	279.35	9.59
1394	FLATBUSH	253.95	279.35	9.59
1632	FOISY	204.63	225.09	7.73

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
2251	FONTAS RIVER	253.95	279.35	9.59
3304	FORESTBURG SLS	102.63	112.89	3.88
1376	FORSHEE	100.53	110.58	3.80
1602	FORT KENT	253.95	279.35	9.59
2199	FOULWATER CREEK	253.95	279.35	9.59
2103	FOURTH CREEK	253.95	279.35	9.59
2178	FOURTH CREEK S.	253.95	279.35	9.59
2198	FOURTH CREEK W.	247.54	272.29	9.35
2268	FRAKES FLATS	178.12	195.93	6.73
2079	GARRINGTON EAST	115.00	126.50	4.34
1623	GATINE	81.10	89.21	3.06
1435	GEM SOUTH	81.10	89.21	3.06
1490	GEM WEST	81.10	89.21	3.06
1073	GHOSTPINE	90.85	99.94	3.43
1617	GHOSTPINE 'B'	93.96	103.36	3.55
1037	GILBY #2	110.94	122.03	4.19
1084	GILBY SOUTH PAC	110.93	122.02	4.19
2037	GILBY WEST	120.04	132.04	4.54
2722	GILMORE LAKE	192.13	211.34	7.26
3894	GILT EDGE WEST INTERCONNECTION	253.95	279.35	9.59
1480	GLEICHEN	167.76	184.54	6.34
1456	GLENDON	253.95	279.35	9.59
2290	GODS LAKE	253.95	279.35	9.59
2031	GOLD CREEK	157.37	173.11	5.95
1452	GOODFARE	211.20	232.32	7.98
1504	GOODRIDGE	253.95	279.35	9.59
1783	GOODRIDGE NORTH	253.95	279.35	9.59
1798	GOOSEQUILL	208.61	229.47	7.88
3886	GORDONDALE BORDER	215.43	236.97	8.14
1560	GOUGH LAKE	98.77	108.65	3.73
1448	GRACE CREEK	121.37	133.51	4.59
1482	GRAHAM	253.95	279.35	9.59
1352	GRAINGER	81.10	89.21	3.06
2129	GRANADA	141.17	155.29	5.33
3424	GRANDE CENTRE S	253.95	279.35	9.59
5005	GRANOR	253.95	279.35	9.59
1093	GREENCOURT	200.03	220.03	7.56
1267	GREGORY	91.18	100.30	3.44
1365	GREGORY N.E.	82.19	90.41	3.11
1259	GREGORY WEST	81.10	89.21	3.06
5025	GREW LAKE	253.95	279.35	9.59
5028	GREW LK EAST	253.95	279.35	9.59
1647	GRIST LAKE	253.95	279.35	9.59
2770	GRIZZLY	158.19	174.01	5.98
1538	HACKETT	239.58	263.54	9.05
1722	HACKETT WEST	252.38	277.62	9.54

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10³m³)	FT-RN Demand Rate per Month ($/10³m³)	IT-R Rate per Day ($/10³m³)
1576	HADDOCK	146.27	160.90	5.53
1589	HADDOCK NORTH	150.86	165.95	5.70
1636	HADDOCK SOUTH	173.65	191.02	6.56
2086	HAIG RIVER	253.95	279.35	9.59
2064	HAIG RIVER EAST	253.95	279.35	9.59
2127	HAIG RIVER N.	253.95	279.35	9.59
1230	HAIRY HILL	180.16	198.18	6.81
1391	HALKIRK	124.67	137.14	4.71
1834	HALKIRK NORTH#2	94.55	104.01	3.57
3915	HAMILTON LAKE SUMMARY	223.45	245.80	8.44
1291	HAMLIN	253.95	279.35	9.59
6003	HANGINGSTONE	253.95	279.35	9.59
1182	HANNA	93.58	102.94	3.54
1444	HARDISTY	226.84	249.52	8.57
1166	HARMATTAN-ELKTN	81.10	89.21	3.06
2145	HARO RIVER N.	253.95	279.35	9.59
2766	HARPER CREEK	190.27	209.30	7.19
1850	HARTELL SOUTH	81.10	89.21	3.06
1709	HASTINGS COULEE	154.62	170.08	5.84
1418	HATTIE LAKE N.	253.95	279.35	9.59
2126	HAY RIVER	253.95	279.35	9.59
2278	HAY RIVER SOUTH	253.95	279.35	9.59
1603	HAYS	182.91	201.20	6.91
2140	HEART RIVER	253.95	279.35	9.59
1439	HEISLER	105.00	115.50	3.97
1523	HELINA	253.95	279.35	9.59
2174	HENDERSON CK SE	243.59	267.95	9.20
2164	HENDERSON CREEK	239.30	263.23	9.04
1673	HERMIT LAKE	208.21	229.03	7.87
3611	HERMIT LAKE SLS	208.31	229.14	7.87
