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March 31, 2008

Alberta Utilities Commission

Filed Electronically

4th Floor
425 – 1 Street S.W.
Calgary Alberta
T2P 3L8

Attention: **Mr. Wade Vienneau,**
Executive Director, Utilities

Dear Sir:

Re: NOVA Gas Transmission Ltd. ("NGTL")
2008-2009 Revenue Requirement Settlement Application

Enclosed for filing with the AUC is NGTL's 2008-2009 Revenue Requirement Settlement Application.

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 Ben Leung by e-mail at ben_leung@transcanada.com and to alberta_system@transcanada.com, or by phone at 920-2275 and to Jennifer Scott by e-mail at jennifer_scott@transcanada.com or by phone at 920-2977.

Yours truly,

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

Original Signed by

Kristine Delkus
Deputy General Counsel,
Pipelines and Regulatory Affairs

Enclosures

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

NOVA Gas Transmission Ltd.

2008-2009 Revenue Requirement Settlement Application

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ALBERTA UTILITIES COMMISSION

IN THE MATTER OF the *Alberta Utilities Commission Act*, S.A. 2007, c. A-37.2 and the Regulations made 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 Utilities Commission for an Order approving the 2008-2009 Revenue Requirement Settlement.

2008-2009 REVENUE REQUIREMENT SETTLEMENT APPLICATION

NOVA Gas Transmission Ltd. ("NGTL") applies to the Alberta Utilities Commission ("AUC") under Section 45 of the *Gas Utilities Act* and the provisions of AUC Rule 018, Rules on Negotiated Settlements, for an Order:

(a) approving the 2008-2009 Revenue Requirement Settlement ("Settlement") in its entirety;

(b) making the interim rates charged for the period of January 1, 2008 to April 30, 2008 final;

(c) approving the interim rates as final rates for 2008 for the period of May 1, 2008 to December 31, 2008; and

(d) granting such further and other relief as NGTL may request or the AUC 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 AUC.

Respectfully submitted.

March 31, 2008
Calgary, Alberta

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

Per: ______***Original Signed by***____
Kristine Delkus
Deputy General Counsel,
Pipelines and Regulatory Affairs

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: Ben Leung
Regulatory Services

Telephone: (403) 920-2275
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E-mail: alberta_system@transcanada.com

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

Attention: Jenny Scott
Senior Legal Counsel
Law & Regulatory Research

Telephone: (403) 920-2977
Fax: (403) 920-2354
E-mail: jennifer_scott@transcanada.com

1.2 INTRODUCTION

Q1. What is the purpose of this Application?

A1. NGTL seeks AUC approval of the 2008-2009 Revenue Requirement Settlement. The Settlement establishes the mechanisms through which the 2008 and 2009 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 AUC 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. On July 11, 2007, NGTL applied to the Alberta Energy and Utilities Board ("Board"), predecessor to the AUC, for approval to initiate negotiations with respect to its revenue requirement or components of its revenue requirement for a term of not more than three years commencing January 1, 2008.

On July 31, 2007, the Board approved NGTL's request to commence a negotiated settlement with respect to its revenue requirement. The Board directed NGTL to provide the Board, prior to the commencement of negotiations, general rate application documentation showing NGTL's prospective forecast of its revenue requirement for the test years it proposed to negotiate and a list of those invited to participate in the negotiations. If a settlement was not reached, NGTL was directed to file a general rate application ("GRA") in the last quarter of 2007 for a test period commencing January 1, 2008.

On August 23, 2007, in response to the Board's direction, NGTL provided a revenue requirement information package for 2008-2010 to the Board, the Tolls, Tariff, Facilities, and Procedures Committee ("TTFP"), interested parties to NGTL's 2005-2007 Revenue Requirement Settlement (Application Number 1392296) and NGTL's 2005 GRA Phase 2 (Application Number 1396409), and to Alberta System shippers.

On August 31, 2007, the Board accepted NGTL's August 23, 2007 filing. It also advised NGTL that as a matter of compliance with the Board's negotiated settlement rules in EUB Directive 018, a Board staff member would participate in the settlement process as an observer.

On September 4, 2007, NGTL invited members of the TTFP, interested parties to NGTL's 2005 GRA Phase 2 and 2005-2007 Revenue Requirement Settlement, and all Alberta System shippers to participate in the settlement negotiations. A copy of the invitation is provided in Appendix B.

On September 5, 2007, NGTL published notices in the Calgary Herald, the Calgary Sun, the Edmonton Journal, and the Edmonton Sun inviting interested and affected parties to participate in the discussions. Copies of the notices are provided in Appendix C. NGTL also invited Board staff to observe the negotiations. The first meeting was held on September 13, 2007.

On December 10, 2007, NGTL provided the Board with an update on the progress of the negotiations. At that time, NGTL was optimistic that it would reach consensus and settle all or portions of its revenue requirement with stakeholders. However, NGTL was experiencing resourcing and timing constraints in progressing work necessary to finalize a GRA for filing while concurrently meeting information and negotiation requirements for a potential settlement and the requirements of several other Board proceedings. NGTL requested that the Board extend the deadline for NGTL to file a GRA from the last quarter of 2007 to the first quarter of 2008. NGTL indicated that it would file a settlement application, a GRA, or some combination by the end of the first quarter of 2008.

On December 14, 2007, the Board granted NGTL's request for an extension. The Board found that the additional time should afford NGTL and stakeholders further opportunity to negotiate a settlement agreement, or in the alternative, NGTL more time to complete its GRA.

Over the course of the negotiations between September and March, NGTL met with stakeholders numerous times resulting in the Settlement.

Q2. Did NGTL follow the general requirements of the AUC's Rules on Negotiated Settlement under Rule 018 in reaching the Settlement?

A2. Yes. NGTL commenced negotiations under the Board's Directive 018 Negotiated Settlement Rules. On January 1, 2008 the Board became the AUC, and on January 2, 2008 the AUC approved the Rules on Negotiated Settlement, Rule 018, which replaced the Board Directive 018. NGTL concluded the negotiations under Rule 018, and throughout the process believes that it has followed the requirements set forth by both Directive 018 and Rule 018. The settlement process was open and fair. It provided an appropriate forum for 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 AUC staff member observed the negotiations.

Q3. Which parties participated in the settlement negotiations?

A3. A list of parties that executed confidentiality agreements to participate in the negotiation process is provided in Appendix D. The participants represent a broad cross-section of Alberta System stakeholders, including producers, marketers, intra-Alberta industrial and residential customers, and ex-Alberta delivery customers, either directly and/or through their representative associations.

Q4. Are there any issues related to the 2008 or 2009 Alberta System revenue requirement that were not resolved through the Settlement?

A4. NGTL is not aware of any outstanding issues related to the 2008 or 2009 revenue requirement.

Q5. Who are the signatories to the Settlement?

A5. The Settlement was signed by:

- NOVA Gas Transmission Ltd.;
- The Canadian Association of Petroleum Producers;
- The Industrial Gas Consumers of Alberta; and
- The Office of the Utilities Consumer Advocate.

In addition, the following parties have indicated that they support the Settlement:

- Canadian Natural Resources Limited;

- ConocoPhillips Canada;
- Devon Canada Corporation;
- EnCana Corporation;
- ExxonMobil Canada;
- Harvest Operations Corp.;
- Imperial Oil Resources; and
- Talisman Energy Canada.

Q6. Is the Settlement opposed by any of the participants in the negotiations?

A6. No. NGTL understands that parties, other than those identified above, neither support nor oppose the Settlement.

Q7. Does that conclude NGTL's evidence in this section?

A7. Yes.

3.0 TERMS OF THE 2008-2009 REVENUE REQUIREMENT SETTLEMENT

3.1 Structure 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 2008 and 2009 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 AUC in its entirety. The Settlement results from and reflects compromises made 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, Return on Equity, Income Taxes, and Depreciation. Fixed Operating Costs encompass all operating, maintenance and administration costs (with the exception of Pipeline Integrity and Repair and Overhaul costs).

Certain of the fixed cost components are “black box” amounts. For 2008, this includes Operating Costs, Return on Equity and Income Taxes for which only a combined amount has been identified. Any variances between the fixed “black box” amounts and actual costs shall be to the account of NGTL subject to return on equity and income tax adjustment mechanisms through the Return on Equity and Income Tax Deferral Account.

For each year of the Settlement, the Return on Equity and Income Tax Deferral Account will be used to account for variances between forecast and actual rate base and changes in tax laws. Adjustment amounts will be reflected in the revenue requirement for the following year.

For reporting purposes only, 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%. NGTL will report annual Settlement earnings as a separate line item on Schedule 2.5 of the AUC's Annual Financial and Operating Reporting package.

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

A3. All other costs will be flow-through including:

- debt costs;
- municipal taxes;
- transportation by others;
- regulatory hearing costs;
- pipeline integrity costs (expense);
- repair and overhaul costs (expense);
- annual foreign exchange amortization amount;
- foreign exchange on interest payments;
- CO_2 management service costs (expense);
- uninsured losses;
- emission compliance costs; 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. 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. NGTL will use deferral accounts to record and account for variances between forecast and actual flow-through costs.

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

3.2 Key Terms of the Settlement

Q4. Please describe the key terms for determining the 2008 Revenue Requirement

A4. Operating Costs, Return on Equity and Income Taxes will be fixed at $397.0 million, subject to return on equity and income tax adjustment mechanisms. Depreciation will be fixed at $249.8 million. All other costs will be flow-through.

NGTL's return on equity will be adjusted to account for any difference between the actual and forecast rate base for 2008. Forecast rate base amounts are provided in Appendix 2 to the Settlement. The adjustment mechanism for return on equity will be calculated using the generic rate of return of 8.75% on a deemed common equity of 35%. Similarly, an adjustment mechanism will be used to account for any differences in income tax including differences between the actual and forecast rate base and any changes to the income tax and CCA rates. NGTL will include the adjustment for return on equity and income tax in the Return on Equity and Income Tax Deferral Account to be included in the subsequent year's revenue requirement.

Q5. Please describe the key terms for determining the 2009 Revenue Requirement

A5. Operating Costs for 2009 will be fixed at $203.5 million. Return on Equity and Income Taxes will be fixed at $205.3 million, subject to return on equity and income tax adjustment mechanisms. Depreciation will be held constant at $249.8 million. All other costs will be flow-through.

If there is a Cost of Capital proceeding affecting NGTL in 2009, the results from such a decision will be used to calculate NGTL's return on equity and income tax. Otherwise, NGTL's return on equity will be adjusted to account for any difference between the actual and forecast rate base for 2009. Forecast rate base amounts are provided in Appendix 2 to the Settlement. The adjustment mechanism for return on equity will be calculated using the 2009 generic rate of return on a deemed common equity of 35%. Similarly, an adjustment mechanism will be used to account for any differences in income tax including differences between the actual and forecast rate base and any changes to the income tax and CCA rates. NGTL will include the adjustment for return on equity and income tax in the Return on Equity and Income Tax Deferral Account to be included in the subsequent year's revenue requirement.

3.3 Annual Revenue Requirement

Q6. What is the 2008 revenue requirement as determined under the provisions of the Settlement?

A6. The 2008 revenue requirement is $1,145.2 million as provided in Appendix E. This amount includes the amount agreed to in the Settlement, plus $29.0 million of deferrals from 2007.

Q7. How does the 2008 revenue requirement compare to the approved 2007 revenue requirement?

A7. Appendix E provides a comparison between the 2008 revenue requirement and the approved revenue requirement for 2007. The 2008 revenue requirement excluding deferrals is $26.4 million lower than the approved 2007 revenue requirement excluding deferrals.

Q8. What is the impact of the Settlement on 2008 rates, tolls and charges?

A8. NGTL provides in Figure 1.1-1 of Appendix H, 2008 rates, tolls and charges calculated in accordance with the rate design approved by the EUB in Decision 2006-010, forecast 2008 contract demand and throughput quantities, as outlined in Appendix G, and the 2008 revenue requirement provided in Appendix E.

In addition, NGTL received funds related to the Calpine Corporation bankruptcy settlement in the amount of $32.7 million including carrying charges. NGTL has applied this amount as a credit to the 2008 revenue requirement as provided in Figure 1.1-1 of Appendix H.

Q9. What rates, tolls and charges for services is NGTL currently charging?

A9. NGTL is currently charging interim rates, tolls and charges for service on the Alberta System, which the EUB approved in Decision 2007-109.[2]

Q10. When will NGTL amend the 2008 interim rates to incorporate the revised 2008 revenue requirement determined through the Settlement?

A10. The rates determined using the revenue requirement resulting from the Settlement are within 1% of the 2008 interim rates. Since the effect on the rates is immaterial, NGTL requests that the 2008 interim rates be made final for the period January 1, 2008 to April 30, 2008 and the final rates for the period May 1, 2008 to December 31, 2008 are set at the same level as the interim rates. The recovery of variances between the revenue collected in 2008 and the final revenue requirement for 2008 will be deferred to 2009.

Q11. Has the revenue requirement for 2009 been determined?

A11. No. The Operating Costs and Depreciation amounts are fixed at $203.5 million and $249.8 million respectively as provided in the Settlement. The Return on Equity and Income Tax are fixed and included in the "black box" of the revenue requirement and are forecast at $205.3 million and are subject to the applicable adjustment mechanisms for 2009 as provided in the Settlement. All flow-through cost components and applicable deferral account balances will be estimated at the time of the respective rate applications.

Q12. How will rates for 2009 be calculated?

A12. For 2009, NGTL will calculate interim rates, tolls and charges based on the forecast revenue requirement or the 2008 approved revenue requirement, a forecast of 2009 firm transportation contract demand quantity and throughput, and the approved rate design in place at the time. On or before December 1, 2008, the interim rates, tolls

[2] Alberta Energy and Utilities Board, Decision 2007-109, NOVA Gas Transmission Ltd., 2008 Interim Rates, Tolls and Charges (December 20, 2007).

and charges will be provided to interested parties and filed with the AUC for approval.

If there is a cost of capital proceeding affecting NGTL's 2009 revenue requirement, then the rates for 2009 will be calculated based on the outcome of such proceeding. Otherwise, the final rates, tolls and charges for 2009 will be calculated and provided to interested parties and filed with the AUC for approval on or before March 15, 2009. Such final rates shall enable NGTL to collect its annual revenue requirement, recognizing amounts collected under interim rates.

3.4 Deferral and Reserve Accounts

Q13. What deferral and reserve accounts will be used for 2008 and 2009?

A13. NGTL will use the following deferral accounts for 2008 and 2009:

- Revenue;
- CO_2 Management Service Deferral Account;
- Flow-through Costs; and
- Return on Equity and Income Tax Deferral Account.

The Revenue deferral account will continue to be used for the same purpose it was used in 2007 and will consist of:

- Variances in revenue resulting from actual Firm Transportation Contract Demand revenue differing from the forecast of Firm Transportation Contract Demand revenue used in establishing the applicable year's rates, including all variances related to all Firm Transportation.
- Variances in revenues resulting from actual Interruptible Transportation Services revenue differing from the forecast of Interruptible Transportation Services revenue used in establishing the applicable year's rates, including all variances from interruptible receipt and interruptible delivery revenues net of alternate access, Facilities Connection Service, Pressure/Temperature Service and Other Services.

