TransCanada
In business to deliver

450 - 1st Street S.W.
Calgary, Alberta T2P 5H1
Direct Phone: (403) 920-7184
Fax: (403) 920-2347
Email: celine_belanger@transcanada.com

April 15, 2005

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

By Electronic Filing

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

Dear Sir:

Re: NOVA Gas Transmission Ltd. (NGTL)
2005 General Rate Application (GRA) Phase 2

Enclosed for filing with the Board is NGTL's 2005 General Rate Application Phase 2.

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

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

Yours truly,

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

Céline Bélanger
Vice President, Regulatory Services

Enclosures

cc: Tolls, Tariff, Facilities and Procedures Committee
Alberta System Shippers

NOVA Gas Transmission Ltd.

2005 General Rate Application Phase 2
Table of Contents

ALBERTA ENERGY AND UTILITIES BOARD

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

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

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

IN THE MATTER OF an Application by NOVA Gas Transmission Ltd. (NGTL) to the Alberta Energy and Utilities Board (Board) for an order fixing final rates, tolls and charges for Alberta System services provided by NGTL from January 1, 2005 to December 31, 2005.

2005 GENERAL RATE APPLICATION PHASE 2

NGTL applies to the Board under Part 4 of the *Gas Utilities Act* for an order:

(a) fixing final 2005 rates, tolls, and charges for Alberta System services provided by NGTL from January 1, 2005 to December 31, 2005, on the basis proposed in the Application;

(b) approving NGTL's implementation and use of an energy, rather than a volumetric, basis for existing and new export delivery services, as proposed in the Application;

(c) approving minor "housekeeping" amendments to certain Rate Schedules and the General Terms and Conditions of NGTL's Tariff, as proposed in the Application; and

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

In support of its 2005 General Rate Application Phase 2, NGTL provides and relies on the information in the Application, including the attached evidence, appendices, and explanatories, and any additional information that NGTL may file, as directed or permitted by the Board.

Respectfully submitted.

Calgary, Alberta
April 15, 2005

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

Per: Céline Bélanger

Céline Bélanger
Vice President
Regulatory Services

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

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

Attention: Klaus Exner
Director, Applications and
Compliance, Tolls and Tariffs

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

and to:

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

Attention: Patrick M. Keys
Associate General Counsel,
Regulatory

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

1.2 INTRODUCTION AND EXECUTIVE SUMMARY

Q1. What is the purpose of this Application?

A1. This Application is NGTL's 2005 General Rate Application (GRA), Phase 2. NGTL seeks Board approval of final rates, tolls and charges for Alberta System services provided from January 1, 2005 to December 31, 2005 on the basis proposed in the Application.

Q2. Why is NGTL filing the Application at this time?

A2. NGTL is filing this Application for two primary reasons.

First, NGTL requires approval of final rates, tolls and charges for Alberta System services, commencing January 1, 2005. The Board previously approved final rates, tolls and charges for service in Decision 2004-108 only to December 31, 2004.[1]

Second, NGTL files this Application in compliance with the Board's direction in Decision 2004-097 that NGTL "submit a Phase II application for 2005."[2] The Board also directed NGTL in Decision 2004-097 to include in the application an updated distance of haul study, an updated cost of haul study, and a fully allocated cost of service study, and to "address a reasonable allocation of transmission costs greater than zero to the FT-A rate... for consideration by the Board."[3]

The Board originally directed NGTL in Decision 2004-097 to file the Application by April 1, 2005. However, on March 30, 2005, the Board extended the filing date to April 15, 2005 at NGTL's request.

Q3. What is the basis for the proposed final 2005 rates, tolls and charges?

A3. The proposed final 2005 rates, tolls and charges are based on the 2005 revenue requirement which NGTL requested approval of in its 2005-2007 Revenue Requirement

[1] Alberta Energy and Utilities Board Decision 2004-108, NOVA Gas Transmission Ltd., 2004 General Rate Application, Phase 2 Compliance Filing, (December 14, 2004).
[2] Alberta Energy and Utilities Board Decision 2004-097, NOVA Gas Transmission Ltd., 2004 General Rate Application, Phase 2, (October 26, 2004) (EUB Decision 2004-097), page 19.
[3] EUB Decision 2004-097, page 19.

Settlement Application (Settlement Application)[4] and the rate design methodology and services discussed in this Application.

Q4. What rates, tolls, and charges is NGTL using for services pending determination of its 2005 revenue requirement and final 2005 rates, tolls and charges?

A4. NGTL is using 2005 interim rates, tolls and charges approved by the Board in Order U2004-446, issued on December 14, 2004. NGTL expects these interim rates, tolls and charges will remain in place until the Board has determined the Settlement Application, this Application, and any consequential compliance filings.

Q5. Has NGTL responded to the Board's directions in Decision 2004-097 to provide an updated distance of haul study, an updated cost of haul study, and a detailed, fully allocated cost of service study in its 2005 GRA Phase 2?

A5. Yes. NGTL provides the required information, with supporting analysis and discussion, in Section 2 of this Application.

The information in Section 2 also includes detailed analysis of alternatives to NGTL's existing cost allocation methodology. Certain of these alternatives specifically respond to the Board's direction in Decision 2004-097 that NGTL address the allocation of transmission costs to intra-Alberta delivery service.

Q6. Is NGTL proposing in this Application any changes to the existing cost allocation methodologies?

A6. No. NGTL submits that its analysis of the alternative cost allocation methodologies demonstrates that none of the alternatives is clearly better than the existing methodology, based on all relevant factors.

Q7. Is NGTL proposing in this Application any changes to the existing rate design?

A7. No. NGTL submits that the existing rate design, approved in Decision 2003-051[5] and affirmed in Decision 2004-097, continues to be appropriate for 2005. The existing rate

[4] EUB Application No. 1393246, (March 18, 2005).
[5] Alberta Energy and Utilities Board Decision 2003-051, NOVA Gas Transmission Ltd., 2003 Revenue Requirement and Tariff Settlement Applications, (June 24, 2003) (EUB Decision 2003-051), page 27.

design reflects reasonable cost allocation methodologies appropriate to the Alberta System, meets generally accepted rate design criteria, and results in rates, tolls and charges that are just and reasonable.

In addition, NGTL understands that the majority of its stakeholders support the use of the existing rate design for 2005. The design resulted from significant collaborative efforts and compromises of competing interests among NGTL's diverse stakeholder group. NGTL believes that changes to any one part of the existing rate design for 2005 would significantly, and unpredictably, disrupt the balance of competing interests which it represents.

Q8. Has NGTL provided in the Application any analysis of cost accountability provisions for intra-Alberta delivery service?

A8. Yes. NGTL presents and discusses in Section 2.4 of the Application potential alternatives to the existing terms for intra-Alberta delivery service. These alternatives could be considered in place of rate design changes to modify cost accountability for intra-Alberta delivery service. The alternatives include the replacement of the existing Firm Transportation-Alberta (FT-A) service commodity rate with a demand rate and the addition of a new Interruptible Transportation-Alberta (IT-A) service. If implemented, these changes would eliminate the existing requirements for a minimum annual volume commitment because FT-A service would become subject to primary term requirements analogous to those in place for firm receipt service.

NGTL also presents four options to the existing extension annual volume (EAV) calculation associated with new extension facilities for intra-Alberta delivery service.

Q9. Is NGTL proposing in this Application to change existing intra-Alberta delivery service accountability provisions for 2005, based on its consideration of these potential alternatives?

A9. No. NGTL believes that the existing accountability provisions, in conjunction with the existing rate design, remain appropriate for 2005.

Q10. Is NGTL proposing in this Application any changes to the terms and conditions of other existing services or other provisions of its Tariff?

A10. Yes. NGTL proposes, for all existing and new contracts for export delivery services, that contract quantities be expressed on an energy (GJ) basis, rather than the existing volumetric (10^3m^3) basis. NGTL describes the need for, and the implications of, the proposed change in Section 3 of the Application. NGTL proposes that these changes become effective November 1, 2006.

NGTL also proposes a number of minor "housekeeping" changes to the Tariff. It presents and describes these amendments in Section 3.0 of the Application.

Q11. Does that conclude NGTL's evidence in this section?

A11. Yes.

2.0 RATE DESIGN

2.1 INTRODUCTION

Q1. What is the purpose of the evidence in this section?