2059	HINES CREEK	253.95	279.35	9.59
2219	HINES CREEK W.	253.95	279.35	9.59
1161	HOLDEN	170.44	187.48	6.44
1528	HOOLE	253.95	279.35	9.59
1411	HORBURG	99.56	109.52	3.76
2047	HOTCHKISS	253.95	279.35	9.59
2065	HOTCHKISS EAST	253.95	279.35	9.59
2094	HOTCHKISS NE B	253.95	279.35	9.59
2095	HOTCHKISS NE C	253.95	279.35	9.59
2054	HOTCHKISS NORTH	246.92	271.61	9.33
3920	HOUSE RIVER INTERCONNECTION	253.95	279.35	9.59
2169	HOWARD CREEK E.	253.95	279.35	9.59
1207	HUDSON	155.67	171.24	5.88
1413	HUDSON WEST	129.14	142.05	4.88
1854	HUGHENDEN EAST	199.85	219.84	7.55
1859	HUMMOCK LAKE	102.56	112.82	3.87

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
2277	HUNT CREEK	253.95	279.35	9.59
2751	HUNT CREEK #2	253.95	279.35	9.59
1436	HUSSAR NORTH	81.10	89.21	3.06
1016	HUSSAR-CHANCELL	81.10	89.21	3.06
1142	HUXLEY	112.95	124.25	4.27
1591	HUXLEY EAST	223.82	246.20	8.46
1241	HYLO	253.95	279.35	9.59
1357	HYLO SOUTH	253.95	279.35	9.59
1479	HYTHE	219.20	241.12	8.28
1277	IDDESLEIGH S.	84.67	93.14	3.20
1678	INDIAN LAKE	139.56	153.52	5.27
1717	INDIAN LAKE #2	139.00	152.90	5.25
3857	INLAND INTERCONNECTION	148.72	163.59	5.62
1685	IPIATIK LAKE	253.95	279.35	9.59
1441	IRISH	253.95	279.35	9.59
1593	IRON SPRINGS	81.10	89.21	3.06
1569	IROQUOIS CREEK	169.90	186.89	6.42
1201	IRVINE	147.61	162.37	5.58
1407	ISLAND LAKE	212.89	234.18	8.04
1700	ISLAND LAKE #2	212.82	234.10	8.04
1694	JACKFISH CREEK	253.95	279.35	9.59
2723	JACKPOT CREEK	253.95	279.35	9.59
2146	JACKSON CREEK	86.17	94.79	3.26
3860	JANUARY CREEK INTERCONNECTION	128.31	141.14	4.85
1163	JARROW	251.51	276.66	9.50
1159	JARROW SOUTH	236.45	260.10	8.93
1281	JARROW WEST	253.95	279.35	9.59
1143	JENNER EAST	81.10	89.21	3.06
1099	JENNER WEST	81.10	89.21	3.06
1385	JENNER WEST B	81.10	89.21	3.06
1167	JOFFRE	164.53	180.98	6.22
3864	JOFFRE #2 AND #3 SALES INTERCONNECTION	111.13	122.24	4.20
2267	JONES LAKE	195.89	215.48	7.40
2279	JONES LAKE #2	196.07	215.68	7.41
2272	JONES LAKE EAST	212.55	233.81	8.03
2241	JONES LAKE N.	227.74	250.51	8.60
2087	JOSEPHINE	245.89	270.48	9.29
2022	JUDY CREEK	245.66	270.23	9.28
2036	JUMPING POUND W	81.10	89.21	3.06
1811	KAKWA	195.75	215.33	7.40
1462	KARR	154.03	169.43	5.82
2013	KAYBOB	169.77	186.75	6.41
2027	KAYBOB 11-36	167.78	184.56	6.34
2020	KAYBOB SOUTH	156.09	171.70	5.90
2035	KAYBOB SOUTH #3	133.44	146.78	5.04
2053	KEG RIVER	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
2068	KEG RIVER EAST	253.95	279.35	9.59
2216	KEG RIVER NORTH	253.95	279.35	9.59
1517	KEHIWIN	253.95	279.35	9.59
1224	KEHO LAKE	81.10	89.21	3.06
1775	KEHO LAKE NORTH	104.70	115.17	3.96
2748	KEMP RIVER	253.95	279.35	9.59
1483	KENT	253.95	279.35	9.59
2739	KEPPLER CREEK	253.95	279.35	9.59
1845	KERSEY	81.10	89.21	3.06
1627	KETTLE RIVER	253.95	279.35	9.59
2288	KIDNEY LAKE	253.95	279.35	9.59
1608	KIKINO	225.21	247.73	8.51
1772	KIKINO NORTH	198.73	218.60	7.51
1162	KILLAM	253.95	279.35	9.59
1298	KILLAM NORTH	253.95	279.35	9.59
1682	KINOSIS	253.95	279.35	9.59
1446	KIRBY	253.95	279.35	9.59
1727	KIRBY NORTH #2	253.95	279.35	9.59