The CO_2 Management Service deferral account will continue to be utilized in the same manner it was used for in 2007. 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 continue to be utilized in the manner it was used for in 2007. It 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.

The Return on Equity and Income Tax Deferral Account is a new deferral account to be used for the term of the Settlement as described in Section 3.2 of this Application.

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.[3]

Q14. How will the deferral accounts work?

A14. 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 will be calculated at the Bank of Canada Bank Rate plus 1½ percent 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 at the end of each year, including carrying charges, in the calculation of the subsequent year's revenue requirement.

[3] EUB Decision 2004-069, page 47.

Q15. How will NGTL dispose of the 2007 deferral account balances?

A15. NGTL has calculated the 2007 deferral account balances based on the 2007 revenue requirement amounts approved by the Board in Decision 2007-109.[4] In addition, 50% of the 2007 severance costs have been deferred to 2008 in accordance with Section 3.1(a) of the 2005-2007 Revenue Requirement Settlement, approved by the Board in Decision 2005-057[5]. The balances, including applicable carrying charges, are included in the 2008 revenue requirement as per the terms of the Settlement. The deferral account details are provided in Appendix F.

3.5 Conclusion

Q16. Why does NGTL believe that the AUC should approve the Settlement?

A16. 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 customers. The participants are sophisticated parties who are knowledgeable about the operations of the Alberta System. Their aggregate support of the Settlement is a strong basis on which the AUC can reasonably conclude that the Settlement is in the interests of the stakeholders specifically and the public generally.

- The 2008 revenue requirement under the terms of the Settlement will result in lower costs to shippers than in 2007.

[4] Alberta Energy and Utilities Board, Decision 2007-109, NOVA Gas Transmission Ltd., 2008 Interim Rates, Tolls and Charges (December 20, 2007).

[5] Alberta Energy and Utilities Board, Decision 2005-057, NOVA Gas Transmission Ltd., 2005-2007 Revenue Requirement Settlement (June 7, 2005).

  - The fixed component for 2008 of the Settlement (operating costs, return on equity, and income taxes) is lower by $33 million than the same costs in 2007. Details are provided in Appendix E.

  - Depreciation is $39.4 million lower in 2008 than in 2007. The fixed amount of $249.8 million results in a composite depreciation rate of approximately 3.18% in 2008, which is appropriate for the Alberta System based on relevant factors and is similar to rates charged by other pipeline systems.

  - The revenue requirement excluding deferrals in 2008 is $26.4 million lower than the revenue requirement excluding deferrals in 2007.

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

- The Settlement will result in greater regulatory efficiency and certainty than a traditional litigated hearing process. It defines a method for determining revenue requirements for a two-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 two years.

- The Settlement contains appropriate reporting and audit provisions to ensure sufficient information disclosure and accountability to parties to the Settlement and the AUC.

- 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 existing law and the policies of the AUC.

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

Q17. Does that conclude NGTL's evidence in this section?

A17. Yes.

Appendix A
2008-2009 Revenue Requirement Settlement

NOVA Gas Transmission Ltd.
2008-2009 Revenue Requirement Settlement (the "Settlement")

OVERVIEW

This Settlement includes all elements of NOVA Gas Transmission Ltd.'s ("NGTL") revenue requirement but does not extend to any rate design, accountability, services or competitive issues. This Settlement establishes:

(a) Certain revenue requirement amounts and the methodology for calculating such amounts for the two year period commencing January 1, 2008 to and including December 31, 2009 ("the Term"); and

(b) Both fixed and flow-through cost components of the revenue requirement for the Term.

Rates during the Term shall 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 Alberta Utilities Commission ("AUC").

1. REVENUE REQUIREMENT FOR 2008

The revenue requirement for the period commencing January 1, 2008 to and including December 31, 2008 ("2008") shall be calculated based on inclusion of certain fixed costs (the "2008 Fixed Costs") and a forecast of flow-through costs (the "2008 Flow-Through Costs") set out in Appendix 1. For all 2008 Flow-Through Costs, any variance between actual and forecast costs shall be adjusted for in the appropriate deferral accounts (the "2008 Deferral Accounts").

(A) Fixed Components

Operating costs, return on equity, income taxes and depreciation shall be 2008 Fixed Costs.
.

(i) Operating Costs, Return on Equity ("ROE"), and Income Taxes

Operating costs (excluding pipeline integrity, repair and overhaul costs, which shall be included in the 2008 Flow-Through Costs), return on equity, and income taxes shall be $397,000,000. Any variance between $397,000,000 and actual costs incurred for operating costs, return on equity, and income taxes shall be for the account of NGTL subject to the following adjustment mechanisms:

a. NGTL's return on equity shall be adjusted to account for any difference between actual and forecast rate base for 2008. The adjustment shall be calculated as:

[Actual Rate Base – Forecast Rate Base] * [35% * 8.75%]

b. NGTL's income tax expense shall be adjusted to account for any difference between actual and forecast for 2008. The adjustment shall be calculated as:

[Income Tax using actual 2008 information (rate base, CCA rates, income tax rate, other) with an ROE of 8.75% on 35% equity] – [Income Tax using forecast 2008 information with an ROE of 8.75% on 35% equity]

The adjustment for return on equity and income tax, including carrying charges, will be deferred to 2009. Forecast information is provided in Appendix 2.

(ii) Depreciation

Depreciation expense shall be fixed at $249,800,000. This amount shall be applied pro rata to each of the asset classes based upon respective 2007 asset class rates.

(B) Flow-through Components

All other costs for 2008, including without limitation, all costs set out in 1(B)(i) to (xii) and any balances in deferral accounts for 2007, determined in accordance with the NGTL 2005-2007 Revenue Requirement Settlement shall be 2008 Flow-Through Costs. Any variance between the actual and forecast 2008 Flow-Through Costs shall be included in the appropriate 2008 Deferral Account to be included in the revenue requirement for 2009. Carrying charges on the 2008 Deferral Accounts shall be calculated using the Bank of Canada Bank Rate plus 1½%.

2008 Flow-Through Costs shall include but not be limited to the following:

(i) Revenue

Any variance between the actual and forecast revenue for 2008 shall be included in the appropriate 2008 Deferral Account.

(ii) Debt

Debt costs for 2008 are forecast to be $207,900,000. Actual debt costs shall be determined based on a deemed debt structure of 65%.

(iii) Foreign Exchange on Interest Payments

Foreign exchange on interest payments for 2008 is forecast to be ($7,200,000).

(iv) Municipal Taxes

Municipal taxes for 2008 are forecast to be $98,100,000.

(v) Uninsured Losses

Uninsured losses for 2008 are forecast to be $4,000,000.

(vi) Transportation by Others ("TBO") Costs

TBO costs for 2008 are forecast to be $89,056,000. Any additional TBO costs for new TBO arrangements shall be added to the actual TBO costs for 2008, subject to the approval of the AUC.

(vii) Emissions Compliance Costs

Emissions compliance costs for 2008 are forecast to be $8,292,000.

(viii) Regulatory Hearing Costs

The regulatory hearing costs for 2008 are forecast to be $3,006,000. NGTL will not carry a balance in excess of $5,000,000 at any time.

(ix) Pipeline Integrity Costs

Pipeline integrity costs for 2008 are forecast to be $37,729,000.

(x) Repair and Overhaul Costs

Repair and overhaul costs for 2008 are forecast to be $23,631,000.

(xi) Annual Foreign Exchange Amortization Amount

The Foreign Exchange Amortization Amount for 2008 is forecast to be $2,308,000. The mechanism established in the 2001 Alberta System Rate Settlement for amortization of foreign exchange gains and losses related to long-term debt shall be modified as follows:
If $\sum FX < 0$ then $AFX = FXR/(2029 – 2008)$ else $AFX = (\sum FX – FXR)/(2029 – 2008)$

(xii) CO_2 Management Service Costs

CO_2 Management Service costs for 2008 are forecast to be $2,541,000.

2. REVENUE REQUIREMENT COMPONENTS FOR 2009

The revenue requirement for the period commencing January 1, 2009 to and including December 31, 2009 ("2009") shall be calculated based on inclusion of certain fixed costs (the "2009 Fixed Costs") and a forecast of flow-through costs (the "2009 Flow-Through Costs"), which shall be adjusted for in the appropriate deferral accounts (the "2009 Deferral Accounts").

(A) Fixed Components

Operating costs, return on equity, income taxes and depreciation shall be 2009 Fixed Costs.

(i) Operating Costs, Return on Equity, and Income Taxes

Operating costs (excluding pipeline integrity, repair and overhaul costs, which shall be included in 2009 Flow-Through Costs) shall be fixed at $203,500,000. Any variance between $203,500,000 and actual costs incurred for operating costs shall be for the account of NGTL.

Return on equity and income taxes for 2009 are forecast to be $205,300,000. If a 2009 Cost of Capital proceeding affecting NGTL occurs, the results from such decision shall be used to calculate NGTL's return on equity and income tax. Otherwise:

a. NGTL's return on equity shall be adjusted to account for any difference between actual and forecast rate base for 2009. The adjustment shall be calculated as:

   [Actual Rate Base – Forecast Rate Base] * [35% * 2009 ROE Formula]

b. NGTL's income tax expense shall be adjusted to account for any difference between actual and forecast for 2009. The adjustment shall be calculated as:

   [Income Tax using actual 2009 information (rate base, CCA rates, income tax rate, other) with ROE formula on 35% equity] – [Income Tax using forecast 2009 information with ROE formula on 35% equity]

   The adjustment for return on equity and income tax, including carrying charges, will be deferred to 2010. Forecast parameters are provided in Appendix 2.

(ii) Depreciation

Depreciation expense for 2009 shall be fixed at $249,800,000. This amount shall be applied pro rata to each of the asset classes based upon respective 2007 asset class rates.

(B) "Flow-Through" Components

All other costs for 2009, including without limitation, all costs set out in 2(B)(i) to (v) and any balances in the 2008 Deferral Accounts shall be 2009 Flow-Through Costs. Any variance between the actual and forecast costs for 2009 shall be included in the appropriate 2009 Deferral Account and included in the revenue requirement for 2010. Carrying charges on 2009 Deferral Accounts shall be calculated using the Bank of Canada Bank Rate plus 1½%.

2009 Flow-Through Costs shall include but not be limited to the following:

(i) Revenue

Any variance between the actual and forecast revenue for 2009 shall be included in the appropriate 2009 Deferral Account.

(ii) Debt

If a 2009 Cost of Capital proceeding affecting NGTL occurs, the results from such decision shall be applied to NGTL's debt costs. Otherwise actual debt costs shall be determined based on a deemed debt structure of 65%.

(iii) TBO Costs

Any additional TBO costs for new TBO arrangements shall be added to the actual TBO costs for 2009, subject to the approval of the AUC.

(iv) Regulatory Hearing Costs

NGTL will not carry a balance in excess of $5,000,000 at any time.

(v) Annual Foreign Exchange Amortization Amount

The mechanism established in the 2001 Alberta System Rate Settlement for amortization of foreign exchange gains and losses related to long-term debt shall be modified as follows:
If $\sum FX < 0$ then $AFX = FXR/(2029 – 2009)$ else $AFX = (\sum FX – FXR)/(2029 – 2009)$

3. OTHER PROVISIONS

(A) Settlement Package

The parties agree that approval of this Settlement in its entirety as a package is a requirement for the Settlement to be binding on any party. The terms and conditions of this Settlement 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.

(B) Confidentiality

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

(C) 2009 and 2010 Interim Rates

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

(D) 2009 Final Rates

If there is no Cost of Capital proceeding affecting NGTL in 2009, the final rates, tolls and charges shall be calculated and provided to interested parties and filed with the AUC for approval on or before March 15, 2009. If there is a Cost of Capital proceeding affecting NGTL in 2009, final rates shall be calculated based on the results of such proceeding. Such final rates shall enable NGTL to collect its annual revenue requirement, recognizing amounts collected under interim rates.

(E) Reporting

NGTL will report annually to all parties using the AUC reporting package augmented with the additional schedules set out in Appendix 3.

NGTL's equity shall be reported based on the AUC deemed equity structure and the ROE formula for return on equity. For 2008, this is 35% equity and 8.75% return on equity.

(F) Audit

The Tolls, Tariff, Facilities, and Procedures Committee may conduct an independent audit of this Settlement and will use reasonable efforts to complete it prior to December 15, 2010. The audit will verify compliance by NGTL with the terms of this Settlement and verify the validity of the information provided in the reporting packages. Subject to the execution of an acceptable confidentiality agreement by the auditor, NGTL will provide reasonable access to all necessary source data. The costs and expenses for the audit will be paid by NGTL and added to NGTL's revenue requirement for the subsequent year.

(G) Deemed Weighted Average Cost Capital

During the Term, for any calculation under the Tariff that includes operating return, rate of return on rate base or any calculation for an allowance for funds used during construction, operating return, rate of return on rate base or allowance for funds used during construction shall be deemed to be 8.0% unless there is a Cost of Capital proceeding affecting NGTL in 2009 in which case the deemed weighted average cost of capital for 2009 shall be calculated based on the results of such proceeding. The rate of 8.0% shall not be interpreted as a reflection of the actual rate of return achieved by NGTL during the Term and shall set no precedent and shall be without prejudice to any position any party may take regarding the appropriate or fair rate of return for NGTL.

(H) Allocation of TransCanada Costs to NGTL

During the term of this Settlement, if there is a substantive change to the methodology used 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. 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 17 day of MARCH, 2008.

Company or Association Name (please print)

NOVA GAS TRANSMISSION LTD.

Per: ______ Vice President, Commercial - West
Canadian Pipelines

Title: ______

Per: ______

Title: ______
Max Feldman
Senior Vice President
Canadian and Eastern US Pipelines

4. 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 18TH day of March, 2008.

Company or Association Name (please print)

CAPP

Per: [signature]

Title: VICE PRESIDENT

Per: [signature]

Title: Manager, Natural Gas

Received Time Mar 18 3:18PM

4. 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 20th day of March, 2008.

Company or Association Name (please print)

Industrial Gas Consumers Association of Alberta

Per: ____________________

Title: ____________________

Per: Greig Sproule

Title: Executive Director

4. 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 25th day of March, 2008.

Company or Association Name (please print): Office of the Utilities Consumer Advocate

____

Per: David Gray

Title: Executive Director

Appendix 1

This table summarizes the 2008 Fixed Costs agreed to in this Settlement and provides an illustration of the 2008 Flow-Through Costs. This table does not include deferral account balances from 2007 or projected 2008 Deferral Account balances. The final revenue requirement for 2008 will be adjusted to include all deferral account balances from 2007.