A1. In this section NGTL responds to certain Board directives in Decision 2004-097.[1] Specifically, NGTL provides a Cost of Service (COS) study in which it uses the existing cost allocation methodology, a COS study in which it evaluates several alternative approaches to cost allocation, an updated Distance of Haul (DOH) study, and an updated Cost of Haul (COH) study. NGTL specifically addresses, as part of its evaluation of cost allocation methodologies, an allocation of transmission costs to intra-Alberta delivery service.

In addition, NGTL provides information and analysis of intra-Alberta delivery service accountability measures and presents and discusses the merits of potential alternative measures.

Q2. How is the evidence in this section organized?

A2. NGTL has organized the evidence in this section as follows:

Sub-section 2.2: presentation and discussion of the results of its COS studies, the 2004 DOH study and the 2004 COH study;

Sub-section 2.3: assessment of the existing rate design against generally accepted rate design criteria;

Sub-section 2.4: presentation and discussion of the results of its analysis of existing intra-Alberta delivery service accountability and potential alternative measures; and

Sub-section 2.5: summary of the evidence in Section 2 and the conclusions to be drawn from it.

[1] EUB Decision 2004-097, pages 31 and 32.

Q3. Has NGTL sought external advice to assist it with the preparation of this Application?

A3. Yes. NGTL retained Dr. Stephen Gaske of Zinder Companies Inc. to provide expert advice on cost allocation and rate design matters applicable to the Alberta System.

Specifically NGTL asked Dr. Gaske to:

- describe the concepts and principles that are important for analyzing NGTL's costs of providing services;
- evaluate from an economic and ratemaking perspective the reasonableness of each of the cost allocation and rate design methodologies examined by NGTL;
- review NGTL's existing accountability provisions for intra-Alberta delivery points and render an opinion as to whether these are reasonable and appropriate; and
- review the role of competition in determining a reasonable rate structure for NGTL's Alberta System.

Dr. Gaske has provided written testimony which appears as Appendix 2D.

2.2 COST ALLOCATION

Q4. What is the purpose of the evidence in this sub-section?

A4. The purpose of this evidence is two-fold: to present and discuss the results of the various cost allocation methodologies and to recommend an appropriate approach to be used for the Alberta System for 2005. NGTL has organized the evidence in this sub-section as follows:

Sub-section 2.2.1: examination of appropriate cost allocation methodologies for the Alberta System, including a review of its 2004 DOH and 2004 COH studies; and

Sub-section 2.2.2: discussion, analysis and comparison of the existing cost allocation methodology and six alternatives.

2.2.1 Appropriate Cost Allocation for the Alberta System

Q5. What are the objectives of a COS study?

A5. Under ideal circumstances, a COS study will identify the major cost relationships between the various services provided by a utility. All of the utility's costs are then assigned to the utility's services or otherwise allocated using appropriate allocation methodologies.

The Board has considered the purpose and structure of a cost of service study in various decisions. Recently, it stated in Decision 2004-079:

> The primary tool utilized in determining an appropriate cost allocation is a Cost of Service Study (COSS). A COSS will ordinarily analyze the costs incurred in providing regulated services, categorize or functionalize these costs and then determine an appropriate set of methodologies for the allocation of these costs.[2]

[2] Alberta Energy and Utilities Board Decision 2004-079, ATCO Pipelines General Rate Application Phase II, (September 27, 2004) (EUB Decision 2004-079), page 5.

In relation to the Alberta System specifically, the Board stated in Decision 2003-051:

> The COS analysis will undoubtedly assist NGTL, parties and the Board in the review of cost accountability and cost allocation, and provide information that should assist in review of competitive issues and rate design.[3]

Q6. Can all costs be directly assigned to services on a one-to-one basis?

A6. Ideally there would be a one-to-one relationship between each service and its underlying cost structure. However, the ability to segregate costs on a one-to-one basis is dependent on the nature of the pipeline system in question.

In the case of the Alberta System, it is not possible to directly assign costs to specific services because the nature of the System is such that the majority of its costs are joint or common costs (i.e., costs associated with facilities that are used to provide multiple services). Therefore, appropriate methodologies must be used to allocate costs to the various services provided by NGTL.

Cost allocations must reflect underlying cost relationships that have been demonstrated to be valid (e.g., unit transmission costs increase with distance, all other factors being held constant). Cost allocation methodologies must also be meaningful and acceptable to stakeholders, and must generally evolve in a way that reflects current public policy and market realities.

Q7. Has NGTL conducted a recent COS study?

A7. Yes. NGTL conducted a COS study based on its existing allocation methodology and the most current data then available (2004 COS Study). A copy of the 2004 COS Study is provided in Appendix 2A.

NGTL also conducted a second COS Study using the same data, but utilizing alternative cost allocation methodologies (Alternative Methodologies COS Study). A copy of the Alternative Methodologies COS Study is provided in Appendix 2B.

---

[3] EUB Decision 2003-051, page 27.

NGTL discusses the results of the 2004 COS Study and the Alternative Methodologies COS Study in sub-section 2.2.2.

Q8. What are the major cost components of the Alberta System revenue requirement?

A8. The Alberta System's primary function is the transmission of gas, which is a capital intensive activity. The majority of the Alberta System revenue requirement consequently consists of capital-related costs that can be directly assigned to the individual assets for metering, compression, or pipes. These categories collectively accounted for approximately 88% of the Alberta System's net book value (NBV) as of December 31, 2003. Metering, compression and pipe individually accounted for 8%, 21% and 71% respectively of this 88%. General plant and working capital accounted for the remaining 12% of the NBV.

For 2003, the direct costs were assigned as follows: 4.7% to metering, 15.0% to compression and 53.8% to pipe, collectively representing 73.5% of NGTL's total costs. The remaining 26.5% were non-direct costs related to General Plant and Working Capital, and General and Administration (G&A).

Q9. What are the major functions of the Alberta System?

A9. The Alberta System provides two major functions:

1. Transmission, which uses compression and pipes to transport gas, and is the primary function; and

2. Metering, which involves custody transfer gas measurement and related transactional functions (e.g., scheduling) being performed at each point on and from the System.

Q10. Has NGTL allocated costs to these functions in the 2004 COS Study, using the existing cost allocation methodology?

A10. Yes. NGTL followed a two step functionalization process in conducting the 2004 COS Study.

The first step was an assignment of the direct pipeline asset costs to the metering and transmission functions. Pipeline asset costs include depreciation, operating return, income and capital taxes, transportation-by-others (TBO), and municipal taxes. As transmission consists of compression and pipe, costs are first assigned to these components and aggregated into transmission by allocating compression costs to individual pipe assets using the power required to move gas through each piece of pipe, under standard operating conditions.

The second step was an allocation of the non-direct costs to the metering and transmission functions. Similar to the allocation process for pipeline asset costs, non-direct costs are allocated to compression and pipe and then aggregated into transmission by allocating compression costs to individual pipe assets using the power required to move gas through each piece of pipe, under standard operating conditions. All general plant costs are allocated to compression, pipe and metering by NBV. All working capital accounts, with the exception of line pack, which is allocated exclusively to pipes, are also allocated by NBV. Similarly, G&A costs, with the exception of maintenance costs, are allocated by NBV. Maintenance costs are allocated based on the historical splits of:

- 50% to compression;
- 35% to metering; and
- 15% to pipes.

Q11. Does NGTL provide separate metering and transmission services?

A11. No. NGTL provides transportation service which is segmented into two primary components: receipt and delivery. Rates for services within each of these components have either a metering and a transmission component or just a metering component. However, both receipt and delivery services are required in order to obtain a full path transportation service.

Receipt services, which consist of Firm Transportation-Receipt (FT-R), Firm Transportation-Receipt Non-Renewable (FT-RN) and Interruptible-Receipt (IT-R), provide shippers with the ability to deliver natural gas to the Alberta System at receipt points. FT-R is the primary Alberta System receipt service and accounts for approximately 75% of the Alberta System receipt revenue.

Delivery services are divided into export and intra-Alberta delivery services. Export delivery services consist of Firm Transportation-Delivery (FT-D), Firm Transportation-Delivery Winter (FT-DW), Short Term Firm Transportation-Delivery (STFT), and Interruptible-Delivery (IT-D). These services provide shippers with the ability to remove natural gas from the Alberta System at export delivery points. FT-D is the primary Alberta System export delivery service and accounts for approximately 85% of the Alberta System delivery revenue. Firm Transportation-Alberta (FT-A) is the primary intra-Alberta delivery service.

A combined receipt and delivery service, Firm Transportation-Alberta Points to Point (FT-P), is also available for intra-Alberta markets.