2759	KSITUAN R E #2	253.95	279.35	9.59
2134	KSITUAN RIVER	235.42	258.96	8.89
1721	LAC LA BICHE	253.95	279.35	9.59
1860	LACOMBE LAKE	93.79	103.17	3.54
1718	LACOREY	253.95	279.35	9.59
2287	LAFOND CREEK	253.95	279.35	9.59
1210	LAKE NEWELL E.	129.40	142.34	4.89
1562	LAKEVIEW LAKE	97.68	107.45	3.69
1828	LAKEVIEW LAKE #2	91.44	100.58	3.45
2737	LALBY CREEK	253.95	279.35	9.59
1767	LAMERTON	253.95	279.35	9.59
1206	LANFINE	103.26	113.59	3.90
1564	LARKSPUR	253.95	279.35	9.59
2223	LAST LAKE	202.46	222.71	7.65
2151	LASTHILL CREEK	88.74	97.61	3.35
2259	LATHROP CREEK	232.44	255.68	8.78
1132	LAVOY	178.82	196.70	6.76
1695	LAWRENCE LAKE N	253.95	279.35	9.59
2040	LEAFLAND	160.07	176.08	6.05
1833	LEE LAKE	171.70	188.87	6.49
2179	LEEDALE	92.35	101.59	3.49
6016	LEISMER #1	253.95	279.35	9.59
6017	LEISMER #2	253.95	279.35	9.59
3605	LEMING LAKE SLS	253.95	279.35	9.59
2249	LENNARD CREEK	253.95	279.35	9.59
1272	LEO	81.10	89.21	3.06
5003	LIEGE	253.95	279.35	9.59
1536	LINARIA	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1857	LINDEN	81.10	89.21	3.06
1494	LITTLE SUNDANCE	123.37	135.71	4.66
2111	LOBSTICK	112.64	123.90	4.26
1465	LONE BUTTE	164.76	181.24	6.23
1069	LONE PINE CREEK	86.64	95.30	3.27
1139	LONE PINE SOUTH	81.12	89.23	3.06
1768	LONESOME LAKE	95.38	104.92	3.60
1630	LONG LAKE WEST	253.95	279.35	9.59
1366	LOUISIANA LAKE	123.03	135.33	4.65
1496	LOUSANA	206.96	227.66	7.82
2128	LOVET CREEK	253.95	279.35	9.59
1386	LUCKY LAKE	253.95	279.35	9.59
3058	LUNDBRECK-COWLE	81.10	89.21	3.06
5021	MACKAY RIVER	253.95	279.35	9.59
2702	MAHASKA	184.23	202.65	6.96
2700	MAHASKA WEST	152.45	167.70	5.76
1229	MAJESTIC	111.21	122.33	4.20
1419	MAKEPEACE NORTH	91.14	100.25	3.44
1719	MANATOKEN LAKE	253.95	279.35	9.59
2720	MANIR	228.66	251.53	8.64
1273	MAPLE GLEN	82.11	90.32	3.10
1572	MARLBORO	170.79	187.87	6.45
1663	MARLBORO EAST	170.98	188.08	6.46
2713	MARLOW CREEK	253.95	279.35	9.59
2762	MARSH HD CK W#2	135.95	149.55	5.14
2750	MARSH HEAD CK WEST	135.93	149.52	5.14
2228	MARSH HEAD CRK	152.99	168.29	5.78
1091	MARTEN HILLS	253.95	279.35	9.59
1672	MARTEN HILLS N.	253.95	279.35	9.59
1097	MARTEN HILLS S.	253.95	279.35	9.59
1769	MASTIN LAKE	243.45	267.80	9.20
1270	MATZHIWIN EAST	114.57	126.03	4.33
1284	MATZHIWIN N.E.	86.25	94.88	3.26
1379	MATZHIWIN SOUTH	81.10	89.21	3.06
1150	MATZHIWIN WEST	81.10	89.21	3.06
1514	MAUGHAN	253.95	279.35	9.59
1633	MAY HILL	253.95	279.35	9.59
2706	MCLEAN CREEK	253.95	279.35	9.59
2144	MCLENNAN	253.95	279.35	9.59
2710	MCMILLAN LAKE	253.95	279.35	9.59
6404	MCNEILL BORDER	81.10	89.21	3.06
1704	MEADOW CREEK	253.95	279.35	9.59
1707	MEADOW CREEK E.	253.95	279.35	9.59
1705	MEADOW CRK WEST	253.95	279.35	9.59
1338	MEANOOK	253.95	279.35	9.59
1017	MED HAT N. #1	81.10	89.21	3.06

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1184	MED HAT N. ARCO	81.10	89.21	3.06
1325	MED HAT N. F	81.10	89.21	3.06
1205	MED HAT N.W.	81.10	89.21	3.06
1018	MED HAT S. #1	81.10	89.21	3.06
1043	MED HAT S. #2	81.10	89.21	3.06
1128	MED HAT S. #4	81.10	89.21	3.06