$ millions		2008
2008 Fixed Costs	Operating Costs, Return on Equity, and Income Taxes	397.0
	Depreciation	249.8
	Total Fixed Costs	**646.8**
2008 Flow-Through Costs		
	Debt	207.9
	FX on Interest Payments	(7.2)
	Municipal Taxes	98.1
	Uninsured Losses	4.0
	TBO Cost	89.1
	Emissions Compliance Costs	8.3
	Regulatory Hearing Costs	3.0
	Pipe Integrity Costs	37.7
	Repair and Overhaul Costs	23.6
	FX Amortization Amount	2.3
	CO_2 Management Service Costs	2.5
	Total Flow-Through Costs	**469.3**
Total Revenue Requirement		**1,116.1**

Appendix 2 - Forecast Parameters

	2008	2009
Weighted Average Rate Base ($000)	4,236,940	4,656,053
Income Tax Rate	29.5%	29.5%
Capital Cost Allowance ($000)	192,631	232,257
AFUDC Interest Component ($000)	9,386	15,186
Other Income Tax Deductions ($000)	5,372	3,373

2008 & 2009 Capital Cost Allowance (CCA)	CCA Class	Max Rate
	01	4%
	02	6%
	03	5%
	06	10%
	07	15%
	08	20%
	10	30%
	10a	45%
	10b	55%
	12	100%
	13	S/L
	17	8%
	49	8%

Appendix 3-1

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

O&M - Total Company
($ thousands)

Line No.	Particulars	Alberta System	Mainline	Foothills	Other	Total Company
1	Field Operations					
2	Engineering					
3	Operations & Engineering Support Services					
4	Operations & Engineering Programs					
5	Commercial & Regulatory					
6	Business Services					
7	Information Systems					
8	General Expenses					
9	TOTAL OPERATING COSTS	-	-	-	-	-
10	Percent of Total					
11	Total FTEs					

Appendix 3-2

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

O&M

Line		Average # of FTEs [1]
1.	Field Operations	
2.	Engineering	
3.	Operations & Engineering Support Services	
4.	Commercial & Regulatory	
5.	Business Services	
6.	Information Systems	
7.	Total FTEs	

[1] Average number of full-time equivalents allocated to the Alberta System.

Appendix 3-3

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

FOREIGN EXCHANGE ON INTEREST PAYMENTS
ON LONG-TERM DEBT
($ thousands)

Line		Debt Issue US$	Interest Rate (%)	Interest Payments (US$)	Date of Interest Payment	Issue Exchange Rate	Actual Exchange Rate	Foreign Exchange Loss/(Gain)
1.	7.50% MTN #5	32,500	7.5000%	1,219	Feb 20	1.18161		
2.	7.875% U.S. $200 mm	200,000	7.8750%	7,875	Apr 1	1.24272		
3.	7.70% U.S. $50 mm	50,000	7.7000%	1,925	Jun 15	1.46170		
4.	7.70% U.S. $150 mm	150,000	7.7000%	5,775	Jun 15	1.22748		
5.	8.50% U.S. $175 mm (Swap - 8.5% Fixed) (1)	138,000	8.5000%	5,865	Jun 15	1.27455		
6.	7.50% MTN #5	32,500	7.5000%	1,219	Aug 20	1.18161		
7.	7.875% U.S. $200 mm	200,000	7.8750%	7,875	Oct 1	1.24272		
8.	7.70% U.S. $50 mm	50,000	7.7000%	1,925	Dec 15	1.46170		
9.	7.70% U.S. $150 mm	150,000	7.7000%	5,775	Dec 15	1.22748		
10.	8.50% U.S. $175 mm (Swap - 8.5% Fixed) (1)	138,000	8.5000%	5,865	Dec 15	1.27455		
11.	Total Foreign Exchange Loss on Interest Payments							

(1) US $175 Million partially swapped to Cdn.

Appendix 3-4

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

CAPITAL COST ALLOWANCE
($ thousands)

LINE	CCA CLASS	UCC OPENING BALANCE	ADJUSTMENTS TO OPENING BALANCE	COST OF ADDITIONS	NET SALVAGE	UCC BEFORE DEFERRED CAPITAL COST	EXCESS	CAPITAL COST DEFERRED	UCC BEFORE CCA	MAX RATE	CAPITAL COST ALLOWANCE	UCC ENDING BALANCE
1.	**01**											
2.	**02**											
3.	**03**											
4.	**06**											
5.	**07**											
6.	**08**											
7.	**09**											
8.	**10**											
9.	**10a**											
10.	**12**											
11.	**13**											
12.	**17**											
13.	**49**											
14.		-	-	-	-	-	-	-	-		-	-
15.		**In Service Additions**	**Total**									
16.			**AFUDC**									
17.			**CEC**									
			Land									
18.			**Removal**									
19.				-								

CUMULATIVE ELIGIBLE CAPITAL

	CEC	OPENING BALANCE	ADJUSTMENTS TO OPENING BALANCE	COST OF ADDITIONS	EXCLUDE 25 % OF ADDITIONS	ELIGIBLE BALANCE	Rate	CEC DEDUCTION	CLOSING BALANCE
20.				-	-	-		-	

Appendix 3-5

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT
($Thousands)

LINE NO.	DESCRIPTION	MATURITY DATE	AMOUNT (US$)	HISTORICAL EXCHANGE RATE	DEC 31, 2008 EXCHANGE RATE	CURRENT YEAR LOSS/(GAIN)
	(a)	(b)	(c)	(d)	(e)	(f)
1	8.50% US$175MM [1]	2012	138,000	1.27455		
2	7.875% US$200MM	2023	200,000	1.24272		
3	7.70% US$150MM Note Payable to TCPL	2029	150,000	1.22748		
4	7.70% US$50MM Note Payable to TCPL	2029	50,000	1.46170		
5	7.50% Medium Term Note - US$32.5MM	2026	32,500	1.18160		
						-
6	Prefunded / (Unfunded) Foreign Exchange on Long Term Debt Balance at January 1, 2008					
7	**Total**		570,500			-
8	Annual Foreign Exchange Amortization Amount (Line 6 divided by 21)					-
9	Income Tax Payable					-
10						-

Appendix 3-6

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

RATE BASE
($ thousands)

Line	Particulars	Jan 1	Jan 31	Feb 28	Mar 31	Apr 30	May 31	June 30	July 31	Aug 31	Sep 30	Oct 31	Nov 30	Dec 31	13 Month Weighted Average	Totals
1.	Opening Gas Plant in Service															
2.	Additions															
3.	Retirements															
4.	Gas Plant in Service															
5.	Opening Accumulated Depreciation															
6.	Depreciation Expense															
7.	Retirements															
8.	Accumulated Depreciation															
9.	Net Gas Plant in Service															
10.	Cash Working Capital															
11.	Materials & Supplies Inventory															
12.	Linepack Gas															
13.	Unamortized Capital Assets															
14.	FX on LTD Principle Reserve															
15.	Pension and OPEBS															
16.	Rate Base															

Appendix 3-7

NOVA GAS TRANSMISSION LTD.
2008-2009 REVENUE REQUIREMENT SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2008

GAS PLANT UNDER CONSTRUCTION
($ thousands)

Line	Particulars	Jan 1	Jan 31	Feb 28	Mar 31	Apr 30	May 31	June 30	July 31	Aug 31	Sep 30	Oct 31	Nov 30	Dec 31	12 Month Totals	13 Month Average
1.	Opening GPUC															
2.	Capital Expenditures															
3.	AFUDC															
4.	Transfers to GPIS															
5.	Closing GPUC		-	-	-	-	-	-	-	-	-	-	-	-		-

Appendix B
Invitation to Participate in the Settlement Negotiations

TransCanada PipeLines Limited
450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1
tel 403.920.2018
fax 403.920.2384
email stephen_clark@transcanada.com
web www.transcanada.com

September 4, 2007

TO: All Interested Parties

FROM: NOVA Gas Transmission Ltd.

RE: 2008-2010 Revenue Requirement Settlement Negotiations

On July 11, 2007, 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 three years pursuant to the Board's Negotiated Settlement Guidelines. The scope and term of the negotiation will be addressed by the parties to the negotiations. The Canadian Association of Petroleum Producers, the Industrial Gas Consumers Association of Alberta, and the Office of the Utilities Consumer Advocate filed letters with the Board supporting settlement discussions.

The Board approved NGTL's request to commence negotiations on July 31, 2007, providing that NGTL file its prospective forecast of its revenue requirement for the test years that it proposes to negotiate. NGTL filed an information package with the Board on August 23, 2007. NGTL has committed to 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 2007.

NGTL is inviting members of the Tolls, Tariff, Facilities, and Procedures Committee (TTFP), parties to NGTL's 2005 GRA Phase 2, 2005-2007 Revenue Requirement Settlement, 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. All parties to these discussions will be required to execute a Confidentiality Agreement.

NGTL will hold a meeting to provide additional details and to present background information on Thursday, September 13, 2007 from 1:30 to 3:30 pm in Room 214 (+15 level) at TransCanada Tower, 450 – 1st Street SW, Calgary.

Please respond to this invitation by notifying Tracy Batiuk at 403-920-5004 or by email at tracy_batiuk@transcanada.com by 4:00 pm on Monday, September 10, 2007 to ensure that all interested parties can be comfortably accommodated.

Regards,

(Original signed by)
Stephen Clark
Vice-President, Commercial West
Canadian Pipelines

cc: Alberta System Shippers
Parties to NGTL's 2005 GRA Phase 2
Parties to NGTL's 2005-2007 Revenue Requirement Settlement
Tolls Tariff, Facilities, and Procedures Committee
Alberta Energy and Utilities Board

Appendix C
Notice of Public Meeting

Notice of Public Meeting.

TransCanada PipeLines Limited's subsidiary **NOVA Gas Transmission Ltd. (NGTL)** is pleased to invite all interested and affected parties to a public information session to discuss a revenue settlement proposal for a term of up to three years, including 2008 to 2010.

When: Thursday, September 13, 2007
1:30 to 3:30 p.m

Where: Room 214 (Plus 15 level)
TransCanada Tower
450-1st Street SW
Calgary, Alberta

RSVP: Tracy Batiuk
Phone: 403 920.5004
E-mail: tracy_batiuk@transcanada.com

www.transcanada.com

TransCanada
In business to deliver

tmp.worldwide Integrated Marketing Communications
Artist: 2N
Production Only
Docket: 4528914
Date: Aug 28, 2007
Size: 4.56"
Proof: 1
1 of 2
Publication(s): CH EJ

Notice of Public Meeting.

TransCanada PipeLines Limited's subsidiary **NOVA Gas Transmission Ltd. (NGTL)** is pleased to invite all interested and affected parties to a public information session to discuss a revenue settlement proposal for a term of up to three years, including 2008 to 2010.

When: Thursday, September 13, 2007
1:30 to 3:30 p.m.

Where: Room 214 (Plus 15 level)
TransCanada Tower
450-1st Street SW
Calgary, Alberta

RSVP: Tracy Batiuk
Phone: 403.920.5004
E-mail: tracy_batiuk@transcanada.com

www.transcanada.com

TransCanada
In business to deliver

tmp.worldwide
Integrated Marketing Communications

Artist: 2N	
Production Only	
Docket: 4528914	
Date: Aug 28, 2007	
Size: 5.06"	
Proof: 1	
2 of 2	
Publication(s): CS ES	

Appendix D
List of Parties that Executed Confidentiality Agreements

List of Parties that Executed Confidentiality Agreements

Alberta Department of Energy
Alberta Utilities Commission (as observer only)
Alliance Pipeline Ltd.
ATCO Pipelines
Avista Corporation
BP Canada Energy Company
Canadian Association of Petroleum Producers
Canadian Natural Resources
Cargill Limited
Cascade Natural Gas
City of Medicine Hat
ConocoPhillips Canada Limited
Consumers' Coalition of Alberta
Coral Energy Canada Inc. (now Shell Energy North America (Canada) Inc.)
Devon Canada Corporation
Direct Energy Marketing Ltd.
EnCana Corporation
Export Users Group
ExxonMobil Canada
Harvest Operations Corp.
Husky Energy Marketing Inc.
Imperial Oil Resources
Industrial Gas Consumers Association of Alberta
Nexen Marketing
Northwest Natural Gas Company
NOVA Chemicals Corporation
NOVA Gas Transmission Ltd.
Office of the Utilities Consumer Advocate
Pacific Gas and Electric Company
Petro-Canada Oil and Gas
Puget Sound Energy
Shell Canada Energy
Suncor Energy Marketing Inc.
Talisman Energy Canada
Terasen Gas Inc.
UBS Commodities Canada Ltd.
Union Gas

Appendix E
Revenue Requirement Summary

Revenue Requirement Summary
($ Thousands)

Line No.	Description	Approved 2007	Settlement 2008
1	**Fixed Components**[1]		
2	Operating Costs, Return on Equity, and Income Taxes[2]	430,003	397,000
3	Depreciation	289,163	249,800
4	Total Fixed Components	719,166	646,800
5	**"Flow-through" Components**		
6	Debt	210,782	207,900
7	Property Taxes	85,600	98,100
8	Transportation by others	78,513	89,056
9	Regulatory hearing costs	1,057	3,006
10	Pipeline Integrity costs (expense)	30,959	37,729
11	Annual Foreign Exchange Amortization Amount	(1,512)	2,308
12	CO_2 Management Service costs (expense)	2,326	2,541
13	Repair and Overhaul[(2)]	10,643	23,631
14	FX on interest payments	1,000	(7,200)
15	Uninsured Losses	4,000	4,000
16	Emissions Compliance Costs		8,292
17	Total "Flow-through Components	423,368	469,363
18	Revenue Requirement net of deferrals	1,142,534	1,116,163
19	Deferral Accounts	(14,648)	29,038
20	Revenue Requirement	1,127,886	1,145,201

[1] Fixed costs components as per the 2008-2009 Revenue Requirement Settlement
[2] 2007 Operating Costs are based on the 2005-2007 Revenue Requirement Settlement less 2007 actual repair and overhaul costs

Appendix F
2007 Deferral Account Balances

2007 Deferral Account Balances
($ thousands)

Category	2007 Forecast	2007 Actual	Carrying Charges	Total Deferral Including Carrying Charges
Revenue	1,105,008	1,092,984	767	12,791
CO_2 Management Service	20,552	15,194	307	5,665
Flow-Through				
Pipeline Integrity Costs	30,959	30,362	(38)	(635)
Transportation by Others	78,513	83,509	323	5,319
Return on Equity	124,114	123,481	(43)	(676)
Debt Costs	210,782	211,152	23	393
Depreciation	289,163	289,011	(10)	(162)
Income Tax	109,532	109,260	(19)	(291)
Municipal Tax	85,600	87,310	110	1,820
Emission Compliance Costs	-	3,863	185	4,048
Total Flow-Through	928,663	937,948	531	9,816
Amortization of 50% of 2007 Severance Costs				766
Total			1,605	29,038