NGTL essentially provides transportation to two markets: ex-Alberta and intra-Alberta. Transportation to ex-Alberta markets is provided through the combination of receipt and export delivery services, with the main combination being FT-R and FT-D. Transportation to intra-Alberta markets is provided through the combination of receipt and intra-Alberta delivery services, with the main combination being FT-R and FT-A, and through FT-P service. The transportation to either market consists of a metering component to receive gas on to the system, a transmission component to move gas through the system, and a metering component to deliver gas from the system.

Q12. Please provide an overview of the Alberta System receipt and delivery services.

A12. As previously mentioned, NGTL provides services that are segmented into two primary components: receipt and delivery.

Receipt Services:

- FT-R is the primary receipt service. It is a demand service with a minimum initial contract term of three years, after which it can be renewed for a minimum term of one year. For terms less than three years, there is a 5% rate premium and for terms of five years or greater there is a 5% rate discount. Each receipt point has an individual rate that consists of a metering component and a transmission component. The transmission component is determined in accordance with the distance-diameter pricing methodology first approved by the Board in Decision 2000-6.[4] Individual receipt rates can vary by ± 8 cents/Mcf from the system average receipt rate.

- FT-RN is a demand service with a term of one year or less, no renewal rights and a rate equal to 110% of the FT-R rate for the respective receipt point.

- IT-R is an interruptible service and is priced at 115% of the FT-R rate for the respective receipt point.

Delivery Services:

- FT-D is the primary export delivery service. It is a demand service with a minimum initial contract term of one year, after which it can be renewed for a minimum term of one year. All export delivery points have the same rate that consists of a metering and transmission component.

- FT-DW is a demand service with an initial term of four years. Every two years the term can be extended to four years with the consent of NGTL. A maximum contract demand quantity of 35 MMcf/d is available between Empress and McNeill and a maximum contract demand quantity of 35 MMcf/d is available between A/BC and Alberta-Montana. FT-DW is not available at the other export delivery points. FT-DW is priced at 175% of the FT-D rate.

[4] Alberta Energy and Utilities Board Decision 2000-6, NOVA Gas Transmission Ltd., 1999 Products and Pricing, (February 4, 2000) (EUB Decision 2000-6).

- STFT is a non-renewable demand service available for terms of one, three, and five months during the winter season. NGTL determines the amount of capacity available for STFT based on operational and ambient conditions. STFT is a biddable service with a minimum price of 135% of the FT-D rate.

- IT-D is an interruptible service and is priced at 110% of the FT-D rate.

- FT-A is the primary intra-Alberta delivery service. It is a commodity service with a minimum term of one year, which can be renewed for a minimum term of one year. All intra-Alberta delivery points currently have the same rate, which consists of a metering component.

In 2003, FT-P service was implemented. This service provides shippers with the ability to deliver gas on the Alberta System at receipt points and remove it from the Alberta System at an intra-Alberta delivery point. It is an alternative transportation option to a combination of FT-R and FT-A services for intra-Alberta markets. It is a demand service with a minimum initial contract term of one year, after which it can be renewed for a minimum term of one year. For terms less than three years, there is a 5% rate premium and for terms of five years or greater, there is a 5% rate discount. Each FT-P contract has an individual rate that consists of a metering component to receive gas on the System, a metering component to deliver gas off the System, and a transmission component to move gas between the receipt and delivery points. The transmission component is based on the maximum distance between the receipt points and the delivery point identified on the schedule of service. The charge for the average transmission component for FT-P service is set to equal the charge for the average transmission component of FT-R service. Similar to FT-R service, where individual rates can vary by ± 8 cents/Mcf from the average FT-R rate, individual FT-P rates can vary by ± 8 cents/Mcf from the average FT-P rate.

Q13. Is the separation of receipt and delivery services on the Alberta System a significant fact?

A13. Yes. Separate receipt and delivery contracts create service flexibility and simplicity that customers value. This separation of receipt and delivery services allows for the “pooling” of gas on the Alberta System and contributes to the natural gas trading and marketing activities that occur via NOVA Inventory Transfer (NIT). It is important to note that this separation is not made based on any physical definition of receipt or delivery facilities or any physical location on the Alberta System.

Q14. What is the significance of the NIT pool?

A14. The Alberta gas market and its liquidity is influenced significantly by the single NIT pool. The NIT pool is one of the largest and most efficient markets in North America, with a physical natural gas flow of approximately 11 Bcf/d and commercial transactions in excess of 35 Bcf/d. This level of commerce provides a robust opportunity for price discovery, which ensures the establishment of pool prices for both spot and forward transactions. This pool includes supply from over 900 individual receipt points and provides delivery to over 100 intra-Alberta delivery points, as well as to six ex-Alberta pipelines that supply markets across North America. Over 200 customers have direct access to the NIT pool via NGTL accounts and numerous others can access the market via third party services. This broad accessibility maximizes the amount of gas available, places all suppliers on the same footing with the opportunity to find buyers, and places all buyers on the same footing with the opportunity to find supply.

NGTL’s rate design, terms and conditions of service, and business procedures are integral to the operation of NIT, which is greatly valued by NGTL’s customers.

Q15. How should metering costs be allocated to services?

A15. Metering is a function required by all transportation services available on the Alberta System. Gas is metered when it is received on the System and gas is metered when it is delivered from the System. As such, the metering function is included in the rates charged for all services, other than Interruptible Transportation-Storage (IT-S) and Firm

Transportation-Extraction (FT-X). NGTL determines the metering cost for each service on the basis of the overall system-average metering cost. This approach was extensively reviewed in NGTL's 2004 GRA Phase 2 proceeding, was generally accepted by NGTL's stakeholders, and was ultimately accepted by the Board as a reasonable approach.[5] Therefore, NGTL has not re-examined metering cost allocation in this Application.

Q16. Why is there no metering function included in the IT-S or FT-X services?

A16. These services provide broad industry benefits. Therefore, it could be argued that costs associated with them are appropriately recovered through other transportation services.

NGTL also understands through consultation with customers and the extensive review in NGTL's 2004 Phase 2 proceeding, that the majority of customers are not in favour of explicit rates for IT-S or FT-X services at this time. Consequently, NGTL does not allocate metering costs to these services under its existing cost allocation methodology.

Q17. How should transmission costs be allocated to services?

A17. Ideally, each service should have a transmission component that reflects its share of the transmission function. However, as previously mentioned, NGTL divides its services into receipt, which allows gas on the System, and delivery, which allows gas off the System, without having any physical demarcation between receipt and delivery service upon which the assignment of transmission costs between the two services can be based. In addition, the Alberta System is a highly integrated system, with the majority of its transmission costs being joint or common costs, so it is not possible to determine the actual costs of providing particular services. Consequently, it is appropriate to aggregate the transmission costs of facilities and utilize cost allocation methodologies to determine service rates.

Q18. What methodologies has NGTL used to allocate transmission costs to services?

A18. NGTL has historically used a distance of haul methodology to validate that the 50/50 split of transmission costs on a unit basis to receipt and delivery services is reasonable.

---

[5] EUB Decision 2004-097, page 18.

NGTL provided a 2003 DOH Study as part of its 2004 GRA Phase 2 Application. NGTL also provided as part of its 2004 GRA Phase 2 Application a COH study for comparison purposes.

Q19. Has NGTL updated its 2003 DOH study?

A19. Yes. NGTL completed a 2004 DOH Study based on the revised DOH methodology approved by the EUB in Decision 2004-097. A copy of the 2004 DOH Study is provided in Appendix 2A. The Study was conducted in late 2004, as part of NGTL's preparation of this Application. It is therefore based on 2003 data, which was the most current data available at that time.