1172	MED HAT WEST	81.10	89.21	3.06
1186	MEDICINE HAT E.	89.93	98.92	3.40
1214	MEDICINE RVR A	229.35	252.29	8.67
1645	METISKOW NORTH	184.04	202.44	6.95
1362	MEYER	253.95	279.35	9.59
1508	MICHICHI	161.33	177.46	6.10
1146	MIKWAN	152.35	167.59	5.76
1427	MIKWAN EAST	244.69	269.16	9.24
1144	MIKWAN NORTH	115.05	126.56	4.35
2237	MILLERS LAKE	131.16	144.28	4.96
1524	MILLS	253.41	278.75	9.57
1578	MILO	91.46	100.61	3.46
1396	MINBURN	253.95	279.35	9.59
2149	MINNEHIK-BK L B	110.62	121.68	4.18
2010	MINNEHIK-BK LK	109.99	120.99	4.16
1693	MINNOW LAKE	168.97	185.87	6.38
1658	MIQUELON LAKE	253.95	279.35	9.59
2273	MIRAGE	235.54	259.09	8.90
1500	MIRROR	176.78	194.46	6.68
1090	MITSUE	253.95	279.35	9.59
3889	MITSUE INTERCONNECTION	253.95	279.35	9.59
1457	MITSUE SOUTH	253.95	279.35	9.59
3863	MONARCH INTERCONNECTION	81.10	89.21	3.06
1605	MONITOR CREEK	115.96	127.56	4.38
1771	MONITOR CREEK W	178.18	196.00	6.73
1222	MONITOR SOUTH	121.86	134.05	4.60
1292	MONS LAKE	253.95	279.35	9.59
1355	MONS LAKE EAST	253.95	279.35	9.59
1823	MOOSE PORTAGE	195.21	214.73	7.38
1484	MOOSELAKE RIVER	253.95	279.35	9.59
1460	MORECAMBE	253.95	279.35	9.59
1458	MORRIN	160.62	176.68	6.07
1781	MOSS LAKE	253.95	279.35	9.59
1802	MOSS LAKE NORTH	217.32	239.05	8.21
1641	MOUNT VALLEY	214.43	235.87	8.10
2732	MOUNTAIN LAKE	213.44	234.78	8.06
1774	MUNSON	217.95	239.75	8.23
1551	MURRAY LAKE	184.08	202.49	6.95
1843	MURRAY LAKE NORTH	178.89	196.78	6.76
2236	MUSKEG CREEK	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1785	MUSKWA RIVER	253.95	279.35	9.59
2711	MUSREAU LAKE	229.51	252.46	8.67
1730	MYRNAM	253.95	279.35	9.59
2745	NARRAWAY RIVER	236.36	260.00	8.93
3009	NEPTUNE	223.46	245.81	8.44
1276	NESTOW	231.78	254.96	8.76
1316	NETOOK	253.95	279.35	9.59
1020	NEVIS NORTH	134.74	148.21	5.09
1019	NEVIS SOUTH	130.05	143.06	4.91
1502	NEWBROOK	253.95	279.35	9.59
1140	NEWELL NORTH	81.10	89.21	3.06
1747	NIGHTINGALE	81.10	89.21	3.06
2242	NIOBE CREEK	213.35	234.69	8.06
1194	NIPISI	253.95	279.35	9.59
1776	NISBET LAKE	253.95	279.35	9.59
2071	NITON	125.38	137.92	4.74
2172	NITON NORTH	137.30	151.03	5.19
3368	NOEL LAKE SALES	201.78	221.96	7.62
2714	NOEL LAKE SOUTH	191.89	211.08	7.25
6006	NORTH DUNCAN	253.95	279.35	9.59
6009	NORTH HANGINGSTONE	253.95	279.35	9.59
3454	NORTH PENHOLD SALES	89.50	98.45	3.38
6008	NORTH THORNBURY	253.95	279.35	9.59
2767	NOSE MOUNTAIN	226.50	249.15	8.56
2192	NOTIKEWIN RIVER	253.95	279.35	9.59
2218	NOTIKEWIN RVR N	239.76	263.74	9.06
1824	OBED CREEK	155.46	171.01	5.87
1829	OBED NORTH	126.59	139.25	4.78
1053	OLDS	102.53	112.78	3.87
1545	OPAL	253.95	279.35	9.59
1814	ORLOFF LAKE	253.95	279.35	9.59
2726	ORTON	81.10	89.21	3.06
1716	OSBORNE LAKE	253.95	279.35	9.59
1812	OSLAND LAKE	239.09	263.00	9.03
1587	OVERLEA	253.95	279.35	9.59
1817	OWL LAKE	241.55	265.71	9.13
2728	OWL LAKE SOUTH	237.12	260.83	8.96
2742	OWL LAKE STH #2	236.89	260.58	8.95
2746	OWL LAKE STH #3	236.89	260.58	8.95
1495	OWLSEYE	253.95	279.35	9.59
1007	OYEN	109.08	119.99	4.12
1058	OYEN NORTH	81.75	89.93	3.09