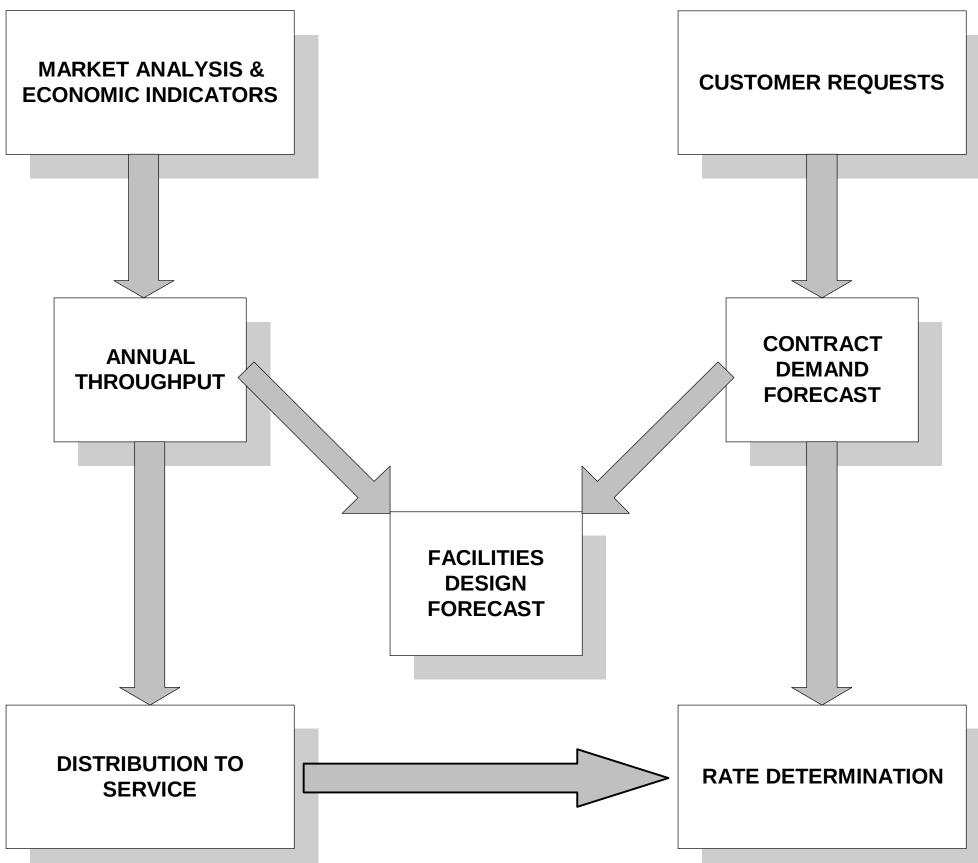
Appendix G
Contract Demand Quantity and Throughput

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 2008 rates. Figure 1.1 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 70 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 2008 average Receipt Point Contract Demand (which includes all Firm Services contracted at receipt points) is forecast to be 257.1 10^6m^3/d (9.1 Bcf/d). The 2008 average Export Delivery Point Contract Demand (which includes all Firm Services contracted at export delivery points) is forecast to be 8.46 PJ/d (7.95 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 flows 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 2008 Annual Throughput for the Alberta System is forecast to be 108.8 10^9m^3 (3,862 Bcf).

The forecasts of the 2008 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 2008. Quantities used in the forecast are based on information available as of the end of January 2008. 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 2008.

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 2008. 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 268.2 $10^6 m^3/d$ (9.5 Bcf/d) at the beginning of the year to 244.7 $10^6 m^3/d$ (8.7 Bcf/d) at the end of the 2008. The 2008 average Receipt Point Contract Demand, which is calculated as an average of twelve monthly forecasts, is forecast to be 257.1 $10^6 m^3/d$ (9.1 Bcf/d). The monthly forecast detail used to calculate the 2008 average Receipt Point Contract Demand forecast is shown in Table 1.2-2. Table 1.2-1 also includes figures for 2006 and 2007.

Table 1.2-1[1]
2006-2008 Firm Transportation Receipt Point Contract Demand

	2006 Actual		2007 Actual		2008 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	9.4	264.9	9.9	279.3	9.5	268.2
Adjustments:						
1. New Firm Transportation						
• Authorized	2.2	62.3	0.9	26.3	0.1	2.7
• Estimated	0.0	0.0	0.0	0.0	1.0	27.8
• Total new	2.2	62.3	0.9	26.3	1.1	30.4
2. Non-Renewals (actual + projected)	(1.7)	(47.8)	(1.3)	(37.4)	(1.9)	(54.0)
End of Year	9.9	279.3	9.5	268.2	8.7	244.7
Average Monthly Quantity	**9.9**	**278.2**	**9.9**	**278.0**	**9.1**	**257.1**

1. Numbers may not add due to rounding

Table 1.2-2[1]

2008 Monthly Firm Transportation Receipt Point Contract Demand

(Bcf/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Previous Month-End	9.52	9.47	9.39	8.86	8.95	9.00	9.01	8.97	8.92	8.95	8.57	8.84
Estimated Incremental Receipt	0.07	0.01	0.01	0.26	0.16	0.05	0.02	0.03	0.08	0.04	0.29	0.06
Start of Month	9.59	9.49	9.40	9.12	9.10	9.05	9.02	9.00	9.00	8.99	8.86	8.90
Less Non-Renewals	0.12	0.10	0.53	0.18	0.10	0.04	0.05	0.09	0.04	0.42	0.03	0.21
End of Month	9.47	9.39	8.86	8.95	9.00	9.01	8.97	8.92	8.95	8.57	8.84	8.68

Monthly Average (Start of Month): 9.13

(10^6 m^3/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Previous Month-End	268.2	266.9	264.4	249.7	252.1	253.6	253.7	252.7	251.3	252.2	241.6	249.0
Estimated Incremental Receipt	2.0	0.4	0.3	7.3	4.4	1.4	0.5	0.9	2.2	1.1	8.1	1.7
Start of Month	270.3	267.3	264.7	257.0	256.5	255.0	254.3	253.7	253.4	253.3	249.7	250.7
Less Non-Renewals	3.4	2.9	15.0	4.9	2.9	1.2	1.5	2.4	1.2	11.7	0.7	6.0
End of Month	266.9	264.4	249.7	252.1	253.6	253.7	252.7	251.3	252.2	241.6	249.0	244.7

Monthly Average (Start of Month): 257.1

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 2007/08 and 2008/09 Gas Years, and adjustments for any new and expiring Contract Demand forecast to occur during 2008. Components of the total 2008 Export Delivery Point Contract Demand of 8.46 PJ/d (7.95 Bcf/d) are shown in Table 1.2-3. Figures are also included for 2006 and 2007. The monthly forecast detail used to calculate the 2008 average Export Delivery Point Contract Demand forecast is shown in Table 1.2-4.

Table 1.2-3[1]
2006-2008 Firm Transportation Export Delivery Point Contract Demand[2]

	2006 Actual		2007 Actual		2008 Forecast	
Export Delivery Point	**Bcf/d**	**$10^6 m^3/d$**	**Bcf/d**	**PJ/d**	**Bcf/d**	**PJ/d**
Empress	4.38	123.4	4.34	4.63	3.77	4.02
McNeill	1.81	51.1	1.82	1.94	1.65	1.76
Alberta/B.C.	2.67	75.3	2.41	2.57	2.44	2.60
Other Borders	0.04	1.2	0.07	0.07	0.09	0.09
Total Average Quantity	**8.91**	**250.9**	**8.65**	**9.21**	**7.95**	**8.46**

1. Numbers may not add due to rounding
2. Values include FT-D, FT-DW, LRS and STFT

Table 1.2-4[1]

2008 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	7.43	7.59	7.04	6.13	6.13	6.13	6.11	6.11	6.11	6.11	3.94	5.83
Estimated Incremental FT-D	1.65	1.17	1.17	1.43	1.33	1.36	1.51	1.61	1.34	1.49	4.07	2.57
Start of Month	9.08	8.76	8.21	7.56	7.46	7.49	7.62	7.72	7.46	7.60	8.01	8.41
Less Non-Renewals	1.49	1.72	2.09	1.43	1.33	1.38	1.51	1.61	1.35	3.66	2.18	2.98
End of Month	7.59	7.04	6.13	6.13	6.13	6.11	6.11	6.11	6.11	3.94	5.83	5.43

Monthly Average (Start of Month): 7.95

(PJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Previous Month-End	7.92	8.08	7.50	6.52	6.52	6.52	6.51	6.51	6.51	6.51	4.20	6.21
Estimated Incremental FT-D	1.75	1.25	1.25	1.52	1.42	1.45	1.61	1.71	1.43	1.59	4.34	2.74
Start of Month	9.67	9.33	8.75	8.05	7.94	7.97	8.12	8.22	7.94	8.09	8.53	8.96
Less Non-Renewals	1.59	1.84	2.22	1.52	1.42	1.47	1.61	1.71	1.43	3.90	2.32	3.17
End of Month	8.08	7.50	6.52	6.52	6.52	6.51	6.51	6.51	6.51	4.20	6.21	5.78

Monthly Average (Start of Month): 8.46

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-BC border, which connects with Foothills Pipe Lines (South B.C.) Ltd. and supplies southern B.C. markets, and the Pacific Northwest and California markets through TransCanada PipeLines Limited's Gas Transmission Northwest ("GTN") pipeline system;
- Unity and Cold Lake borders, which connect with TransGas Limited and supply the Saskatchewan market;
- Gordondale and Boundary Lake borders, which connect with the Spectra Energy 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 the 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 for 2008 are forecast to decrease 4.9% from the actual for 2007.

Table 1.3-1[1]
Alberta System Throughput Forecast

	2006 Actual		2007 Actual		2008 Forecast	
Delivery Point	**Bcf**	**10^9m^3**	**Bcf**	**10^9m^3**	**Bcf**	**10^9m^3**
Empress	1,924	54.2	1,835	51.7	1,581	44.5
McNeill	703	19.8	685	19.3	665	18.7
Alberta/B.C.	712	20.1	768	21.6	719	20.2
Other Borders	18	0.5	21	0.6	12	0.3
Sub-Total Borders	**3,357**	**94.6**	**3,308**	**93.2**	**2,976**	**83.8**
Intra-Alberta	685	19.3	711	20.0	849	23.9
Total System (excl. Fuel)	**4,042**	**113.9**	**4,019**	**113.2**	**3,825**	**107.8**
Fuel	36	1.0	40	1.1	37	1.0
Total System (incl. Fuel)	**4,077**	**114.9**	**4,060**	**114.4**	**3,862**	**108.8**

1. Numbers may not add due to rounding.

The 2008 throughput at Export Delivery Points is forecast to decrease by 10.0% from the actual for 2007, while throughput at Alberta Delivery Points is forecast to increase by 19.4%.

1.3.3 Distribution of 2008 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 2008 calendar year.

Table 1.3-2[1]
2008 Receipt Throughput by Service

Throughput Service Category	Bcf	10^9m^3	Percent of Annual Throughput
Firm Transportation Receipts[2]	2,703	76.2	70.0 %
Interruptible Transportation Receipts	729	20.5	18.9%
Other Transportation Services[3]	384	10.8	9.9%
Total Services	3,815	107.5	98.8%
Net Receipts from Storage	47	1.3	1.2%
Total Throughput	**3,862**	**108.8**	**100%**

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

Table 1.3-3[1]
2008 Delivery Throughput by Service

Throughput Service Category	PJ	$10^9 m^3$	Percent of Annual Throughput
Firm Transportation Deliveries	3,052	80.9	74.4%
Interruptible Transportation Deliveries [2]	104	3.0	2.5%
Firm Transportation Alberta Deliveries [3]	904	23.9	22.1%
Total Delivery Services	4,061	107.8	99.0%
Fuel	39	1.0	1.0%
Total Throughput	**4,100**	**108.8**	**100%**

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

Appendix H
2008 Rates, Tolls and Charges

1.0 2008 RATES TOLLS AND CHARGES

1.1 RATES, TOLLS AND CHARGES SUMMARY

This Appendix contains the rates, tolls and charges for all services for 2008. NGTL calculated rates in accordance with the rate design approved by the EUB in Decision 2006-010, the contract demand and throughput quantities outlined in Appendix G, and the 2008 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.

As indicated in Section 3, the rates provided in Figure 1.1-1 are within 1% of the 2008 interim rates. Since the effect on rates is immaterial, NGTL is requesting that the 2008 interim rates be made final for the period January 1, 2008 to April 30, 2008 and the interim rates become final rates for the period May 1, 2008 to December 31, 2008.

Table 1.1-1 and Attachments 1 and 2 contain the 2008 Rates, Tolls and Charges, including updates made to OS charges to reflect revised contracts. The 2008 average FT-R rate and FT-D rate is 15.5 cents/mcf/d.

Figure 1.1-1 - 2008 Rate Calculation

TOTAL REVENUE REQUIREMENT	$ 1,145.2	Million

MINUS

NON TRANSPORTATION REVENUE	$Millions
FCS	$ 8.1
OS	$ 1.0
PT	$ 0.0
CO_2	$ 11.8
Calpine Credit	$ 32.7
Total	$ 53.6

EQUALS

TRANSPORTATION REVENUE REQUIREMENT	$ 1,091.6	Million

MINUS

LRS REVENUE*	(Bcf/d)	(10^6m^3/d)	$Millions
LRS-1	0.63	17.69	$ 43.8
LRS-2	0.05	1.33	$ 0.7
LRS-3	0.05	1.41	$ 2.3
Total	0.72	20.42	$ 46.8

* Revenues adjusted to account for NGTL's contribution.

MINUS

OTHER TRANSPORTATION REVENUE	(TJ/d)	(Bcf/d)	(10^6m^3/d)	$Millions
IT-D*	284.93	0.29	8.14	$ 18.1
STFT	1,875.04	1.76	49.60	$ 100.0
IT-R		1.99	56.09	$ 131.6
FT-P		0.32	9.12	$ 18.4
FT-RN		0.03	0.91	$ 2.1
FT-DW	13.82	0.01	0.37	$ 0.9
FT-A		1.53	43.00	$ 7.5
Total	2,173.78	5.94	167.23	$ 278.6

* Revenues adjusted to account for Alternate Access

EQUALS

FIRM TRANSPORTATION REVENUE REQUIREMENT	$ 766.2	Million

NOTE: Numbers may not add due to rounding

Figure 1.1-1 cont. - 2008 Rate Calculation

FIRM TRANSPORTATION REVENUE REQUIREMENT $ 766.2 Million

DIVIDED BY

CONTRACT DEMAND*	(TJ/d)	(Bcf)	($10^6 m^3/d$)
Delivery	5,802.56	1,994.16	153.5
Receipt		2,944.65	226.7
Total		4,938.82	380.2

* All export delivery contracts have been converted to volume using a heat value of 37.8 mj/m^3

EQUALS

FIRM TRANSPORTATION RATE	($/GJ/mth)	($/Mcf/d)	($/$10^3 m^3$/mth)
	4.44	0.155	167.94

MULTIPLIED BY

RECEIPT CONTRACT DEMAND

(Bcf)	($10^6 m^3/d$)
2,944.65	226.7

EQUALS

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT
$ 456.8 Million

MULTIPLIED BY

DELIVERY CONTRACT DEMAND

(TJ/d)	(Bcf)	($10^6 m^3/d$)
5,802.56	1,994.16	153.5

EQUALS

FIRM TRANSPORTATION DELIVERY REVENUE REQUIREMENT
$ 309.4 Million

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT $ 456.8 Million

ALLOCATED TO EACH RECEIPT POINT

RECEIPT TRANSPORTATION REVENUE

	Revenue ($Millions)	Volumes (Bcf/d)	Volumes ($10^6 m^3/d$)	FT-R Average Rate ($/Mcf/d)	FT-R Average Rate ($/$10^3 m^3$/mth)
1 Year Receipt	$ -	0.00	0.00	0.163	176.34
3 Year Receipt	$ 456.8	8.05	226.67	0.155	167.94
5 Year Receipt	$ -	0.00	0.00	0.147	159.54
Firm Receipt	$ 456.8	8.05	226.67		
Floor Rate				0.075	81.34
Ceiling Rate				0.235	254.54