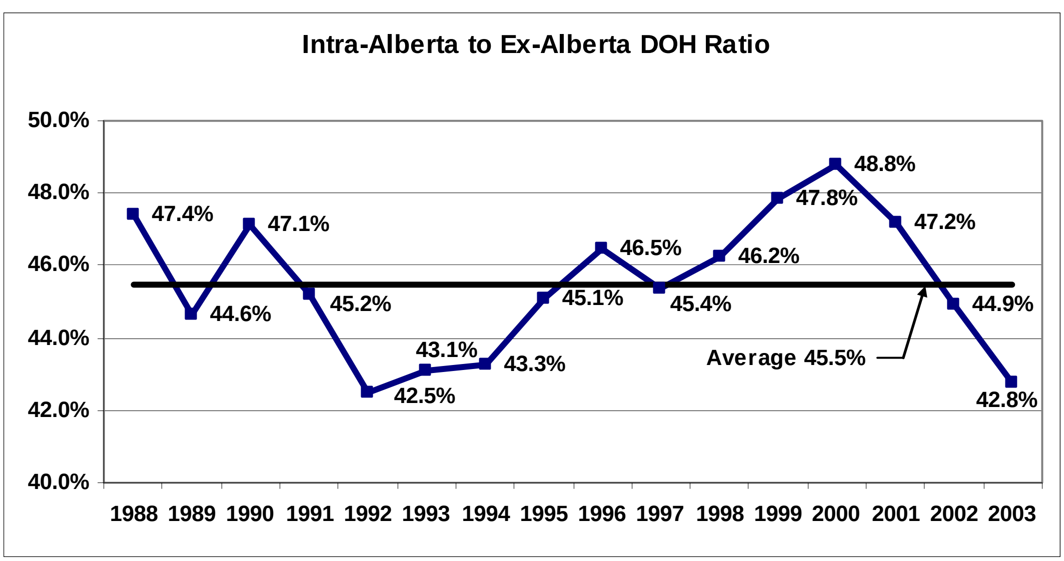
The average 2003 DOH was: 239 km for intra-Alberta deliveries; 559 km for ex-Alberta deliveries; and 517 km for all deliveries (intra-Alberta and ex-Alberta).

Thus, the average intra-Alberta DOH was 42.8% of the average DOH for ex-Alberta deliveries in 2003.

Q20. How does this result compare to the results of previous years' DOH studies?

A20. Figure 2.2.1-1 shows the annual DOH results from 1988 to 2003.

Figure 2.2.1-1



The average intra-Alberta to ex-Alberta ratio has ranged from a low of 42.5% in 1992 to a high of 48.8% in 2000. The 16-year average is 45.5%.

Q21. Has NGTL forecast the DOH for 2004 or 2005?

A21. No. NGTL's DOH studies examine historical data. NGTL does not have a model to forecast DOH. The DOH will depend on the actual volumes received at 900 + receipt stations and the actual volumes delivered to 100 + delivery stations, as well as the actual pipe connectivity and hydraulics used to transport gas between the various receipt and delivery points. Currently, NGTL cannot forecast these factors without making significant simplifying assumptions that may then generate unreliable results.

Q22. Has NGTL updated its COH study as directed by the Board in Decision 2004-097?

A22. Yes. NGTL updated its COH study using 2003 data. As earlier explained, this was the most current data available when NGTL conducted the study in late 2004. Any acquisitions, expansions and extensions that were added to the Alberta System since December 31, 2003 are therefore not included in the 2004 COH Study. The updated 2004 COH Study is included in Appendix 2C and contains a comprehensive description of the methodology employed.

Q23. Did NGTL include the Simmons Pipeline assets acquired in 2004 in its 2004 COH Study?

A23. No. The 2004 COH Study is an historical examination of the Alberta System for 2003. As the Simmons Pipeline facilities were not part of the Alberta System until late 2004, these facilities were not included in the 2004 COH Study. However, due to the relatively small distance of pipe and small volumes relative to the existing intra-Alberta deliveries, NGTL believes that these assets will not have a material effect on the 2004 COH. NGTL has included additional analysis on the Simmons Pipeline facilities in Section 2.4 of the Application.

Q24. What are the results of the 2004 COH Study?

A24. The results indicate that the average cost of haul in 2003 was 673 for intra-Alberta deliveries and 936 for ex-Alberta deliveries.

The average intra-Alberta COH is 71.9% of the average COH for ex-Alberta deliveries. This is a 6.0% increase from the 2002 COH ratio.

Q25. How does the 2004 COH Study compare to the 2004 DOH Study?

A25. The COH Study is similar to the DOH Study except that it also takes into account economies of scale of the facilities that are used to transport gas. For the COH analysis, facility costs have been accounted-for by applying a relative cost index against each pipe diameter. Thus, the COH study provides a measure of both the distance the gas travels, as well as the costs associated with the facilities used to provide the transportation.

The intra-Alberta COH to ex-Alberta COH ratio is higher than the intra-Alberta DOH to ex-Alberta DOH ratio because, on average, intra-Alberta deliveries utilize a higher percentage of smaller diameter pipe than ex-Alberta deliveries. The change in the COH ratio from 2002 to 2003 is also greater than the relative change in the DOH ratio from 2002 to 2003, which was only 4.9%.

Q26. Has NGTL examined any allocation of transmission costs based on COH in this Application?

A26. No. However, in its 2004 GRA Phase 2 (Section 2.5.2-3), NGTL presented and discussed five COS alternatives based on its 2003 DOH study and five alternatives based on its 2003 COH study.

The first DOH alternative was the DOH methodology that is currently used. It was called the revised DOH methodology because NGTL had revised the process it previously used to calculate the DOH for the delivery points. This methodology allocates transmission costs between receipt and delivery such that:

a) the transmission component of the average FT-R rate is set equal to the transmission component of the FT-D rate; and

b) the average transmission component of the service rates (FT-R + FT-D) required to deliver gas to an export market is twice the average transmission component of the service rates (FT-R + FT-A) to deliver gas to an intra-Alberta market. This split between ex- and intra-Alberta markets is based on the DOH study that shows that on average the distance gas travels to an export market is approximately twice the distance gas travels to an intra-Alberta market.

The second, third and fourth DOH alternatives segmented the Alberta System into mainline and lateral components and used the DOH methodology to allocate mainline costs between receipt and delivery. The only difference between these alternatives was the definition of mainline facilities.

The fifth DOH alternative changed the methodology used to determine the DOH ratio between export and intra markets by excluding extraction stations from the calculation and then used this DOH ratio to set the average transmission component of the service rates (FT-R + FT-D) required to deliver gas to an export market in relation to the average transmission component of the service rates (FT-R + FT-A) required to deliver gas to an intra-Alberta market.

The first of the five COH alternatives used the COH ratio between ex-Alberta and intra-Alberta to set the transmission component of the service rates (FT-R + FT-D) required to deliver gas to an export market in relation to the average transmission component of the service rates (FT-R + FT-A) required to deliver gas to an intra-Alberta market.

The second, third and fourth COH alternatives segmented the Alberta System into mainline and lateral components and used the COH methodology to allocate mainline costs between receipt and delivery. The only difference between these alternatives was the definition of mainline facilities.

The last COH alternative changed the methodology used to determine the COH ratio between export and intra markets by excluding extraction stations from the calculation and then used this COH ratio to set the average transmission component of the service rates (FT-R + FT-D) required to deliver gas to an export market in relation to the transmission component of the service rates (FT-R + FT-A) required to deliver gas to an intra market.

The changes in service rates resulting from the application of these various DOH and COH alternatives was provided in Table 2.5.3-2 of the 2004 GRA Phase 2. That table is reproduced here as Table 2.2.1-1.

Table 2.2.1-1
Change in Illustrative 2004 Rates Resulting from Application of Cost Allocation Using the DOH and COH Methodologies to Rates Determination
(cents/Mcf/day)

Using DOH	**Revised Methodology**	**Alternative 1a) Functional Mainline Definition**	**Alternative 1b) Physical Mainline Definition (>= 24")**	**Alternative 1c) Physical Mainline Definition (>= 12")**	**Alternative 2 Excluding Extraction**
Receipt (FT-R)[1]	0.0	0.2	3.1	(0.1)	(11.6)
Border delivery (FT-D)[1]	0.0	(0.2)	(3.1)	1.0	11.6
Total Ex-Alberta Rate[2]	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Intra delivery (FT-A)	0.0	0.0	0.0	0.0	0.0
Total Intra-Alberta Rate[3]	**0.0**	**0.2**	**3.1**	**(0.1)**	**(11.6)**
Using COH					
Receipt (FT-R)[1]	6.4	1.3	3.6	4.4	1.4
Border delivery (FT-D)[1]	(6.4)	(1.3)	(3.6)	(4.4)	(1.4)
Total Ex-Alberta Rate[2]	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Intra delivery (FT-A)	0.0	0.0	0.0	0.0	0.0
Total Intra-Alberta Rate[3]	**6.4**	**1.3**	**3.6**	**4.4**	**1.4**

Notes:
[1] FT-R and FT-D rates quoted include the metering charge.
[2] Total ex-Alberta rate is the sum of the FT-R and FT-D rates.
[3] Total intra-Alberta rate is the sum of the FT-R and FT-A rates.
Totals may not add due to rounding.