2098	PADDLE PRAIR S.	253.95	279.35	9.59
2093	PADDLE PRAIRIE	253.95	279.35	9.59
1307	PADDLE RIVER	211.65	232.82	8.00
1852	PAKAN LAKE	203.03	223.33	7.67

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1728	PARADISE VALLEY	253.95	279.35	9.59
1853	PARKER CREEK	253.95	279.35	9.59
1665	PARSONS LAKE	253.95	279.35	9.59
2089	PASS CREEK	146.43	161.07	5.53
2168	PASS CREEK WEST	140.59	154.65	5.31
2260	PASTECHO RIVER	253.95	279.35	9.59
1278	PATRICIA	81.10	89.21	3.06
1289	PATRICIA WEST	90.33	99.36	3.41
3804	PEMBINA INTERCONNECTION	96.46	106.11	3.64
2185	PEMBINA WEST	107.39	118.13	4.06
1180	PENHOLD	86.40	95.04	3.26
1607	PENHOLD WEST	121.62	133.78	4.60
2280	PETE LAKE	241.21	265.33	9.11
2247	PETE LAKE SOUTH	192.93	212.22	7.29
1714	PICHE LAKE	253.95	279.35	9.59
1610	PICTURE BUTTE	173.15	190.47	6.54
2046	PIONEER	116.52	128.17	4.40
2088	PIONEER EAST	152.99	168.29	5.78
1739	PIPER CREEK	118.71	130.58	4.49
1797	PITLO	253.95	279.35	9.59
1110	PLAIN LAKE	226.12	248.73	8.54
1710	PLEASANT WEST	253.95	279.35	9.59
1858	POE	115.62	127.18	4.37
2173	POISON CREEK	160.36	176.40	6.06
3879	PRIDDIS INTERCONNECTION	81.10	89.21	3.06
1246	PRINCESS EAST	81.10	89.21	3.06
1327	PRINCESS SOUTH	81.10	89.21	3.06
1183	PRINCESS WEST	81.10	89.21	3.06
1010	PRINCESS-DENHAR	81.10	89.21	3.06
1022	PRINCESS-IDDESL	81.10	89.21	3.06
2153	PROGRESS	202.02	222.22	7.63
2191	PROGRESS EAST	208.03	228.83	7.86
1304	PROSPERITY	229.54	252.49	8.67
1211	PROVOST MONITOR	223.03	245.33	8.43
1003	PROVOST NORTH	132.84	146.12	5.02
1013	PROVOST SOUTH	143.52	157.87	5.42
1045	PROVOST WEST	197.26	216.99	7.45
1038	PROVOST-KESSLER	214.78	236.26	8.11
1601	QUEENSTOWN	185.36	203.90	7.00
2026	QUIRK CREEK	81.10	89.21	3.06
1741	RABBIT LAKE	253.95	279.35	9.59
2201	RAINBOW LAKE S.	253.95	279.35	9.59
1106	RAINIER	81.10	89.21	3.06
1380	RAINIER S.W.	87.34	96.07	3.30
1378	RAINIER SOUTH	115.71	127.28	4.37
1282	RALSTON	95.09	104.60	3.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1826	RALSTON SOUTH	83.75	92.13	3.16
2148	RAMBLING CREEK	253.95	279.35	9.59
2213	RAMBLING CRK E.	253.95	279.35	9.59
1164	RANFURLY	232.22	255.44	8.77
3911	RANFURLY INTERCONNECTION	232.25	255.48	8.77
1189	RANFURLY NORTH	161.57	177.73	6.10
1165	RANFURLY WEST	197.66	217.43	7.47
2211	RASPBERRY LAKE	205.99	226.59	7.78
2104	RAT CREEK	100.87	110.96	3.81
2265	RAT CREEK SOUTH	112.58	123.84	4.25
2252	RAT CREEK WEST	121.03	133.13	4.57
2193	RAY LAKE SOUTH	253.95	279.35	9.59
2166	RAY LAKE WEST	253.95	279.35	9.59
1209	REDCLIFF	125.63	138.19	4.75
1219	REDCLIFF SOUTH	107.59	118.35	4.07
1838	REDCLIFF STH #2	107.59	118.35	4.07
1346	REDCLIFF WEST	123.88	136.27	4.68
3438	REDWATER 'B' SL	253.95	279.35	9.59
3406	REDWATER SALES	253.95	279.35	9.59
1057	RETLAW	81.10	89.21	3.06
1218	RETLAW SOUTH	102.27	112.50	3.86
1392	RIBSTONE	253.95	279.35	9.59
1374	RICH LAKE	253.95	279.35	9.59
1135	RICINUS	99.19	109.11	3.75
1372	RICINUS SOUTH	97.88	107.67	3.70
1437	RICINUS WEST	103.75	114.13	3.92
1949	RIMBEY/WESTEROSE SUMMARY	108.01	118.81	4.08
3405	RIM-WEST SALES	108.01	118.81	4.08