NOTE: Numbers may not add due to rounding

TABLE 1.1-1 2008 RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $168.24/$10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D	FT-D Demand Rate per month $ 4.45/GJ
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate
6. Rate Schedule FT-A	FT-A Commodity Rate $ 0.48/10^3m^3
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month
8. Rate Schedule LRS	<u>Contract Term</u> — <u>Effective LRS Rate ($/$10^3m^3$/day)</u> 1-5 years — 10.08 6-10 years — 8.42 15 years — 7.55 20 years — 6.71
9. Rate Schedule LRS-2	LRS-2 Rate per month $50,000
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month $129.55/$10^3m^3$
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 $ 0.1606/GJ
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
14. Rate Schedule PT	<u>Schedule No</u> — <u>PT Rate</u> — <u>PT Gas Rate</u> 9006-01000-0 — $ 67.22/d — 1.0 10^3m^3/d
15. Rate Schedule OS	<u>Schedule No.</u> — <u>Charge</u> 2003034359 — $ 899.00 / month 2008315264 — $ 69.00 / month 2008315632 — $ 56.00 / month 2008316530 — $ 8.00 / month 2008316531 — $ 5.00 / month 2008315263 — $ 6.00 / month 2008316532 — $ 52.00 / month 2008315634 — $ 7.00 / month 2007262175 — $ 438.00 / month 2008315627 — $ 1,831.00 / month 2008315265 — $ 17.00 / month 2008315631 — $ 49.00 / month 2008315262 — $ 163.00 / month 2008315630 — $ 71.00 / month 2008315628 — $ 191.00 / month 2008316529 — $ 8.00 / month 2008315633 — $ 2.00 / month 2008315629 — $ 2.00 / month 2003004522 — $ 83,333.00 / month
16. Rate Schedule CO_2	<u>Tier</u> — <u>CO_2 Rate ($/$10^3m^3$)</u> 1 — 630.10 2 — 503.07 3 — 349.65

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)
1337	ABEE	254.84	280.32	9.61
1631	ACADIA EAST	122.14	134.35	4.61
1613	ACADIA NORTH	122.77	135.05	4.63
1424	ACADIA VALLEY	174.14	191.55	6.57
1890	ACADIA VALLEY WEST	81.64	89.80	3.08
3880	AECO INTERCONNECTION	81.64	89.80	3.08
1526	AKUINU RIVER	254.84	280.32	9.61
1681	AKUINU RIVER W.	254.84	280.32	9.61
3868	ALBERTA MONTANA BORDER	99.78	109.76	3.76
2000	ALBERTA-B.C. BDR (CHART ACC	81.64	89.80	3.08
2109	ALDER FLATS	101.19	111.31	3.82
2200	ALDER FLATS S.	99.32	109.25	3.74
1075	ALDERSON	86.93	95.62	3.28
1208	ALDERSON NORTH	88.89	97.78	3.35
1103	ALDERSON SOUTH	86.97	95.67	3.28
5026	ALGAR LAKE	254.84	280.32	9.61
1851	AMISK SOUTH	242.57	266.83	9.15
1469	ANDREW	176.09	193.70	6.64
1573	ANSELL	137.74	151.51	5.19
2136	ANTE CREEK S.	254.84	280.32	9.61
1567	ARMENA	254.84	280.32	9.61
1770	ARMSTRONG LAKE	254.84	280.32	9.61
2708	ASSUMPTION	254.84	280.32	9.61
2734	ASSUMPTION #2	254.84	280.32	9.61
1326	ATHABASCA	254.84	280.32	9.61
1368	ATHABASCA EAST	245.63	270.19	9.26
1009	ATLEE-BUFFALO	81.64	89.80	3.08
1116	ATLEE-BUFFALO E	81.64	89.80	3.08
1098	ATLEE-BUFFALO S	81.64	89.80	3.08
1297	ATMORE	231.27	254.40	8.72
1792	ATUSIS CREEK E	81.64	89.80	3.08
3943	ATUSIS CREEK INTERCONNECTI	81.64	89.80	3.08
1275	BADGER EAST	81.64	89.80	3.08
1649	BADGER NORTH	99.77	109.75	3.76
2744	BALLATER #2	254.84	280.32	9.61
1100	BANTRY	81.64	89.80	3.08
1296	BANTRY N.E.	81.64	89.80	3.08
1181	BANTRY N.W.	81.64	89.80	3.08
1122	BANTRY NORTH	81.64	89.80	3.08
1398	BAPTISTE	254.84	280.32	9.61
1339	BAPTISTE SOUTH	254.84	280.32	9.61
1497	BARICH	254.84	280.32	9.61
1329	BASHAW	127.77	140.55	4.82
1393	BASHAW B	127.82	140.60	4.82
1330	BASSANO SOUTH	99.48	109.43	3.75
2761	BASSET LAKE	254.84	280.32	9.61
2085	BASSET LAKE S.	254.84	280.32	9.61
2066	BASSET LAKE W.	254.84	280.32	9.61
1197	BAXTER LAKE	254.84	280.32	9.61
1334	BAXTER LAKE B	254.84	280.32	9.61
1382	BAXTER LAKE NW	254.84	280.32	9.61
1231	BAXTER LAKE S.	254.84	280.32	9.61
1198	BAXTER LAKE W.	254.84	280.32	9.61
2143	BAY TREE	254.84	280.32	9.61
2222	BEAR CANYON W.	240.25	264.28	9.06
2132	BEAR RIVER	254.84	280.32	9.61
1459	BEAUVALLON	254.84	280.32	9.61

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)
1089	BELLIS	184.71	203.18	6.96
1675	BELLIS SOUTH	182.90	201.19	6.90
2043	BELLOY	254.84	280.32	9.61
2105	BELLOY WEST	209.58	230.54	7.90
1720	BELTZ LAKE	145.58	160.14	5.49
1264	BENALTO WEST	132.42	145.66	4.99
2177	BENBOW SOUTH	181.98	200.18	6.86
1274	BENTON WEST	108.41	119.25	4.09
1604	BERRY CREEK S.	121.30	133.43	4.57
1085	BERRY-CAROLSIDE	81.64	89.80	3.08
1157	BIG BEND	254.84	280.32	9.61
1225	BIG BEND EAST	254.84	280.32	9.61
3933	BIG EDDY INTERCONNECTION	134.23	147.65	5.06
2175	BIG PRAIRIE	254.84	280.32	9.61
1870	BIG VALLEY	213.41	234.75	8.05
1835	BIGKNIFE CREEK	124.36	136.80	4.69
2176	BIGORAY RIVER	154.07	169.48	5.81
1002	BINDLOSS N. #1	81.64	89.80	3.08
1001	BINDLOSS SOUTH	81.64	89.80	3.08
1474	BINDLOSS WEST	161.21	177.33	6.08
3446	BITTERN LAKE SL	254.84	280.32	9.61
1616	BLOOD IND CK E.	93.28	102.61	3.52
1505	BLOOD INDIAN CK	81.64	89.80	3.08
1779	BLOOR LAKE	203.00	223.30	7.65
1511	BLUE JAY	254.84	280.32	9.61
2704	BLUE RAPIDS	107.57	118.33	4.06
3471	BLUE RIDGE E SL	208.00	228.80	7.84
2119	BLUEBERRY HILL	254.84	280.32	9.61
1242	BODO WEST	174.60	192.06	6.58
2773	BOGGY HALL	105.01	115.51	3.96
1590	BOHN LAKE	254.84	280.32	9.61
5012	BOIVIN CREEK	254.84	280.32	9.61
1778	BOLLOQUE #2	254.84	280.32	9.61
1290	BOLLOQUE SOUTH	254.84	280.32	9.61
1401	BONAR WEST	81.64	89.80	3.08
1796	BONNIE GLEN	176.39	194.03	6.65
1660	BONNYVILLE	254.84	280.32	9.61
2709	BOOTIS HILL	254.84	280.32	9.61
2117	BOTHA	254.84	280.32	9.61
2182	BOTHA EAST	254.84	280.32	9.61
2217	BOTHA WEST	254.84	280.32	9.61
2220	BOULDER CREEK	254.84	280.32	9.61
3001	BOUNDARY LAKE S	241.14	265.25	9.09
3002	BOUNDARY LK BDR	243.70	268.07	9.19
1318	BOWELL SOUTH	110.94	122.03	4.18
1849	BOWELL SOUTH #2	110.94	122.03	4.18
1216	BOWMANTON	120.83	132.91	4.56
1842	BOWMANTON EAST	109.56	120.52	4.13
1204	BOWMANTON SOUTH	100.32	110.35	3.78
1237	BOWMANTON WEST	193.98	213.38	7.31
2138	BOYER EAST	254.84	280.32	9.61
1703	BOYLE WEST	202.94	223.23	7.65
1947	BRAZEAU - BRAZEAU EAST SUM	128.12	140.93	4.83
1096	BRAZEAU SOUTH	123.32	135.65	4.65
1619	BRIGGS	111.19	122.31	4.19
2721	BROWNVALE NORTH	200.35	220.39	7.55
2364	BROWNVALE SALES	250.30	275.33	9.44

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)
1168	BRUCE	128.86	141.75	4.86
1409	BULLPOUND	115.50	127.05	4.35
1350	BULLPOUND SOUTH	191.67	210.84	7.23
1555	BULLSHEAD	160.07	176.08	6.04
6004	BURNT PINE	254.84	280.32	9.61
2118	BURNT RIVER	212.32	233.55	8.01
2032	BURNT TIMBER	94.58	104.04	3.57
2181	BUTTE	82.51	90.76	3.11
1561	BYEMOOR	148.04	162.84	5.58
1725	CADOGAN	254.84	280.32	9.61
2221	CADOTTE RIVER	254.84	280.32	9.61
2738	CALAIS	194.22	213.64	7.32
1373	CALLING LAKE	254.84	280.32	9.61
1522	CALLING LAKE E.	254.84	280.32	9.61
6019	CALLING LAKE SE (SIMMONS)	249.86	274.85	9.42
1443	CALLING LAKE W.	206.84	227.52	7.80
1676	CALLING LK N.	234.48	257.93	8.84
1387	CALLING LK S.	242.02	266.22	9.13
2743	CALLUM CREEK	81.64	89.80	3.08
1651	CAMROSE CREEK	254.84	280.32	9.61
1805	CANOE LAKE	254.84	280.32	9.61
3866	CARBON INTERCONNECTION	81.64	89.80	3.08
1622	CARBON WEST	82.35	90.59	3.11
1692	CARIBOU LAKE	254.84	280.32	9.61
3893	CARROT CREEK #3893 INTERCO	124.43	136.87	4.69
1840	CARSELAND RECEIPT	81.64	89.80	3.08
2018	CARSON CREEK	209.74	230.71	7.91
2188	CARSON CREEK E.	249.85	274.84	9.42
3330	CARSTAIRS INTERCONNECTION	82.05	90.26	3.09
1491	CASLAN	254.84	280.32	9.61
1492	CASLAN EAST	254.84	280.32	9.61
1315	CASSILS	105.85	116.44	3.99
1397	CASTOR	167.89	184.68	6.33
2786	CATTAIL LK SOUTH	177.25	194.98	6.68
1737	CAVALIER	126.73	139.40	4.78
1228	CAVENDISH SOUTH	84.25	92.68	3.18
2768	CECILIA	145.01	159.51	5.47
1863	CESSFD-BURF W#2	107.01	117.71	4.03
1025	CESSFORD EAST	83.71	92.08	3.16
1152	CESSFORD N.E.	81.64	89.80	3.08
1145	CESSFORD NORTH	81.64	89.80	3.08
1312	CESSFORD SOUTH	81.64	89.80	3.08
1086	CESSFORD W GAGE	81.64	89.80	3.08
1004	CESSFORD WARDLO	81.64	89.80	3.08
1012	CESSFORD WEST	81.64	89.80	3.08
1060	CESSFORD-BUR #2	93.23	102.55	3.52
1027	CESSFORD-BURF W	107.01	117.71	4.03
3907	CHANCELLOR INTERCONNECTI(	81.64	89.80	3.08
1876	CHAPEL ROCK	81.64	89.80	3.08
1196	CHAUVIN	254.84	280.32	9.61
1666	CHEECHAM	254.84	280.32	9.61
1708	CHELSEA CREEK	254.84	280.32	9.61
1680	CHERRY GROVE E.	254.84	280.32	9.61
2705	CHESTER CREEK	254.84	280.32	9.61
2789	CHICKADEE CK #2	182.18	200.40	6.87
2286	CHICKADEE CK W.	254.84	280.32	9.61
1034	CHIGWELL	171.08	188.19	6.45

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)
1040	CHIGWELL EAST	161.15	177.27	6.08
2108	CHINCHAGA	254.84	280.32	9.61
2266	CHINCHAGA WEST	254.84	280.32	9.61
1221	CHINOOK-CEREAL	139.85	153.84	5.27
5409	CHIP LAKE	124.55	137.01	4.70
3885	CHIP LAKE JCT	124.43	136.87	4.69
1609	CHISHOLM MILL W	254.84	280.32	9.61
1434	CHISHOLM MILLS	254.84	280.32	9.61
1322	CHOICE	254.84	280.32	9.61
1323	CHOICE B	254.84	280.32	9.61
1712	CHRISTINA LAKE	254.84	280.32	9.61
1535	CLANDONALD	254.84	280.32	9.61
2070	CLARK LAKE	164.19	180.61	6.19
2063	CLEAR HILLS	254.26	279.69	9.59
2250	CLEAR HILLS N.	213.26	234.59	8.04
2764	CLEAR PRAIRIE	254.84	280.32	9.61
3008	CLEARDALE	254.84	280.32	9.61
1454	CLYDE	254.84	280.32	9.61
1803	CLYDE NORTH	254.84	280.32	9.61
6007	CLYDEN	254.84	280.32	9.61
3883	COALDALE JCT	88.77	97.65	3.35
5402	COALDALE S. B	114.74	126.21	4.33
3884	COALDALE S. JCT	88.77	97.65	3.35
1612	COATES LAKE	227.81	250.59	8.59
2735	CODESA	254.84	280.32	9.61
2152	CODNER	128.69	141.56	4.85
1417	COLD LAKE BDR	254.84	280.32	9.61
2003	COLEMAN	81.64	89.80	3.08
3052	COLEMAN SALES	81.64	89.80	3.08
2794	COLT	146.80	161.48	5.54
1624	CONKLIN	254.84	280.32	9.61
1634	CONKLIN WEST	254.84	280.32	9.61
1713	CONN LAKE	254.84	280.32	9.61
1635	CONTRACOSTA E.	216.43	238.07	8.16
1614	CONTRACOSTA LK	162.42	178.66	6.12
2736	COPTON CREEK	234.45	257.90	8.84
1763	CORNER LAKE #2	254.84	280.32	9.61
1697	CORRIGALL LAKE	254.84	280.32	9.61
1028	COUNTESS	84.46	92.91	3.18
1015	COUNTESS MAKEPEACE	91.39	100.53	3.45
2296	COUNTESS S. #2	81.64	89.80	3.08
1287	COUNTESS WEST	147.23	161.95	5.55
1963	COUSINS B & C SALES (SUMMAF	130.20	143.22	4.91
1433	COUSINS WEST	130.48	143.53	4.92
1088	CRAIGEND	254.84	280.32	9.61
1112	CRAIGEND EAST	254.84	280.32	9.61
1320	CRAIGEND NORTH	254.84	280.32	9.61
1148	CRAIGEND SOUTH	254.84	280.32	9.61
1541	CRAIGMYLE	242.25	266.48	9.13
1583	CRAIGMYLE EAST	254.84	280.32	9.61
1686	CRAMMOND	87.38	96.12	3.29
2749	CRANBERRY LK #2	254.84	280.32	9.61
3105	CRANBERRY LK SL	254.84	280.32	9.61
1701	CROOKED LK S.	170.40	187.44	6.42
2724	CROOKED LK W.	157.31	173.04	5.93
2008	CROSSFIELD	82.05	90.26	3.09
3897	CROSSFIELD EAST INTERCONNI	81.64	89.80	3.08