The Revised Methodology (Column 2) was found appropriate by the Board in Decision 2004-097 and is now NGTL's existing methodology. As is evident from Table 2.2.1-1, all of these methodologies result in a reallocation of costs between receipt and delivery services. Depending on the alternative selected, the average FT-R rate could vary from -11.6 cents/Mcf to +6.4 cents/Mcf and the FT-D rate could vary from -6.4 cents/Mcf to +11.6 cents/Mcf, each compared to the rate calculated using the revised methodology. Although the numbers would be different based on 2005 data, the relative changes would be similar.

The COH methodology has some merit for use in allocation of transmission costs to services because it takes into account economies of scale as well as distance. However, the yearly variability associated with use of the COH methodology appears to be greater than that which results from use of the DOH methodology. This could result in greater rate volatility.

Further, consideration needs to be given to how the benefits associated with the economies of scale inherent to the Alberta System are shared by the customer base. Due to the highly integrated nature of the Alberta System, cost allocation based only on a COH methodology may not provide an appropriate sharing of the benefits of economies of scale. This concern was noted by the Board in Decision 2004-097:

> However, the Board is concerned that utilization of the COH methodology may not appropriately allocate the benefits of the economies of scale of the NGTL System to all customers.[6]

Finally, the majority of NGTL's customers and interested parties continue to support the use of the DOH for the purpose of allocating transmission costs between receipt and delivery services. The Board acknowledged this support in Decision 2004-097:

> The majority of NGTL shippers continue to support NGTL's DOH methodology, with only ATCO recommending the utilization of NGTL's COH methodology. The Board therefore considers it appropriate to use the DOH study as a primary rate design methodology at this time, with the COH study acting as an

[6] EUB Decision 2004-097, page 10.

> alternative mechanism for comparison purposes, as well as a proxy for costs for receipt point specific rates.[7]

As a result, NGTL does not examine any allocations of transmission costs based on a COH methodology in this Application.

Q27. Did NGTL examine cost allocation methodologies other than DOH and COH?

A27. No. There are numerous other cost allocation methodologies that could be applied. One alternative NGTL believes may have merit for future consideration is to functionalize receipt services into mainline and lateral components. Under such an approach, the rates would be based on a more detailed segregation of costs than the existing methodologies.

Another alternative would be to calculate export point specific delivery prices using an analogous methodology to the existing receipt point specific pricing algorithm. With this methodology, the individual export point delivery rates would be based on a more detailed segregation of costs than the existing flat rate approach. However, NGTL has not developed these concepts in sufficient detail to properly evaluate them further in this Application.

Q28. Did NGTL examine methodologies that allocate costs to customer classes?

A28. No. Methodologies that would allocate costs to customer classes are not appropriate or applicable to the Alberta System. NGTL does not have customer classes that can be solely distinguished by the type of service that they use. All customers groups can and do contract for different service categories. Producers, marketers, end-users and utilities all utilize various combinations of receipt, export delivery, and intra-Alberta delivery services. This structure is substantially different from that of local distribution companies, where service design based on customer segmentation is typical.

Dr. Gaske also considers these issues in his testimony and reaches comparable conclusions.

---

[7] Ibid.

2.2.2 Cost of Service Analysis

Q29. Is the 2004 COS Study, identical to the 2003 COS Study provided in NGTL's 2004 GRA?

A29. No. In addition to updating the COS Study to incorporate 2003 cost information, NGTL made several changes to simplify the cost allocation and to make the Study more comprehensive. First, NGTL simplified the methodologies for allocating non-direct costs by using net book value in most instances. Secondly, the 2004 DOH Study was incorporated as part of the 2004 COS Study. Finally, the 2004 COS Study was expanded to include the allocation of costs to all tariff services for the test year.

Q30. Please describe the cost allocation methodology used in the 2004 COS Study and contrast it to the six alternatives examined in the Alternative Methodologies COS Study.

A30. The existing methodology, which is fully described in the 2004 COS Study allocates transmission costs based on a 2:1 relationship between export and intra-Alberta markets and accounts for the transmission costs associated with deliveries to intra-Alberta markets in the FT-R rate. This split between ex-Alberta and intra-Alberta markets is validated by the 2004 DOH Study, which shows that the average distance gas travels to the export market is approximately twice the average distance gas travels to the intra-Alberta market. As all services except IT-S and FT-X include a system average metering component, this methodology produces an average FT-R rate that is equal to the FT-D rate.

In addition to the existing methodology, NGTL has examined six alternative cost allocation methodologies in the Alternative Methodologies COS Study. NGTL selected these six alternatives because it believes they represent a reasonable range of alternatives that respond to the Board's directives in Decision 2004-097 that NGTL consider alternative cost allocation methodologies. NGTL also believes that these alternatives provide a basis against which parties can assess the reasonableness of NGTL's existing rate design.

The first set of these alternatives (1 to 3) retains the key feature of a DOH-based split of transmission costs between intra-Alberta and ex-Alberta, while varying the amount of transmission costs specifically allocated to the FT-A service.

Alternatives 1 to 3 are similar to the existing methodology in that they incorporate a system average metering component in all services other than IT-S and FT-X. They are all different from the existing methodology in that the relationship of transmission costs between export and intra-Alberta markets has been changed from 2:1 to 2.2:1, reflecting the long term average DOH which yields an intra-Alberta to ex-Alberta DOH ratio of 45.5%. They differ amongst themselves with respect to the direct transmission charge incorporated into the FT-A rate. The direct transmission charge should be based on the costs to provide that service. Therefore, transmission costs associated with services other than intra-Alberta delivery should be excluded from the FT-A rate. As a result, NGTL excluded the cost for transmission facilities more directly associated with export, storage, and extraction from the FT-A rate in each of these alternatives. This left the facilities that are only associated with receipt and intra-Alberta delivery services. A breakdown of these costs is provided in sub-section 2.4.2. As these facilities are equally associated with receipt services as intra-Alberta delivery services, some of the costs should be accounted for in the rates of receipt services. NGTL presents two alternatives, one with inclusion of only NGTL facilities and the other with those same NGTL facilities plus costs associated with intra-Alberta TBO agreements. To recognize the balance between receipt and delivery, NGTL has allocated 50% of the costs associated with these facilities to receipt services, and included the remaining 50% of the costs associated with these facilities in the FT-A rate.

Table 2.2.2-1 summarizes the differences in allocation methodologies between Alternatives 1 through 3.

Table 2.2.2-1
Comparison of Alternatives 1 to 3

Cost Allocation	Alternative 1	Alternative 2	Alternative 3
Intra-Alberta/Ex-Alberta DOH Ratio	45.5%	45.5%	45.5%
Percent of the COS for transmission facilities not associated with export, storage, or extraction included in the FT-A rate	0%	50%	50%
Percent of the cost for the Ventures, ATCO and Kearl Lake TBOs included in the FT-A rate	0%	0%	50%

The second set of these alternatives (4 to 6) retain the DOH basis, but without a split between intra-Alberta and ex-Alberta being a prerequisite step in the determination of rates. Instead, an allocation of costs to services based on volume and distance is employed, with the variation in these alternatives being in the selection of services which are considered primary. In Alternatives 4, 5 and 6, NGTL specifically allocates the revenue requirement to each primary service based on that service's share of the total volume x distance units of all primary services. These alternatives were developed consistent with the response to an undertaking given to the Board in the 2004 GRA proceeding,[8] and do not rely on the traditional NGTL approach of a split between intra and ex-Alberta based on DOH. In this undertaking NGTL was requested to allocate transmission costs based on a DOH-volume (or volume-distance) index prepared by the Board using NGTL's DOH study and forecast volumes.[9] The main difference between each alternative is which services are considered primary. Table 2.2.2-2 summarizes these alternatives.

[8] Response to undertaking at transcript reference 4T610, Exhibit 040-25, NOVA Gas Transmission Ltd., 2004 GRA Phase 2 proceeding.
[9] Exhibit 040-14, NOVA Gas Transmission Ltd., 2004 GRA Phase 2 proceeding.