1510	RIVERCOURSE	253.95	279.35	9.59
1499	ROBB	138.56	152.42	5.24
1336	ROCHESTER	253.95	279.35	9.59
1400	ROCK ISLAND LK	253.95	279.35	9.59
1820	ROCK ISLAND S2	253.95	279.35	9.59
1134	ROCKYFORD	81.10	89.21	3.06
2715	ROD LAKE	253.95	279.35	9.59
1468	ROSALIND	133.59	146.95	5.05
1579	ROSE LYNNE	81.10	89.21	3.06
1466	ROSEMARY	81.10	89.21	3.06
1461	ROSEMARY NORTH	81.10	89.21	3.06
2099	ROSEVEAR SOUTH	131.91	145.10	4.98
2725	ROSSBEAR LAKE	253.95	279.35	9.59
1706	ROURKE CRK EAST	253.95	279.35	9.59
1540	ROWLEY	156.57	172.23	5.92
1299	ROYAL PARK	154.52	169.97	5.84
1530	RUMSEY	157.10	172.81	5.94
1600	RUMSEY WEST	193.13	212.44	7.30

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($\$/10^3m^3$)	FT-RN Demand Rate per Month ($\$/10^3m^3$)	IT-R Rate per Day ($\$/10^3m^3$)
3912	RUNNING LAKE INTERCONNECTION	253.95	279.35	9.59
2261	RUSSELL CREEK	253.95	279.35	9.59
1311	SADDLE LAKE N.	214.89	236.38	8.12
1310	SADDLE LAKE W.	253.95	279.35	9.59
5004	SALESKI	253.95	279.35	9.59
2281	SAND CREEK	111.72	122.89	4.22
2758	SAWN LAKE	253.95	279.35	9.59
3481	SAWRIDGE SALES	253.95	279.35	9.59
1537	SCOTFIELD	178.72	196.59	6.75
1827	SEDALIA	95.88	105.47	3.62
1036	SEDALIA NORTH	183.35	201.69	6.93
1023	SEDALIA SOUTH	106.62	117.28	4.03
1114	SEDGEWICK	253.95	279.35	9.59
1395	SEDGEWICK EAST	253.95	279.35	9.59
1403	SEDGEWICK NORTH	245.84	270.42	9.29
1447	SEIU CREEK	81.10	89.21	3.06
1370	SEPTEMBER LK N.	253.95	279.35	9.59
1847	SERVICEBERRY CREEK	81.10	89.21	3.06
3862	SEVERN CREEK INTERCONNECTION	81.10	89.21	3.06
1846	SHARROW SOUTH#2	81.10	89.21	3.06
3439	SHEERNESS SALES	81.10	89.21	3.06
2276	SHEKILIE RVR N.	253.95	279.35	9.59
2170	SILVERWOOD	253.95	279.35	9.59
2239	SILVERWOOD N.	230.34	253.37	8.70
1806	SIMON LAKES	253.95	279.35	9.59
2028	SIMONETTE	199.28	219.21	7.53
2033	SIMONETTE NORTH	199.44	219.38	7.54
1354	SLAWA NORTH	252.21	277.43	9.53
2235	SLIMS LAKE	253.95	279.35	9.59
2137	SLOAT CREEK	253.95	279.35	9.59
1521	SMITH	253.95	279.35	9.59
1637	SMITH WEST	253.95	279.35	9.59
2165	SNEDDON CREEK	249.52	274.47	9.43
2253	SNIPE LAKE	253.95	279.35	9.59
2264	SNOWFALL CREEK	253.95	279.35	9.59
2763	SNUFF MOUNTAIN	150.04	165.04	5.67
1065	SOUTH ELKTON	188.27	207.10	7.11
1556	SOUTH SASK RVR	208.79	229.67	7.89
1580	SPEAR LAKE	253.95	279.35	9.59
1856	SPOTTED CREEK	166.72	183.39	6.30
1341	SPRUCEFIELD	253.95	279.35	9.59
1487	SPURFIELD	253.95	279.35	9.59
1581	SQUARE LAKE	253.95	279.35	9.59
1519	ST. BRIDES	253.95	279.35	9.59
1414	ST. LINA	253.95	279.35	9.59
1415	ST. LINA NORTH	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1416	ST. LINA WEST	253.95	279.35	9.59
1534	STANDARD	81.10	89.21	3.06
1131	STANMORE	105.80	116.38	4.00
1156	STANMORE SOUTH	98.72	108.59	3.73
1371	STEELE LAKE	253.95	279.35	9.59
2284	STEEN RIVER	253.95	279.35	9.59
1308	STETTLER SOUTH	190.41	209.45	7.19
1388	STEVEVILLE	81.10	89.21	3.06
1565	STONEY CREEK	241.55	265.71	9.13
1566	STONEY CREEK W.	213.56	234.92	8.07
1115	STRACHAN	92.26	101.49	3.49
1179	STROME-HOLMBERG	146.93	161.62	5.55
2030	STURGEON LAKE S	218.36	240.20	8.25