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 ($\$/10^3m^3$)
1773	CROW LAKE SOUTH	254.84	280.32	9.61
2731	CROWELL	254.84	280.32	9.61
2718	CULP #2	254.84	280.32	9.61
1807	CULP NORTH	254.84	280.32	9.61
1489	CUTBANK RIVER	235.27	258.80	8.87
1738	DANCING LAKE	254.84	280.32	9.61
1279	DAPP EAST	254.84	280.32	9.61
2289	DARLING CREEK	254.84	280.32	9.61
1864	DAVEY LAKE	85.76	94.34	3.23
1529	DAYSLAND	136.01	149.61	5.13
2233	DEBOLT	250.63	275.69	9.45
1760	DECRENE EAST	254.84	280.32	9.61
1646	DECRENE NORTH	254.84	280.32	9.61
3888	DEEP VALLEY CREEK INTERCON	218.04	239.84	8.22
2244	DEEP VLLY CRK S	153.44	168.78	5.79
1539	DELIA	192.25	211.48	7.25
1476	DEMMITT	239.34	263.27	9.02
1734	DEVENISH SOUTH	254.84	280.32	9.61
1733	DEVENISH WEST	254.84	280.32	9.61
1185	DISMAL CREEK	135.98	149.58	5.13
2210	DIXONVILLE N #2	211.23	232.35	7.96
2110	DIXONVILLE N.	254.84	280.32	9.61
2197	DOE CREEK	254.84	280.32	9.61
2712	DOE CREEK SOUTH	254.84	280.32	9.61
2776	DOIG RIVER	248.20	273.02	9.36
1147	DONALDA	232.30	255.53	8.76
1520	DONATVILLE	243.40	267.74	9.18
2254	DORIS CREEK N.	254.84	280.32	9.61
1236	DOROTHY	166.56	183.22	6.28
1818	DOWLING	93.23	102.55	3.52
2719	DREAU	254.84	280.32	9.61
1689	DROPOFF CREEK	254.84	280.32	9.61
1475	DUHAMEL	254.84	280.32	9.61
5022	DUNKIRK RIVER	254.84	280.32	9.61
1220	DUNMORE	140.89	154.98	5.31
2044	DUNVEGAN	222.57	244.83	8.39
2716	DUNVEGAN W. #2	254.84	280.32	9.61
2084	DUNVEGAN WEST	254.84	280.32	9.61
1877	DUVERNAY	186.64	205.30	7.04
3062	E. CALGARY B SL	83.36	91.70	3.14
2081	EAGLE HILL	131.87	145.06	4.97
2097	EAGLESHAM	187.63	206.39	7.07
2787	EAGLESHAM SOUTH	186.57	205.23	7.03
2007	EAST CALGARY	83.33	91.66	3.14
1568	EDBERG	212.21	233.43	8.00
1265	EDGERTON	254.84	280.32	9.61
1266	EDGERTON WEST	254.84	280.32	9.61
1064	EDSON	132.22	145.44	4.99
1213	EDWAND	205.86	226.45	7.76
2760	EKWAN	254.84	280.32	9.61
1715	ELINOR LAKE	254.84	280.32	9.61
1742	ELINOR LAKE E.	254.84	280.32	9.61
1558	ELK RIVER SOUTH	123.99	136.39	4.68
1615	ELMWORTH HIGH	189.54	208.49	7.15
1862	ELNORA EAST #2	215.68	237.25	8.13
1958	EMPRESS BORDER	81.64	89.80	3.08
1024	ENCHANT	110.92	122.01	4.18

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)
1507	ENDIANG	95.34	104.87	3.59
1074	EQUITY	116.86	128.55	4.41
1359	EQUITY B	133.38	146.72	5.03
1586	EQUITY EAST	136.13	149.74	5.13
1232	ERSKINE NORTH	178.73	196.60	6.74
1746	ESTRIDGE LAKE	254.84	280.32	9.61
2049	ETA LAKE	129.65	142.62	4.89
1547	ETZIKOM A	254.84	280.32	9.61
1548	ETZIKOM B	254.84	280.32	9.61
1557	ETZIKOM D	254.84	280.32	9.61
1677	FAIRYDELL CREEK	254.84	280.32	9.61
3112	FALHER SALES	254.84	280.32	9.61
2729	FARIA	254.84	280.32	9.61
1891	FAWCETT R W #3	254.84	280.32	9.61
1375	FAWCETT RIVER	254.84	280.32	9.61
1753	FAWCETT RVR N.	254.84	280.32	9.61
1868	FERINTOSH SOUTH	235.31	258.84	8.87
1659	FERINTOSH WEST	254.84	280.32	9.61
2016	FERRIER	129.60	142.56	4.89
1101	FERRIER NORTH	123.31	135.64	4.65
2115	FERRIER SOUTH A	129.68	142.65	4.89
1111	FERRIER SOUTH B	134.54	147.99	5.07
1087	FIGURE LAKE	240.21	264.23	9.06
1300	FITZALLAN SOUTH	203.76	224.14	7.68
1095	FLAT LAKE	254.84	280.32	9.61
1302	FLAT LAKE NORTH	254.84	280.32	9.61
1632	FOISY	203.55	223.91	7.67
2251	FONTAS RIVER	254.84	280.32	9.61
3304	FORESTBURG SLS	112.82	124.10	4.25
1376	FORSHEE	111.42	122.56	4.20
1602	FORT KENT	254.84	280.32	9.61
2199	FOULWATER CREEK	254.84	280.32	9.61
2103	FOURTH CREEK	254.84	280.32	9.61
2198	FOURTH CREEK W.	254.84	280.32	9.61
2268	FRAKES FLATS	194.84	214.32	7.35
2772	FREEMAN RIVER	254.84	280.32	9.61
1875	GALT ISLAND	108.12	118.93	4.08
2079	GARRINGTON EAST	125.25	137.78	4.72
1623	GATINE	81.64	89.80	3.08
1358	GAYFORD	81.64	89.80	3.08
1435	GEM SOUTH	81.64	89.80	3.08
1490	GEM WEST	81.64	89.80	3.08
1073	GHOSTPINE	98.30	108.13	3.71
1617	GHOSTPINE B	101.78	111.96	3.84
1037	GILBY #2	120.15	132.17	4.53
1084	GILBY SOUTH PAC	120.15	132.17	4.53
2037	GILBY WEST	133.09	146.40	5.02
2722	GILMORE LAKE	215.12	236.63	8.11
3894	GILT EDGE WEST INTERCONNE(	254.84	280.32	9.61
1480	GLEICHEN	183.39	201.73	6.91
1456	GLENDON	254.84	280.32	9.61
2031	GOLD CREEK	172.10	189.31	6.49
1452	GOODFARE	222.27	244.50	8.38
1504	GOODRIDGE	254.84	280.32	9.61
1783	GOODRIDGE NORTH	254.84	280.32	9.61
1798	GOOSEQUILL	223.06	245.37	8.41
1880	GOOSEQUILL WEST	117.37	129.11	4.43

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)
3886	GORDONDALE BORDER	234.28	257.71	8.83
1560	GOUGH LAKE	104.00	114.40	3.92
1448	GRACE CREEK	132.59	145.85	5.00
2771	GRACE CREEK STH	114.17	125.59	4.30
1482	GRAHAM	254.84	280.32	9.61
1352	GRAINGER	81.64	89.80	3.08
2129	GRANADA	154.17	169.59	5.81
3424	GRANDE CENTRE S	254.84	280.32	9.61
5005	GRANOR	254.84	280.32	9.61
1093	GREENCOURT	226.04	248.64	8.52
1267	GREGORY	97.76	107.54	3.69
1365	GREGORY N.E.	89.00	97.90	3.36
1259	GREGORY WEST	81.64	89.80	3.08
5025	GREW LAKE	254.84	280.32	9.61
5028	GREW LK EAST	254.84	280.32	9.61
1647	GRIST LAKE	254.84	280.32	9.61
2770	GRIZZLY	173.60	190.96	6.55
1538	HACKETT	254.84	280.32	9.61
1722	HACKETT WEST	254.84	280.32	9.61
1576	HADDOCK	162.72	178.99	6.14
1589	HADDOCK NORTH	168.23	185.05	6.34
1636	HADDOCK SOUTH	192.74	212.01	7.27
2086	HAIG RIVER	254.84	280.32	9.61
2064	HAIG RIVER EAST	254.84	280.32	9.61
2127	HAIG RIVER N.	254.84	280.32	9.61
1230	HAIRY HILL	193.42	212.76	7.29
1391	HALKIRK	127.92	140.71	4.82
1834	HALKIRK NORTH#2	107.56	118.32	4.06
2797	HAMBURG	254.84	280.32	9.61
3915	HAMILTON LAKE SUMMARY	242.97	267.27	9.16
1291	HAMLIN	254.84	280.32	9.61
6003	HANGINGSTONE	254.84	280.32	9.61
1182	HANNA	94.38	103.82	3.56
1444	HARDISTY	235.51	259.06	8.88
1166	HARMATTAN-ELKTN	86.45	95.10	3.26
2145	HARO RIVER N.	254.84	280.32	9.61
2766	HARPER CREEK	207.78	228.56	7.83
1850	HARTELL SOUTH	81.64	89.80	3.08
1709	HASTINGS COULEE	169.10	186.01	6.38
1418	HATTIE LAKE N.	254.84	280.32	9.61
2126	HAY RIVER	254.84	280.32	9.61
2278	HAY RIVER SOUTH	254.84	280.32	9.61
1603	HAYS	199.52	219.47	7.52
2140	HEART RIVER	254.84	280.32	9.61
1439	HEISLER	114.95	126.45	4.33
1523	HELINA	254.84	280.32	9.61
2174	HENDERSON CK SE	254.84	280.32	9.61
2164	HENDERSON CREEK	254.84	280.32	9.61
1673	HERMIT LAKE	228.09	250.90	8.60
3611	HERMIT LAKE SLS	228.19	251.01	8.60
1866	HIGHLAND RANCH	128.53	141.38	4.85
1402	HILDA WEST	81.64	89.80	3.08
2059	HINES CREEK	254.84	280.32	9.61
2219	HINES CREEK W.	254.84	280.32	9.61
1161	HOLDEN	183.15	201.47	6.91
1528	HOOLE	254.84	280.32	9.61
2047	HOTCHKISS	254.84	280.32	9.61

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)
2065	HOTCHKISS EAST	254.84	280.32	9.61
2094	HOTCHKISS NE B	254.84	280.32	9.61
2095	HOTCHKISS NE C	254.84	280.32	9.61
2054	HOTCHKISS NORTH	254.84	280.32	9.61
2169	HOWARD CREEK E.	254.84	280.32	9.61
1207	HUDSON	169.18	186.10	6.38
1413	HUDSON WEST	140.21	154.23	5.29
1854	HUGHENDEN EAST	208.93	229.82	7.88
1859	HUMMOCK LAKE	107.64	118.40	4.06
2277	HUNT CREEK	254.84	280.32	9.61
2751	HUNT CREEK #2	254.84	280.32	9.61
1436	HUSSAR NORTH	81.64	89.80	3.08
1016	HUSSAR-CHANCELL	84.66	93.13	3.19
1142	HUXLEY	119.28	131.21	4.50
1591	HUXLEY EAST	237.56	261.32	8.96
1241	HYLO	254.84	280.32	9.61
1357	HYLO SOUTH	254.84	280.32	9.61
1479	HYTHE	233.41	256.75	8.80
1277	IDDESLEIGH S.	90.36	99.40	3.41
1678	INDIAN LAKE	141.62	155.78	5.34
1717	INDIAN LAKE #2	141.03	155.13	5.32
3857	INLAND SALES EXCHANGE	156.17	171.79	5.89
1685	IPIATIK LAKE	254.84	280.32	9.61
1441	IRISH	254.84	280.32	9.61
1569	IROQUOIS CREEK	184.76	203.24	6.97
1201	IRVINE	161.17	177.29	6.08
1407	ISLAND LAKE	230.74	253.81	8.70
1694	JACKFISH CREEK	254.84	280.32	9.61
2723	JACKPOT CREEK	254.84	280.32	9.61
2146	JACKSON CREEK	94.20	103.62	3.55
3860	JANUARY CREEK INTERCONNEC	139.95	153.95	5.28
1163	JARROW	254.84	280.32	9.61
1159	JARROW SOUTH	244.94	269.43	9.24
1281	JARROW WEST	254.84	280.32	9.61
1799	JARVIE NORTH	254.84	280.32	9.61
1886	JARVIS BAY	124.60	137.06	4.70
1143	JENNER EAST	81.64	89.80	3.08
1099	JENNER WEST	81.64	89.80	3.08
1385	JENNER WEST B	81.64	89.80	3.08
1167	JOFFRE	179.24	197.16	6.76
1878	JOFFRE EAST	144.24	158.66	5.44
3864	JOFFRE INTERCONNECTION	113.78	125.16	4.29
2267	JONES LAKE	216.37	238.01	8.16
2279	JONES LAKE #2	216.56	238.22	8.17
2241	JONES LAKE N.	251.18	276.30	9.47
2087	JOSEPHINE	254.84	280.32	9.61
2022	JUDY CREEK	254.84	280.32	9.61
2036	JUMPING POUND W	81.64	89.80	3.08
1811	KAKWA	216.47	238.12	8.16
1462	KARR	168.43	185.27	6.35
2013	KAYBOB	190.60	209.66	7.19
2027	KAYBOB 11-36	188.16	206.98	7.09
2020	KAYBOB SOUTH	172.45	189.70	6.50
2035	KAYBOB SOUTH #3	145.73	160.30	5.49
2053	KEG RIVER	254.84	280.32	9.61
2068	KEG RIVER EAST	254.84	280.32	9.61
2216	KEG RIVER NORTH	254.84	280.32	9.61