Table 2.2.2-2
Comparison of Alternatives 4 to 6

Alternative	Primary Services	Secondary Services
4	FT-R; FT-D; FT-A	FT-RN; IT-R; FT-P FT-DW; STFT; IT-D FCS
5	FT-R; FT-D; FT-P	FT-RN; IT-R FT-DW; STFT; IT-D
6	FT-R; FT-D; FT-A; FT-P; FT-X; IT-S	FT-RN; IT-R FT-DW; STFT; IT-D FCS

In Alternative 5 the FT-A service has been eliminated. Without an FT-A service there is no requirement to allocate a transmission component to it. Instead, intra-Alberta service would be provided through FT-P service. A detailed description and explanation of the allocation of the revenue requirement to tariff services for each alternative analyzed, along with illustrative rate calculations and a table of illustrative rates, has been included in Appendix 2B. In addition, Tables 2.2.2-3 to 2.2.2-5 summarize the results for the alternatives.

Q31. Please summarize the results of NGTL's analysis of the cost allocation methodologies considered in the Alternative Methodologies COS Study.

A31. Table 2.2.2-3 shows illustrative rates and key ratios that result from the application of the existing cost allocation methodology and the six alternatives which NGTL examined. Table 2.2.2-4 shows the difference between the rates generated by the existing methodology and the alternatives. Table 2.2.2-5 shows the same data shown in Table 2.2.2-4, but on a percentage basis.

Table 2.2.2-3
Illustrative Rates and Ratios from Application of Existing and Alternative COS Methodologies
(cents/Mcf)

		Alternative					
Rate/Ratio	Existing	1	2	3	4	5	6
Average FT-R	15.51	14.37	13.94	12.88	14.71	14.75	13.97
FT-D	15.51	16.93	17.41	18.61	16.62	16.35	15.38
FT-A	1.42	1.42	1.87	3.00	1.34	n/a	3.37
Average FT-P	15.89	14.75	14.32	13.25	15.09	5.63	6.11
FT-X	-	-	-	-	-	-	14.88
IT-S	-	-	-	-	-	-	3.13
Intra Rate	16.93	15.79	15.81	15.88	16.05	5.63	17.34
Export Rate	31.02	31.30	31.35	31.49	31.33	31.10	29.35
Intra/Ex Ratio	54.6%	50.4%	50.4%	50.4%	51.2%	18.1%	59.1%
Intra Transmission	14.09	12.95	12.97	13.04	13.21	2.79	14.50
Ex Transmission	28.18	28.46	28.51	28.65	28.49	28.26	26.51
Intra/Ex Ratio	50.0%	45.5%	45.5%	45.5%	46.4%	9.9%	54.7%
Receipt Rate	15.51	14.37	13.94	12.88	14.71	14.75	13.97
Export Rate	31.02	31.30	31.35	31.49	31.33	31.10	29.35
Receipt/Ex Ratio	50.0%	45.9%	44.5%	40.9%	47.0%	47.4%	47.6%

Table 2.2.2-4
Change in Existing Illustrative Rates and Ratios from Application of Alternative COS Methodologies
(cents/Mcf)

		Alternative					
Rate/Ratio	Existing	1	2	3	4	5	6
Average FT-R	-	(1.14)	(1.57)	(2.63)	(0.80)	(0.76)	(1.54)
FT-D	-	1.42	1.90	3.10	1.11	0.84	(0.13)
FT-A	-	-	0.45	1.58	(0.08)	n/a	1.95
Average FT-P	-	(1.14)	(1.57)	(2.64)	(0.80)	(10.26)	(9.78)
FT-X	-	-	-	-	-	-	14.88
IT-S	-	-	-	-	-	-	3.13
Intra Rate	-	(1.14)	(1.12)	(1.05)	(0.88)	(11.30)	0.41
Export Rate	-	0.28	0.33	0.47	0.31	0.08	(1.67)
Intra/Ex Ratio (percentage points)	-	(4.13)	(4.15)	(4.15)	(3.35)	(36.47)	4.50
Intra Transmission	-	(1.14)	(1.12)	(1.05)	(0.88)	(11.30)	0.41
Ex Transmission	-	0.28	0.33	0.47	0.31	0.08	(1.67)
Intra/Ex Ratio (percentage points)	-	(4.50)	(4.51)	(4.49)	(3.63)	(40.13)	4.70
Receipt Rate	-	(1.14)	(1.57)	(2.63)	(0.80)	(0.76)	(1.54)
Export Rate	-	0.28	0.33	0.47	0.31	0.08	(1.67)
Receipt/Ex Ratio (percentage)	-	(4.09)	(5.53)	(9.10)	(3.05)	(2.57)	(2.40)

Table 2.2.2-5
Change in Existing Illustrative Rates and Ratios from Application of Alternative COS Methodologies

		Alternative					
Rate/Ratio	Existing	1	2	3	4	5	6
Average FT-R	0%	-7%	-10%	-17%	-5%	-5%	-10%
FT-D	0%	9%	12%	20%	7%	5%	-1%
FT-A	0%	0%	32%	111%	-6%	n/a	137%
Average FT-P	0%	-7%	-10%	-17%	-5%	-65%	-62%
FT-X	0%	0%	0%	0%	0%	0%	n/a
IT-S	0%	0%	0%	0%	0%	0%	n/a
Intra Rate	0%	-7%	-7%	-6%	-5%	-67%	2%
Export Rate	0%	1%	1%	2%	1%	0%	-5%
Intra/Ex Ratio	0%	-8%	-8%	-8%	-6%	-67%	8%
Intra Transmission	0%	-8%	-8%	-7%	-6%	-80%	3%
Ex Transmission	0%	1%	1%	2%	1%	0%	-6%
Intra/Ex Ratio	0%	-9%	-9%	-9%	-7%	-80%	9%
Receipt Rate	0%	-7%	-10%	-17%	-5%	-5%	-10%
Export Rate	0%	1%	1%	2%	1%	0%	-5%
Receipt/Ex Ratio	0%	-8%	-11%	-18%	-6%	-5%	-5%

The allocation of transmission costs for Alternatives 1 to 3 is 45.5% to the intra-Alberta FT-R/FT-A service combination and 54.5% to the ex-Alberta FT-R/FT-D service combination.

Alternative 1 illustrates the impact of changing only the intra-Alberta/ex-Alberta DOH ratio. Alternative 1 has no transmission component in the FT-A rate, produces an average FT-R rate that is approximately 7% lower than the existing methodology, and produces an FT-D rate that is approximately 9% higher than the existing methodology.

Alternative 2 recovers 50% of the transmission costs not associated with export, storage or extraction directly through an FT-A rate of 1.87 cents/Mcf. This results in average FT-R and FT-D rates that are approximately 10% lower and 12% higher respectively, from the existing methodology.

Alternative 3 recovers 50% of the transmission costs not associated with export, storage or extraction and 50% of the Ventures, ATCO and Kearl Lake TBO costs directly through an FT-A rate of 3.0 cents/Mcf. This alternative produces average FT-R and FT-D rates that are 17% lower and 20% higher respectively, than those under the existing methodology.

Alternative 4 considers FT-R, FT-D and FT-A to be primary services. This alternative produces an FT-A rate of 1.34 cents/Mcf and average FT-R and FT-D rates that are 5% lower and 7% higher respectively, than those under the existing methodology.

Alternative 5 considers FT-R, FT-D and FT-P to be primary services. In this alternative, it is assumed that FT-A service is not available and all intra-Alberta volumes are contracted under FT-P service. As FT-P service is classified as a primary service, the portion of the revenue requirement allocated to it is based on its relative share of volume x distance units. This results in a decrease to the average FT-P rate of 65% from the existing methodology. It also results in the average FT-R and FT-D rates being 5% lower and 5% higher respectively, than those under the existing methodology. Perhaps more importantly, without an FT-A service, intra-Alberta markets would not have access to NIT and the requirement for Facility Connection Service (FCS) Minimum Annual Volume (MAV) could be eliminated.

Alternative 6 allocates costs to all service categories. FT-X and IT-S services have been included as primary services with FT-R, FT-D, FT-A and FT-P services. This results in an FT-A rate of 3.37 cents/Mcf, which is within 2 cents/Mcf of the existing methodology, and average FT-P, FT-R and FT-D rates that are 62% lower, 10% lower and 1% lower respectively, than the existing methodology. However the major change under this alternative is the introduction of an FT-X rate of 14.88 cents/Mcf and an IT-S rate of 3.13 cents/Mcf, both of which are substantially higher than the existing methodology.