1423	SUFFIELD WEST	100.89	110.98	3.81
1193	SULLIVAN LAKE	156.79	172.47	5.92
1516	SUNDANCE CREEK	178.41	196.25	6.74
1595	SUNDANCE CRK E.	124.30	136.73	4.70
1674	SUNDAY CREEK	253.95	279.35	9.59
1696	SUNDAY CREEK S.	253.95	279.35	9.59
1079	SUNNYNOOK	81.10	89.21	3.06
1054	SYLVAN LAKE	107.63	118.39	4.07
1187	SYLVAN LAKE EAST #1	102.95	113.25	3.89
1855	SYLVAN LAKE EAST #2	101.76	111.94	3.84
1191	SYLVAN LK SOUTH	119.45	131.40	4.51
1055	SYLVAN LK WEST	117.67	129.44	4.45
2082	TANGENT	253.95	279.35	9.59
2121	TANGENT B	253.95	279.35	9.59
2208	TANGENT EAST	253.95	279.35	9.59
2157	TANGHE CREEK	241.42	265.56	9.12
2204	TANGHE CREEK #2	242.11	266.32	9.15
2747	TANGHE CREEK #3	241.57	265.73	9.13
1440	TAPLOW	81.10	89.21	3.06
1837	TAWADINA CREEK	92.36	101.60	3.49
2076	TEEPEE CREEK	253.95	279.35	9.59
5027	THICKWOOD HILLS	253.95	279.35	9.59
1377	THORHILD	253.95	279.35	9.59
1430	THORHILD WEST	215.08	236.59	8.13
6005	THORNBURY EAST	253.95	279.35	9.59
6002	THORNBURY MARIANA	253.95	279.35	9.59
6001	THORNBURY NORTH	253.95	279.35	9.59
6000	THORNBURY WEST	253.95	279.35	9.59
1029	THREE HILLS CRK	115.37	126.91	4.36
1335	THREE HLS CRK W	81.10	89.21	3.06
1348	TIDE LAKE	81.10	89.21	3.06
1639	TIDE LAKE B	81.10	89.21	3.06
1331	TIDE LAKE EAST	81.10	89.21	3.06

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1268	TIDE LAKE NORTH	81.10	89.21	3.06
1223	TIDE LAKE SOUTH	81.10	89.21	3.06
1412	TIELAND	253.95	279.35	9.59
1314	TILLEBROOK	81.10	89.21	3.06
1644	TILLEBROOK WEST	81.10	89.21	3.06
1169	TILLEY	81.10	89.21	3.06
1839	TILLEY SOUTH #2	185.78	204.36	7.02
2769	TIMBERWOLF	253.95	279.35	9.59
2754	TOPLAND	235.33	258.86	8.89
1841	TORLEA EAST	180.71	198.78	6.83
1621	TORRINGTON EAST	81.10	89.21	3.06
1442	TRAVERS	81.10	89.21	3.06
1574	TROCHU	139.45	153.40	5.27
1848	TUDOR	81.10	89.21	3.06
1343	TWEEDIE	253.95	279.35	9.59
1256	TWEEDIE SOUTH	253.95	279.35	9.59
1190	TWINING	93.26	102.59	3.52
1066	TWINING NORTH	99.37	109.31	3.75
3113	TWINLAKES CK SL	253.95	279.35	9.59
2224	TWO CREEKS	253.95	279.35	9.59
2229	TWO CREEKS EAST	253.95	279.35	9.59
1120	UKALTA	225.11	247.62	8.51
1317	UKALTA EAST	194.32	213.75	7.34
1250	UNITY BORDER	175.78	193.36	6.64
1154	VALE	94.35	103.79	3.56
1212	VALE EAST	123.83	136.21	4.68
2107	VALHALLA	204.81	225.29	7.74
2227	VALHALLA #2	204.77	225.25	7.74
2189	VALHALLA EAST	214.47	235.92	8.10
1801	VANDERSTEENE LK	253.95	279.35	9.59
1056	VERGER	81.10	89.21	3.06
1077	VERGER-HOMESTEA	81.10	89.21	3.06
1203	VERGER-MILLICEN	81.10	89.21	3.06
3916	VETERAN SUMMARY	223.45	245.80	8.44
1606	VICTOR	215.08	236.59	8.13
1347	VIKING EAST	146.17	160.79	5.52
3890	VIKING INTERCONNECTION	138.26	152.09	5.22
1257	VIKING NORTH	200.61	220.67	7.58
1464	VILNA	253.95	279.35	9.59
1527	VIMY	253.95	279.35	9.59
2034	VIRGINIA HILLS	253.95	279.35	9.59
1076	VULCAN	100.00	110.00	3.78
1724	WABASCA	253.95	279.35	9.59
1669	WADDELL CREEK	253.95	279.35	9.59
1736	WADDELL CREEK W	253.95	279.35	9.59
1383	WAINWRIGHT EAST	253.95	279.35	9.59

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1199	WAINWRIGHT S.	242.10	266.31	9.15