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 ($\$/10^3m^3$)
1224	KEHO LAKE	88.68	97.55	3.34
1775	KEHO LAKE NORTH	116.33	127.96	4.39
1882	KEIVERS LAKE	81.64	89.80	3.08
2748	KEMP RIVER	254.84	280.32	9.61
1483	KENT	254.84	280.32	9.61
2739	KEPPLER CREEK	254.84	280.32	9.61
1845	KERSEY	81.64	89.80	3.08
1879	KERSEY #2	81.64	89.80	3.08
1627	KETTLE RIVER	254.84	280.32	9.61
2288	KIDNEY LAKE	254.84	280.32	9.61
1608	KIKINO	236.42	260.06	8.91
1162	KILLAM	254.84	280.32	9.61
1298	KILLAM NORTH	254.84	280.32	9.61
1682	KINOSIS	254.84	280.32	9.61
1446	KIRBY	254.84	280.32	9.61
1727	KIRBY NORTH #2	254.84	280.32	9.61
2777	KOTCHO RIVER	254.84	280.32	9.61
2759	KSITUAN R E #2	254.84	280.32	9.61
2134	KSITUAN RIVER	254.84	280.32	9.61
1721	LAC LA BICHE	254.84	280.32	9.61
1860	LACOMBE LAKE	103.59	113.95	3.91
1718	LACOREY	254.84	280.32	9.61
2287	LAFOND CREEK	254.84	280.32	9.61
1210	LAKE NEWELL E.	139.21	153.13	5.25
1562	LAKEVIEW LAKE	101.51	111.66	3.83
1828	LAKEVIEW LAKE #2	101.22	111.34	3.82
2737	LALBY CREEK	254.84	280.32	9.61
1767	LAMERTON	177.83	195.61	6.71
1884	LAMERTON SOUTH	122.44	134.68	4.62
1887	LAMERTON#2	177.83	195.61	6.71
1206	LANFINE	110.52	121.57	4.17
1564	LARKSPUR	254.84	280.32	9.61
2223	LAST LAKE	220.65	242.72	8.32
2151	LASTHILL CREEK	97.33	107.06	3.67
2259	LATHROP CREEK	251.13	276.24	9.47
1874	LAVESTA	113.34	124.67	4.27
1132	LAVOY	196.53	216.18	7.41
1695	LAWRENCE LAKE N	254.84	280.32	9.61
2040	LEAFLAND	173.87	191.26	6.56
1833	LEE LAKE	193.51	212.86	7.30
2179	LEEDALE	102.82	113.10	3.88
2249	LENNARD CREEK	254.84	280.32	9.61
1272	LEO	90.37	99.41	3.41
5003	LIEGE	254.84	280.32	9.61
1536	LINARIA	254.84	280.32	9.61
1857	LINDEN	81.64	89.80	3.08
1872	LITTLE BOW	81.64	89.80	3.08
1494	LITTLE SUNDANCE	134.67	148.14	5.08
2111	LOBSTICK	123.41	135.75	4.65
1465	LONE BUTTE	179.35	197.29	6.76
1069	LONE PINE CREEK	93.65	103.02	3.53
1139	LONE PINE SOUTH	87.43	96.17	3.30
1768	LONESOME LAKE	127.54	140.29	4.81
1630	LONG LAKE WEST	254.84	280.32	9.61
1366	LOUISIANA LAKE	130.28	143.31	4.91
1496	LOUSANA	217.06	238.77	8.18
2128	LOVET CREEK	254.84	280.32	9.61

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 ($/$10^3m^3$)
1386	LUCKY LAKE	254.84	280.32	9.61
3058	LUNDBRECK-COWLEY	81.64	89.80	3.08
2774	MACINTOSH LAKE	234.39	257.83	8.84
5021	MACKAY RIVER	254.84	280.32	9.61
2780	MADDENVILLE	204.06	224.47	7.69
2702	MAHASKA	205.36	225.90	7.74
1229	MAJESTIC	118.38	130.22	4.46
1419	MAKEPEACE NORTH	97.73	107.50	3.68
1873	MALMO	182.54	200.79	6.88
1719	MANATOKEN LAKE	254.84	280.32	9.61
2720	MANIR	243.35	267.69	9.18
1273	MAPLE GLEN	95.87	105.46	3.61
1572	MARLBORO	186.83	205.51	7.04
1663	MARLBORO EAST	187.04	205.74	7.05
2713	MARLOW CREEK	254.84	280.32	9.61
2762	MARSH HD CK W#2	148.70	163.57	5.61
2750	MARSH HEAD CK WEST	148.58	163.44	5.60
2228	MARSH HEAD CRK	167.53	184.28	6.32
1091	MARTEN HILLS	254.84	280.32	9.61
1672	MARTEN HILLS N.	254.84	280.32	9.61
1097	MARTEN HILLS S.	254.84	280.32	9.61
1270	MATZHIWIN EAST	124.13	136.54	4.68
1284	MATZHIWIN N.E.	92.91	102.20	3.50
1379	MATZHIWIN SOUTH	81.64	89.80	3.08
1150	MATZHIWIN WEST	86.27	94.90	3.25
1514	MAUGHAN	254.84	280.32	9.61
1633	MAY HILL	254.84	280.32	9.61
2790	MAYBERNE	137.42	151.16	5.18
2706	MCLEAN CREEK	254.84	280.32	9.61
2144	MCLENNAN	254.84	280.32	9.61
2710	MCMILLAN LAKE	254.84	280.32	9.61
6404	MCNEILL BORDER	81.64	89.80	3.08
1704	MEADOW CREEK	254.84	280.32	9.61
1707	MEADOW CREEK E.	254.84	280.32	9.61
1705	MEADOW CRK WEST	254.84	280.32	9.61
1338	MEANOOK	254.84	280.32	9.61
1017	MED HAT N. #1	81.64	89.80	3.08
1184	MED HAT N. ARCO	81.64	89.80	3.08
1325	MED HAT N. F	81.64	89.80	3.08
1205	MED HAT N.W.	81.64	89.80	3.08
1018	MED HAT S. #1	82.00	90.20	3.09
1043	MED HAT S. #2	81.64	89.80	3.08
1128	MED HAT S. #4	81.64	89.80	3.08
1172	MED HAT WEST	81.64	89.80	3.08
1186	MEDICINE HAT E.	98.00	107.80	3.70
1214	MEDICINE RVR A	247.08	271.79	9.32
2778	MEGA RIVER	254.84	280.32	9.61
2781	MEGA RIVER #2	254.84	280.32	9.61
1645	METISKOW NORTH	193.45	212.80	7.29
1362	MEYER	254.84	280.32	9.61
1508	MICHICHI	174.99	192.49	6.60
1146	MIKWAN	163.09	179.40	6.15
1427	MIKWAN EAST	254.84	280.32	9.61
1144	MIKWAN NORTH	119.94	131.93	4.52
2237	MILLERS LAKE	143.16	157.48	5.40
1524	MILLS	254.84	280.32	9.61
1578	MILO	88.89	97.78	3.35

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 ($\$/10^3m^3$)
1396	MINBURN	254.84	280.32	9.61
2149	MINNEHIK-BK L B	121.56	133.72	4.58
2010	MINNEHIK-BK LK	120.88	132.97	4.56
1693	MINNOW LAKE	184.02	202.42	6.94
1658	MIQUELON LAKE	254.84	280.32	9.61
2273	MIRAGE	254.84	280.32	9.61
1500	MIRROR	189.60	208.56	7.15
1090	MITSUE	254.84	280.32	9.61
3889	MITSUE SALES INTERCONNECTI	254.84	280.32	9.61
1457	MITSUE SOUTH	254.84	280.32	9.61
3863	MONARCH EXCHANGE	88.77	97.65	3.35
1605	MONITOR CREEK	125.94	138.53	4.75
1771	MONITOR CREEK W	193.20	212.52	7.28
1222	MONITOR SOUTH	132.30	145.53	4.99
1292	MONS LAKE	254.84	280.32	9.61
1355	MONS LAKE EAST	254.84	280.32	9.61
1823	MOOSE PORTAGE	212.02	233.22	7.99
1484	MOOSELAKE RIVER	254.84	280.32	9.61
1460	MORECAMBE	254.84	280.32	9.61
1458	MORRIN	173.68	191.05	6.55
1781	MOSS LAKE	254.84	280.32	9.61
1802	MOSS LAKE NORTH	237.69	261.46	8.96
1641	MOUNT VALLEY	225.15	247.67	8.49
2732	MOUNTAIN LAKE	241.00	265.10	9.09
2206	MULLIGAN CRK S.	254.84	280.32	9.61
1774	MUNSON	234.67	258.14	8.85
1888	MUNSON #2	234.67	258.14	8.85
1551	MURRAY LAKE	202.34	222.57	7.63
2236	MUSKEG CREEK	254.84	280.32	9.61
1785	MUSKWA RIVER	254.84	280.32	9.61
2711	MUSREAU LAKE	249.54	274.49	9.41
1730	MYRNAM	254.84	280.32	9.61
2745	NARRAWAY RIVER	253.66	279.03	9.56
3009	NEPTUNE	241.25	265.38	9.10
1276	NESTOW	244.45	268.90	9.22
1316	NETOOK	254.84	280.32	9.61
1020	NEVIS NORTH	137.32	151.05	5.18
1019	NEVIS SOUTH	133.12	146.43	5.02
1502	NEWBROOK	254.84	280.32	9.61
1140	NEWELL NORTH	81.64	89.80	3.08
1747	NIGHTINGALE	81.64	89.80	3.08
2242	NIOBE CREEK	234.21	257.63	8.83
1194	NIPISI	254.84	280.32	9.61
2071	NITON	137.53	151.28	5.19
2172	NITON NORTH	150.58	165.64	5.68
3368	NOEL LAKE SALES	230.46	253.51	8.69
6006	NORTH DUNCAN	254.84	280.32	9.61
6009	NORTH HANGINGSTONE	254.84	280.32	9.61
3454	NORTH PENHOLD SALES	98.28	108.11	3.71
6008	NORTH THORNBURY (RIO)	254.84	280.32	9.61
2767	NOSE MOUNTAIN	244.06	268.47	9.20
1865	NOSEHILL CK NORTH	141.40	155.54	5.33
2192	NOTIKEWIN RIVER	254.84	280.32	9.61
2218	NOTIKEWIN RVR N	254.84	280.32	9.61
1829	OBED NORTH	138.24	152.06	5.21
1532	OHATON	254.84	280.32	9.61
2796	OLDMAN	139.00	152.90	5.24

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)
1053	OLDS	111.53	122.68	4.21
1545	OPAL	254.84	280.32	9.61
1814	ORLOFF LAKE	254.84	280.32	9.61
1716	OSBORNE LAKE	254.84	280.32	9.61
1812	OSLAND LAKE	254.84	280.32	9.61
1587	OVERLEA	254.84	280.32	9.61
1817	OWL LAKE	254.84	280.32	9.61
2728	OWL LAKE SOUTH	254.84	280.32	9.61
2742	OWL LAKE STH #2	254.84	280.32	9.61
2746	OWL LAKE STH #3	254.84	280.32	9.61
1007	OYEN	118.28	130.11	4.46
1058	OYEN NORTH	89.17	98.09	3.36
1126	OYEN SOUTHEAST	81.64	89.80	3.08
2098	PADDLE PRAIR S.	254.84	280.32	9.61
2093	PADDLE PRAIRIE	254.84	280.32	9.61
1307	PADDLE RIVER	236.50	260.15	8.92
1852	PAKAN LAKE	185.68	204.25	7.00
1728	PARADISE VALLEY	254.84	280.32	9.61
1853	PARKER CREEK	254.84	280.32	9.61
1665	PARSONS LAKE	254.84	280.32	9.61
2089	PASS CREEK	159.81	175.79	6.03
2168	PASS CREEK WEST	153.45	168.80	5.79
2260	PASTECHO RIVER	254.84	280.32	9.61
1278	PATRICIA	81.64	89.80	3.08
1289	PATRICIA WEST	96.52	106.17	3.64
2793	PEAVINE CREEK	254.84	280.32	9.61
3804	PEMBINA INTERCONNECTION	105.76	116.34	3.99
1180	PENHOLD	94.72	104.19	3.57
1607	PENHOLD WEST	132.39	145.63	4.99
2280	PETE LAKE	254.84	280.32	9.61
2247	PETE LAKE SOUTH	212.27	233.50	8.00
1714	PICHE LAKE	254.84	280.32	9.61
1610	PICTURE BUTTE	188.88	207.77	7.12
2046	PIONEER	127.63	140.39	4.81
1739	PIPER CREEK	130.16	143.18	4.91
1797	PITLO	254.84	280.32	9.61
1110	PLAIN LAKE	247.72	272.49	9.34
1858	POE	127.63	140.39	4.81
2173	POISON CREEK	175.90	193.49	6.63
1881	PORTERS BUTTE	81.64	89.80	3.08
3879	PRIDDIS INTERCONNECTION	81.64	89.80	3.08
1246	PRINCESS EAST	81.64	89.80	3.08
1183	PRINCESS WEST	81.64	89.80	3.08
1010	PRINCESS-DENHAR	81.64	89.80	3.08
1022	PRINCESS-IDDESL	81.64	89.80	3.08
2153	PROGRESS	220.94	243.03	8.33
2191	PROGRESS EAST	227.59	250.35	8.58
1304	PROSPERITY	243.33	267.66	9.17
1211	PROVOST MONITOR	241.94	266.13	9.12
1003	PROVOST NORTH	144.11	158.52	5.43
1013	PROVOST SOUTH	156.06	171.67	5.88
1045	PROVOST WEST	214.23	235.65	8.08
1038	PROVOST-KESSLER	233.86	257.25	8.82
1601	QUEENSTOWN	191.89	211.08	7.24
2026	QUIRK CREEK	81.64	89.80	3.08
1741	RABBIT LAKE	254.84	280.32	9.61
2201	RAINBOW LAKE S.	254.84	280.32	9.61