With the exception of Alternative 5, the relationship between the total intra-Alberta rate (FT-R + FT-A) and the total export rate (FT-R + FT-D) varies from 50.4% to 59.1% and the transmission component between the intra-Alberta rate and the export rate varies between 45.5% and 54.7%. The change for Alternative 5 is substantive because of the elimination of FT-A service. With this result, all intra-Alberta markets would have to be served with FT-P service, which would substantially lower the intra-Alberta rate.

Alternative 3 results in the greatest change between the receipt and export rate with the receipt rate being only 40.9% of the export rate. Alternative 3 also produces the largest rate changes overall, compared to the rates derived from the existing methodology, with the FT-A rate increasing by 111%, the FT-D rate increasing by 20%, and the average FT-R and FT-P rates decreasing by 17%.

Q32. What is NGTL's assessment of these results?

A32. All of these alternatives result in a reallocation of costs amongst receipt, export delivery and intra-Alberta delivery services.

By using the long term average DOH to allocate transmission costs, Alternative 1 allocates a greater share of the costs to transport gas to export markets to the delivery services and a lower share to the receipt services. This would have distributional effects on existing customers. This alternative may be a more precisely calculated allocation than the current methodology, but it would increase rate uncertainty since the long term average DOH will vary annually.

By allocating a portion of the intra-Alberta transmission costs directly to the FT-A rate in Alternative 2, an even greater share of the costs to transport gas to the export markets has been allocated to delivery services. Alternative 2 also results in a greater share of the costs to transport gas to intra-Alberta markets being allocated to the delivery services. Again, this will have distributional effects on an even greater number of existing customers than Alternative 1.

Alternative 3 results in a significant reallocation of costs to the delivery services. The illustrative FT-D rate of 18.61 cents/Mcf is greater than any historical FT-D rate. This result could lead to border bypass. This raises the prospect of a greater use of load retention services and/or an adjustment to the floor and ceiling receipt rates. Similarly, the direct increase of 111% to the FT-A rate is substantial, and may provide incentive for intra-Alberta bypass. This alternative would also have distributional effects similar to Alternatives 1 and 2, but of a greater magnitude.

Alternative 4 produces rates that are within 10% of the illustrative rates derived from the existing methodology for all services. Thus this alternative will have the least distributional impact on existing customers. The FT-A rate under this alternative includes a direct transmission component, however it is a negative amount. This results from the fact that FT-P and FCS services generate sufficient revenue to reduce the share of intra-Alberta delivery costs to be collected by FT-A to be less than the metering costs.

Alternative 5 produces the most precisely measured allocation of transmission costs to the intra-Alberta delivery service. This results from eliminating the FT-A service and requiring intra-Alberta delivery services to be provided only by FT-P service. As the FT-P service is a full path service based on the distance between the receipt points and the delivery point, a better determination of actual costs can be made. However, adopting this approach would require removal of all intra-Alberta deliveries from NIT.

Alternative 6 is the only methodology that allocates costs to all service categories. However, by including FT-P as a primary service, it greatly reduces the amount of revenue that this service would be required to generate, resulting in a significantly lower rate. This would better align the FT-P rate structure with FT-A (the other intra-Alberta delivery service) but skew the rate structure from FT-R (the other intra-Alberta receipt service). Alternative 6 introduces significant rates for FT-X and IT-S services, which most stakeholders and NGTL believe are not appropriate at this time.

The existing methodology allocates all transmission costs for service to intra-Alberta markets to the receipt services. This results in the receipt shipper directly paying for all intra-Alberta transmission costs and the delivery shipper having no direct share. However, in the end, when the delivery shipper purchases gas, the appropriate transmission costs will be indirectly accounted for by the delivery shipper. The same concept applies to the service for export markets. Here the delivery shipper accounts for half of the transmission costs directly through its delivery service and half of the transmission costs indirectly when the gas is purchased from the receipt shipper. Obviously, maintaining this methodology would have no distributional impacts.

Q33. What does NGTL conclude regarding the appropriateness of the various cost allocation methodologies examined?

A33. It is evident that under all cost allocation methodologies examined here, including the existing methodology, costs are fully allocated insofar as the methodologies would result in rates that facilitate collection of the entire revenue requirement. Costs are also categorized and functionalized in a manner that reflects the integrated nature of the Alberta System. The analysis also provides further information as a basis for considering rate design issues, including competition and public policy objectives. Consequently, the basic objectives of a cost of service study have been met.

It is also evident that any change in cost allocation methodology would alter the rates paid by customers. Several of the alternatives, if adopted, would have significant distributional effects on Alberta System customers.

In summary, while NGTL considers all of the alternatives to have some merit, no one methodology is clearly superior to the others. However, unlike the alternatives, the existing methodology and its impacts are well understood and acceptable to the majority of NGTL’s stakeholders. Accordingly, NGTL believes there is no compelling reason to prefer one of the alternatives over another, or to otherwise deviate from the existing cost allocation methodology for 2005.

2.3 RATE DESIGN

Q34. What is the purpose of the evidence in this sub-section?

A34. The purpose of this evidence is to assess the NGTL rate design against generally accepted rate design criteria. As part of this assessment NGTL also responds to the Board's consideration of an appropriate intra-Alberta rate.

Q35. Please provide an overview of the existing rate design methodology for the Alberta System.

A35. A detailed description of the Alberta System cost allocation and rate design methodology is provided in NGTL's 2004 COS Study. The 2004 COS Study encompasses both cost allocation and rate design as these are the components of a highly integrated and iterative process to which there is no clearly identifiable starting point. For example, it is not possible to identify costs for particular services until particular services are identified, nor is it possible to structure rates that are cost reflective without understanding the underlying cost structures. However, the end point is very clearly defined with the determination of final rates for each service offered which is considered a rate design activity. As a result the last section (Section 7) of the COS study provides a detailed description of the process used to determine the final rates.

The existing rate design methodology fully allocates the revenue requirement to all tariff services using the cost allocations developed in the COS study. In essence, the rate design methodology ensures that the following cost relationships are maintained:

a) the average transmission component of the service rate (FT-R + FT-D) required to deliver gas to the export market is twice the average transmission component of the service (FT-R + FT-A) rate to deliver gas to the intra-Alberta market.

b) the transmission component of the average FT-R rate is equal to the transmission component of the FT-D rate; and

c) The rate for every service, except FT-X and IT-S services, includes a metering component to account for metering costs.

The rate design also maintains the relationships between the primary services and their associated secondary services.

Figure 5.1-1 in Section 5 of this Application provides an overview of the rate calculation process for 2005.

Q36. What changes were introduced to the NGTL rate design in 2003?

A36. Upon receiving Board Decision 2003-051, NGTL implemented several significant changes to its rates and services. These included:

- the introduction of a new FT-P service for intra-Alberta transportation;
- an explicit toll for FT-A service;
- an increased MAV threshold to increase accountability for facilities associated with intra-Alberta delivery, extraction, and storage points; and
- the introduction of a new extension annual volume (EAV) obligation for mainline extensions associated with intra-Alberta deliveries.

FT-P service provides an intra-Alberta transportation service for customers with a rate that reflects the costs required to provide the service and the attributes associated with it. As the rate for the FT-P service is based on the full path cost of providing service from specific receipt points to a specific delivery point, users of this service are accountable for the costs associated with the transportation of their gas.

In effect, FT-P service represents a combination of FT-R service and FT-A service. Therefore, the FT-P rate is similar to the combined FT-R and FT-A rates. Specifically, the FT-P rate includes the receipt metering and transmission components of costs, which is similar to the FT-R rate, and the intra-Alberta metering costs, which is similar to the FT-A rate.

FT-A service, in conjunction with FT-R service, provides the alternative for receipt, transmission and delivery to intra-Alberta markets. Metering costs that had previously been recovered via other transportation services were now recovered directly from the customer that holds the FT-A contract. FT-A service does not have a transmission component associated with its rate due to the integrated nature of the Alberta System. Transmission costs for shared facilities (e.g., the facilities used for multiple services such as both receipt and intra-Alberta delivery) are included in the FT-R rate. By virtue of this component of the FT-R rate, which must be incurred to effect an FT-A delivery, a transmission charge is in fact associated with such delivery.

The change to the MAV and the introduction of the EAV provide increased customer cost accountability for intra-Alberta deliveries.

Q37. What criteria are used in the assessment of the appropriateness of the rate change?

A37. The following criteria espoused by Professor Bonbright [10] have been commonly used for structuring rates:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretations.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amount of use.

[10] James C. Bonbright, Principles of Public Utility Rates, 1961, page 291.

Q38. What relative weighting should be given to each of these criteria in assessing a rate design?