6015	WANDER TOWER	253.95	279.35	9.59
1822	WANDERING RIVER	253.95	279.35	9.59
1340	WARDLOW EAST	81.10	89.21	3.06
2133	WARRENSVILLE	253.95	279.35	9.59
1118	WARWICK	150.09	165.10	5.67
1173	WARWICK SOUTH	170.21	187.23	6.43
2029	WASKAHIGAN	146.19	160.81	5.52
2096	WASKAHIGAN EAST	199.75	219.73	7.55
2160	WATER VALLEY	81.10	89.21	3.06
2123	WATINO	253.48	278.83	9.58
1945	WATR1/WATR2 SUM	81.10	89.21	3.06
1570	WATTS	116.48	128.13	4.40
1021	WAYNE NORTH	118.24	130.06	4.47
1039	WAYNE-DALUM	109.27	120.20	4.13
1107	WAYNE-ROSEBUD	81.10	89.21	3.06
1585	WEASEL CREEK	225.54	248.09	8.52
1723	WEAVER LAKE	253.95	279.35	9.59
1780	WEAVER LAKE S.	253.95	279.35	9.59
2207	WEBSTER	253.95	279.35	9.59
2248	WEBSTER NORTH	253.95	279.35	9.59
1825	WELLING	223.39	245.73	8.44
2158	WEMBLEY	187.31	206.04	7.08
6020	WEST DUNCAN	253.95	279.35	9.59
2120	WEST PEMBINA S.	110.05	121.06	4.16
1188	WEST VIKING	172.78	190.06	6.53
1321	WESTLOCK	253.95	279.35	9.59
3871	WESTLOCK INTERCONNECTION	253.95	279.35	9.59
1787	WHISTWOW	253.95	279.35	9.59
2701	WHITBURN EAST	217.95	239.75	8.23
1094	WHITECOURT	187.10	205.81	7.07
2075	WHITELAW	225.23	247.75	8.51
2055	WHITEMUD EAST	229.05	251.96	8.65
3917	WHITEMUD RIVER/WHITEMUD WEST SUMMARY	238.96	262.86	9.03
1345	WHITFORD	187.24	205.96	7.07
1684	WIAU LAKE	253.95	279.35	9.59
1777	WIAU LAKE SOUTH	253.95	279.35	9.59
2005	WILDCAT HILLS	81.10	89.21	3.06
1661	WILDHAY RIVER	131.74	144.91	4.98
1650	WILDUNN CREEK E	81.10	89.21	3.06
2112	WILLESDEN GR N.	84.89	93.38	3.21
2014	WILLESDEN GREEN	82.82	91.10	3.13
1428	WILLINGDON	167.53	184.28	6.33
1652	WILLOW RIVER	253.95	279.35	9.59
1759	WILLOW RIVER N	253.95	279.35	9.59
2019	WILSON CREEK	137.55	151.31	5.20

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
2171	WILSON CREEK SE	138.70	152.57	5.24
1046	WIMBORNE	85.89	94.48	3.25
1234	WIMBORNE NORTH	92.19	101.41	3.48
2707	WINAGAMI LAKE	253.95	279.35	9.59
2012	WINDFALL	139.87	153.86	5.28
1577	WINEFRED RIVER	253.95	279.35	9.59
1628	WINEFRED RVR N.	253.95	279.35	9.59
1671	WINEFRED RVR S.	253.95	279.35	9.59
1070	WINTERING HILLS	81.10	89.21	3.06
1104	WINTERING HLS E	81.10	89.21	3.06
2147	WITHROW	104.94	115.43	3.96
2124	WOKING	253.95	279.35	9.59
2214	WOLVERINE RIVER	253.95	279.35	9.59
1035	WOOD RIVER	175.29	192.82	6.62
3425	WOOD RVR SALES	175.08	192.59	6.61
2765	WOOSTER	141.14	155.25	5.33
2057	WORSLEY EAST	253.95	279.35	9.59
1342	YOUNGSTOWN	169.87	186.86	6.42
2060	ZAMA LAKE	253.95	279.35	9.59
1944	ZAMA LAKE SUMMARY	253.95	279.35	9.59

TABLE 1.1-2 ATTACHMENT 2

Distance Band	Maximum Distance Between Receipt Point and Delivery Point (km)		FT-P Demand Rate per Month
	From	To	($\$/10^3m^3$)
1	0	25	96.44
2	>25	50	106.04
3	>50	75	115.65
4	>75	100	125.25
5	>100	125	134.85
6	>125	150	144.46
7	>150	175	154.06
8	>175	200	163.66
9	>200	225	173.27
10	>225	250	182.87
11	>250	275	192.47
12	>275	300	202.07
13	>300	325	211.68
14	>325	350	221.28
15	>350	375	230.88
16	>375	400	240.49
17	>400	425	250.09
18	>425	450	259.69
19	>450		269.30