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)
1106	RAINIER	81.64	89.80	3.08
1380	RAINIER S.W.	95.68	105.25	3.61
1378	RAINIER SOUTH	126.32	138.95	4.76
1282	RALSTON	81.64	89.80	3.08
1826	RALSTON SOUTH	86.86	95.55	3.28
2148	RAMBLING CREEK	254.84	280.32	9.61
2213	RAMBLING CRK E.	254.84	280.32	9.61
1164	RANFURLY	249.92	274.91	9.42
3911	RANFURLY INTERCONNECT	249.96	274.96	9.42
1189	RANFURLY NORTH	177.44	195.18	6.69
1165	RANFURLY WEST	211.65	232.82	7.98
2104	RAT CREEK	110.57	121.63	4.17
2265	RAT CREEK SOUTH	123.55	135.91	4.66
2252	RAT CREEK WEST	132.95	146.25	5.01
2193	RAY LAKE SOUTH	254.84	280.32	9.61
2166	RAY LAKE WEST	254.84	280.32	9.61
1209	REDCLIFF	137.59	151.35	5.19
1219	REDCLIFF SOUTH	118.11	129.92	4.45
1838	REDCLIFF STH #2	118.11	129.92	4.45
1346	REDCLIFF WEST	129.11	142.02	4.87
3438	REDWATER B SL	254.84	280.32	9.61
3406	REDWATER SALES	254.84	280.32	9.61
2779	RESTHAVEN	193.91	213.30	7.31
2785	RESTHAVEN NORTH	188.30	207.13	7.10
1057	RETLAW	89.67	98.64	3.38
1218	RETLAW SOUTH	113.38	124.72	4.27
1392	RIBSTONE	254.84	280.32	9.61
1374	RICH LAKE	254.84	280.32	9.61
1135	RICINUS	109.02	119.92	4.11
1372	RICINUS SOUTH	107.02	117.72	4.04
1437	RICINUS WEST	113.15	124.47	4.27
2782	RIDGEVALLEY	194.01	213.41	7.32
1949	RIMBEY-WESTEROSE SUMMARY	120.31	132.34	4.54
3405	RIM-WEST SALES	120.31	132.34	4.54
1510	RIVERCOURSE	254.84	280.32	9.61
1499	ROBB	154.08	169.49	5.81
1336	ROCHESTER	254.84	280.32	9.61
1400	ROCK ISLAND LK	254.84	280.32	9.61
1820	ROCK ISLAND S2	254.84	280.32	9.61
1134	ROCKYFORD	81.64	89.80	3.08
1579	ROSE LYNNE	81.64	89.80	3.08
1885	ROSEGLEN	90.18	99.20	3.40
1466	ROSEMARY	81.64	89.80	3.08
1461	ROSEMARY NORTH	81.64	89.80	3.08
2099	ROSEVEAR SOUTH	144.46	158.91	5.45
2725	ROSSBEAR LAKE	254.84	280.32	9.61
1706	ROURKE CRK EAST	254.84	280.32	9.61
1540	ROWLEY	165.16	181.68	6.23
1299	ROYAL PARK	161.38	177.52	6.08
1530	RUMSEY	170.97	188.07	6.45
1867	RUMSEY NORTH #2	233.46	256.81	8.80
3912	RUNNING LAKE INTERCONNECT	254.84	280.32	9.61
2261	RUSSELL CREEK	254.84	280.32	9.61
1311	SADDLE LAKE N.	215.17	236.69	8.11
1310	SADDLE LAKE W.	254.84	280.32	9.61
2281	SAND CREEK	122.74	135.01	4.63
2758	SAWN LAKE	254.84	280.32	9.61

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)
2792	SAWN LAKE EAST	254.84	280.32	9.61
3481	SAWRIDGE SALES	254.84	280.32	9.61
1537	SCOTFIELD	194.44	213.88	7.33
1827	SEDALIA	104.36	114.80	3.93
1036	SEDALIA NORTH	197.65	217.42	7.45
1023	SEDALIA SOUTH	115.74	127.31	4.36
1114	SEDGEWICK	254.84	280.32	9.61
1395	SEDGEWICK EAST	254.84	280.32	9.61
1403	SEDGEWICK NORTH	254.18	279.60	9.58
1447	SEIU CREEK	81.64	89.80	3.08
1370	SEPTEMBER LK N.	254.84	280.32	9.61
1847	SERVICEBERRY CREEK	81.64	89.80	3.08
3862	SEVERN CREEK INTERCONNEC	81.64	89.80	3.08
3940	SHADY OAK INTERCONNECTION	156.63	172.29	5.91
1871	SHARPLES	86.32	94.95	3.25
1846	SHARROW SOUTH#2	81.64	89.80	3.08
3439	SHEERNESS SALES	81.64	89.80	3.08
2783	SHEKILIE RVR EAST	254.84	280.32	9.61
2276	SHEKILIE RVR N.	254.84	280.32	9.61
2798	SHERRI VAIL	148.03	162.83	5.58
1008	SIBBALD	151.05	166.16	5.70
2170	SILVERWOOD	254.84	280.32	9.61
1806	SIMON LAKES	254.84	280.32	9.61
2028	SIMONETTE	218.02	239.82	8.22
1354	SLAWA NORTH	254.84	280.32	9.61
2235	SLIMS LAKE	254.84	280.32	9.61
2137	SLOAT CREEK	254.84	280.32	9.61
1521	SMITH	254.84	280.32	9.61
1637	SMITH WEST	254.84	280.32	9.61
2165	SNEDDON CREEK	254.84	280.32	9.61
2253	SNIPE LAKE	254.84	280.32	9.61
2264	SNOWFALL CREEK	254.84	280.32	9.61
2763	SNUFF MOUNTAIN	164.01	180.41	6.18
1556	SOUTH SASK RVR	227.40	250.14	8.57
1580	SPEAR LAKE	254.84	280.32	9.61
1856	SPOTTED CREEK	150.29	165.32	5.67
1341	SPRUCEFIELD	254.84	280.32	9.61
1487	SPURFIELD	254.84	280.32	9.61
1581	SQUARE LAKE	254.84	280.32	9.61
2775	SQUIRREL MOUNTAIN	250.13	275.14	9.43
1519	ST. BRIDES	254.84	280.32	9.61
1414	ST. LINA	254.84	280.32	9.61
1415	ST. LINA NORTH	254.84	280.32	9.61
1416	ST. LINA WEST	254.84	280.32	9.61
1534	STANDARD	84.02	92.42	3.17
1131	STANMORE	115.84	127.42	4.37
1156	STANMORE SOUTH	107.85	118.64	4.07
1371	STEELE LAKE	254.84	280.32	9.61
2284	STEEN RIVER	254.84	280.32	9.61
1308	STETTLER SOUTH	202.55	222.81	7.64
1388	STEVEVILLE	81.64	89.80	3.08
1565	STONEY CREEK	254.84	280.32	9.61
1566	STONEY CREEK W.	230.33	253.36	8.68
1115	STRACHAN	100.08	110.09	3.77
1179	STROME-HOLMBERG	158.84	174.72	5.99
2030	STURGEON LAKE S	239.80	263.78	9.04
1423	SUFFIELD WEST	103.99	114.39	3.92

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)
1193	SULLIVAN LAKE	171.63	188.79	6.47
1516	SUNDANCE CREEK	194.53	213.98	7.33
1595	SUNDANCE CRK E.	135.73	149.30	5.12
1696	SUNDAY CREEK S.	254.84	280.32	9.61
1079	SUNNYNOOK	81.64	89.80	3.08
2795	SUNVALLEY	154.66	170.13	5.83
1054	SYLVAN LAKE	115.73	127.30	4.36
1187	SYLVAN LAKE EAST #1	111.80	122.98	4.22
1855	SYLVAN LAKE EAST #2	110.49	121.54	4.17
1191	SYLVAN LK SOUTH	129.97	142.97	4.90
1055	SYLVAN LK WEST	128.02	140.82	4.83
2082	TANGENT	254.84	280.32	9.61
2121	TANGENT B	254.84	280.32	9.61
2208	TANGENT EAST	254.84	280.32	9.61
2157	TANGHE CREEK	254.84	280.32	9.61
2204	TANGHE CREEK #2	254.84	280.32	9.61
1440	TAPLOW	81.64	89.80	3.08
1837	TAWADINA CREEK	100.44	110.48	3.79
2076	TEEPEE CREEK	254.84	280.32	9.61
5027	THICKWOOD HILLS	254.84	280.32	9.61
1377	THORHILD	254.84	280.32	9.61
1430	THORHILD WEST	229.52	252.47	8.65
6005	THORNBURY EAST	254.84	280.32	9.61
6002	THORNBURY MARIANA	254.84	280.32	9.61
6001	THORNBURY NORTH (AG THORN	254.84	280.32	9.61
6000	THORNBURY WEST	254.84	280.32	9.61
1029	THREE HILLS CRK	125.20	137.72	4.72
1335	THREE HLS CRK W	88.22	97.04	3.33
1348	TIDE LAKE	81.64	89.80	3.08
1639	TIDE LAKE B	81.64	89.80	3.08
1331	TIDE LAKE EAST	81.64	89.80	3.08
1268	TIDE LAKE NORTH	81.64	89.80	3.08
1223	TIDE LAKE SOUTH	81.64	89.80	3.08
1412	TIELAND	254.84	280.32	9.61
1314	TILLEBROOK	81.64	89.80	3.08
1644	TILLEBROOK WEST	81.64	89.80	3.08
1169	TILLEY	81.64	89.80	3.08
1839	TILLEY SOUTH #2	197.72	217.49	7.46
2769	TIMBERWOLF	254.84	280.32	9.61
2116	TONY CREEK N.	198.66	218.53	7.49
2754	TOPLAND	254.84	280.32	9.61
1841	TORLEA EAST	192.83	212.11	7.27
1869	TORRINGTON E #2	81.64	89.80	3.08
1621	TORRINGTON EAST	81.82	90.00	3.09
1442	TRAVERS	81.64	89.80	3.08
1574	TROCHU	151.41	166.55	5.71
1848	TUDOR	81.64	89.80	3.08
1343	TWEEDIE	254.84	280.32	9.61
1256	TWEEDIE SOUTH	254.84	280.32	9.61
1699	TWELVE MILE COULEE	128.65	141.52	4.85
1190	TWINING	101.02	111.12	3.81
1066	TWINING NORTH	107.97	118.77	4.07
3113	TWINLAKES CK SL	254.84	280.32	9.61
2224	TWO CREEKS	254.84	280.32	9.61
2229	TWO CREEKS EAST	254.84	280.32	9.61
1120	UKALTA	241.06	265.17	9.09
1317	UKALTA EAST	207.80	228.58	7.84

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 ($\$/10^3m^3$)
1250	UNITY BORDER	182.72	200.99	6.89
1154	VALE	102.74	113.01	3.87
1212	VALE EAST	135.13	148.64	5.10
2107	VALHALLA	220.54	242.59	8.32
2227	VALHALLA #2	220.50	242.55	8.31
2189	VALHALLA EAST	234.84	258.32	8.85
1801	VANDERSTEENE LK	254.84	280.32	9.61
2788	VEDA	246.08	270.69	9.28
1056	VERGER	83.57	91.93	3.15
1077	VERGER-HOMESTEA	81.64	89.80	3.08
1203	VERGER-MILLICEN	81.64	89.80	3.08
3916	VETERAN SUMMARY	242.97	267.27	9.16
1606	VICTOR	230.77	253.85	8.70
1347	VIKING EAST	160.33	176.36	6.05
3890	VIKING INTERCONNECTION	151.66	166.83	5.72
1257	VIKING NORTH	218.57	240.43	8.24
1464	VILNA	254.84	280.32	9.61
1527	VIMY	254.84	280.32	9.61
2034	VIRGINIA HILLS	254.84	280.32	9.61
1076	VULCAN	111.64	122.80	4.21
1724	WABASCA	254.84	280.32	9.61
1669	WADDELL CREEK	254.84	280.32	9.61
1736	WADDELL CREEK W	254.84	280.32	9.61
1383	WAINWRIGHT EAST	254.84	280.32	9.61
1199	WAINWRIGHT S.	251.40	276.54	9.48
6015	WANDER TOWER (TALISMAN)	254.84	280.32	9.61
1822	WANDERING RIVER	254.84	280.32	9.61
1340	WARDLOW EAST	81.64	89.80	3.08
2133	WARRENSVILLE	254.84	280.32	9.61
1353	WARSPITE	202.96	223.26	7.65
1118	WARWICK	157.63	173.39	5.94
1173	WARWICK SOUTH	175.38	192.92	6.61
2029	WASKAHIGAN	159.78	175.76	6.02
2160	WATER VALLEY	81.64	89.80	3.08
2123	WATINO	254.84	280.32	9.61
1945	WATR1/WATR2 SUM	81.64	89.80	3.08
1570	WATTS	127.54	140.29	4.81
1021	WAYNE NORTH	127.77	140.55	4.82
1039	WAYNE-DALUM	118.16	129.98	4.46
1107	WAYNE-ROSEBUD	81.64	89.80	3.08
1585	WEASEL CREEK	244.17	268.59	9.21
1723	WEAVER LAKE	254.84	280.32	9.61
1780	WEAVER LAKE S.	254.84	280.32	9.61
2207	WEBSTER	254.84	280.32	9.61
2248	WEBSTER NORTH	254.84	280.32	9.61
1825	WELLING	245.69	270.26	9.26
2158	WEMBLEY	205.70	226.27	7.76
2120	WEST PEMBINA S.	120.08	132.09	4.53
1188	WEST VIKING	188.94	207.83	7.12
1321	WESTLOCK	254.84	280.32	9.61
3871	WESTLOCK SALES INTERCONNE	254.84	280.32	9.61
1787	WHISTWOW	254.84	280.32	9.61
2701	WHITBURN EAST	241.09	265.20	9.09
1094	WHITECOURT	211.30	232.43	7.97
2075	WHITELAW	245.50	270.05	9.26
2055	WHITEMUD EAST	254.84	280.32	9.61
3917	WHITEMUD WEST-WHITEMUD RI	254.84	280.32	9.61

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 ($\$/10^3m^3$)
1345	WHITFORD	198.48	218.33	7.48
1684	WIAU LAKE	254.84	280.32	9.61
2005	WILDCAT HILLS	81.64	89.80	3.08
1661	WILDHAY RIVER	143.96	158.36	5.43
1650	WILDUNN CREEK E	88.05	96.86	3.32
2112	WILLESDEN GR N.	93.13	102.44	3.51
2014	WILLESDEN GREEN	90.87	99.96	3.43
1428	WILLINGDON	176.83	194.51	6.67
1652	WILLOW RIVER	254.84	280.32	9.61
1759	WILLOW RIVER N	254.84	280.32	9.61
2019	WILSON CREEK	153.40	168.74	5.78
2171	WILSON CREEK SE	154.51	169.96	5.83
1046	WIMBORNE	93.33	102.66	3.52
1234	WIMBORNE NORTH	100.39	110.43	3.79
2707	WINAGAMI LAKE	254.84	280.32	9.61
2012	WINDFALL	154.11	169.52	5.81
1628	WINEFRED RVR N.	254.84	280.32	9.61
1671	WINEFRED RVR S.	254.84	280.32	9.61
1070	WINTERING HILLS	82.89	91.18	3.13
1104	WINTERING HLS E	81.64	89.80	3.08
2147	WITHROW	116.55	128.21	4.39
2124	WOKING	254.84	280.32	9.61
2214	WOLVERINE RIVER	254.84	280.32	9.61
1035	WOOD RIVER	170.65	187.72	6.43
3425	WOOD RVR SALES	170.43	187.47	6.43
2765	WOOSTER	154.50	169.95	5.83
1342	YOUNGSTOWN	185.31	203.84	6.99
2060	ZAMA LAKE	254.84	280.32	9.61
1944	ZAMA LAKE SUMMARY	254.84	280.32	9.61

Distance Band	Maximum Distance Between Receipt Point and Delivery Point (km)		FT-P Demand Rate per Month
	From	To	($/10^{3}m^3)
1	0	25	96.17
2	>25	50	104.04
3	>50	75	111.92
4	>75	100	119.79
5	>100	125	127.66
6	>125	150	135.54
7	>150	175	143.41
8	>175	200	151.28
9	>200	225	159.16
10	>225	250	167.03
11	>250	275	174.90
12	>275	300	182.77
13	>300	325	190.65
14	>325	350	198.52
15	>350	375	206.39
16	>375	400	214.27
17	>400	425	222.14
18	>425	450	230.01
19	>450	475	237.89
20	>475	500	245.76
21	>500	525	253.63
22	>525	550	261.51
23	>550	575	269.38