A38. It is difficult to ascribe a specific weighting to each of these criteria. NGTL believes that a rate design must evolve to meet the changing dynamics of the marketplace and reflect, at any given time, a balance of interests among stakeholders. As such, the relative importance of criteria may change over time.

The Board recognized in Decision U96055 that the weight to be assigned to these criteria will reflect a balance of interests. It stated:

> …the basic attributes of an appropriate rate design include simplicity, understandability and public acceptability; freedom from controversy; effectiveness in achieving revenue sufficiency and providing revenue and rate stability; fairness in apportionment of costs and avoidance of undue discrimination; and the encouragement of efficiency. <u>The weight to be given to each of these characteristics will depend largely on the desired balance between various goals, objectives and interests.</u>[11] [Emphasis added]

The various goals, objectives and interests of stakeholders were considered in the consultations that led to past settlements that form the basis of NGTL's existing rate design. As such, an appropriate balance was struck between these criteria at the time.

Q39. Has NGTL assessed the existing rate design and the alternatives against these criteria?

A39. No. However, Dr. Gaske has conducted such an assessment at NGTL's request. It is Dr. Gaske's view that the existing rate design satisfies these criteria. He also concludes that implementation of any alternative would ultimately be determined by weighing the importance of various principles such as stability, the distributional impacts on customers and competitive considerations. NGTL agrees with Dr. Gaske's views.

[11] Alberta Energy and Utilities Board Decision U96055, NOVA Gas Transmission Ltd. 1995 General Rate Application Phase II (January 12, 1995), pages 35 and 36.

Q40. Is the existing rate design still appropriate for 2005?

A40. Yes. NGTL believes that the existing rate design remains appropriate for 2005.

It is a reasonable design for the Alberta System based on sound allocation methodologies and satisfies generally accepted rate design criteria.

Further, NGTL understands that the majority of its stakeholders continue to support the existing rate design for 2005. This design reflects a significant collaborative effort among NGTL's diverse stakeholders and required compromise of competing interests.

Q41. Is the NGTL rate design expected to remain as it is for the foreseeable future?

A41. The NGTL rate design will continue to evolve as a function of changes in the business environment. NGTL expects to have ongoing discussions with stakeholders through its collaborative process and to bring forward changes for Board approval from time to time.

Q42. Is there any other consideration for the current review of the NGTL rate design?

A42. Yes. In Decision 2004-097 the Board suggested that an intra-Alberta toll of approximately 4 cents/Mcf might be reasonable. Specifically, the Board stated:

> With respect to the current record, the proposals for transmission costs to be included in the FT-A rate range from zero (NGTL) to 8 cents/Mcf (ATCO). The Board considers that the addition to the FT-A toll of an amount that is close to the midpoint between these two proposals may represent a reasonable approximation of intra-Alberta transmission costs, with this charge to be possibly further refined by reference to more detailed COS information in future.[12]

NGTL submits that the detailed COS information presented in this Application does not support such an outcome. Moreover, setting aside the inappropriateness of the 8 cents/Mcf recommended by ATCO Pipelines, such an approach would not be fair and equitable to intra-Alberta shippers without a corresponding offset to the FT-R rate. An offset to the FT-R rate could be incorporated in a manner similar to Alternatives 2 and 3

[12] EUB Decision 2004-097, page 19.

of the Alternative Methodologies COS Study, discussed in Section 2.2.2. The midpoint of ATCO Pipelines' 2004 proposal of 8 cents/Mcf and NGTL's existing FT-A transmission component of 0 cents/Mcf is 4 cents/Mcf. This amount, combined with the metering component of 1.4 cents/Mcf, results in a total FT-A rate of 5.4 cents/Mcf. In order to maintain the transmission split between the export and intra-Alberta markets, the average FT-R rate would need to be set at 10.6 cents/Mcf and the FT-D rate would need to be set at 21.2 cents/Mcf. This would lead to the same problems NGTL described for Alternative 3, but to an even greater degree. An export delivery rate of 21.2 cents/Mcf would be substantially greater than any historical FT-D rate. This could lead to border bypass, require NGTL to adjust receipt floor and ceiling levels, and/or require NGTL to implement additional LRS type services to retain load. Similarly, a direct FT-A delivery rate of this magnitude would provide greater incentive for intra-Alberta bypass or for dually connected receipt producers to choose other service providers such as ATCO Pipelines.

Q43. How does maintaining the existing rate design impact NGTL's competitive position relative to ATCO Pipelines?

A43. Continuation of the existing rate design maintains the competitive landscape that has allowed ATCO Pipelines to increase its share of receipts at the expense of NGTL and excluded NGTL from delivering to intra-Alberta markets it had historically served indirectly. These outcomes are illustrated by Figures 2.3-1 to 2.3-3.

Figure 2.3-1 shows that ATCO Pipelines has dramatically increased its producer receipts.

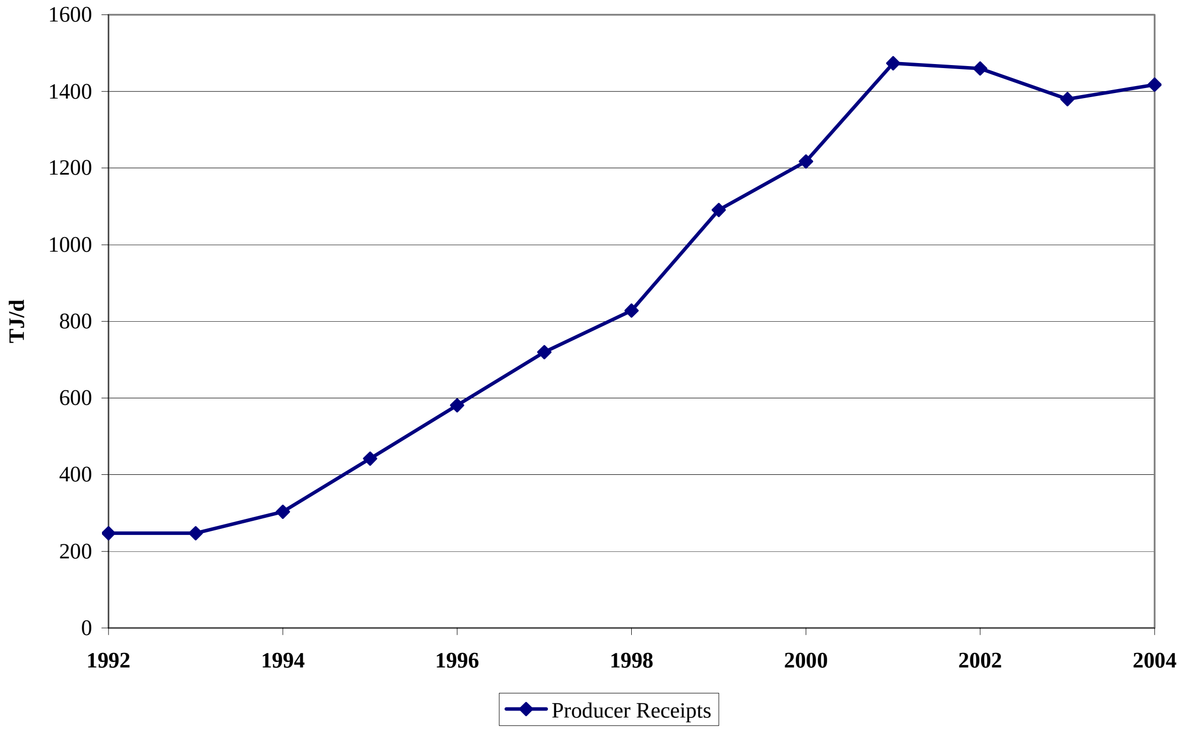
Figure 2.3-2 indicates that since 1999 significant receipt volumes at the stations dually connected to the Alberta System and the ATCO Pipelines system that originally entered the Alberta System have been offloaded to the ATCO Pipelines system.

Figure 2.3-3 shows the drop in deliveries made from the Alberta System to ATCO Pipelines during the same time frame. The decrease in deliveries to ATCO Pipelines is similar to the decrease in receipts onto the Alberta System in Figure 2.3-2.

In summary, ATCO Pipelines has offloaded receipts from the dually connected stations, reducing the deliveries historically made from the Alberta System to ATCO Pipelines, which has eliminated both the receipt and delivery revenues that NGTL previously collected on these volumes for its role in the transportation chain serving these intra-Alberta markets.

Figure 2.3-1

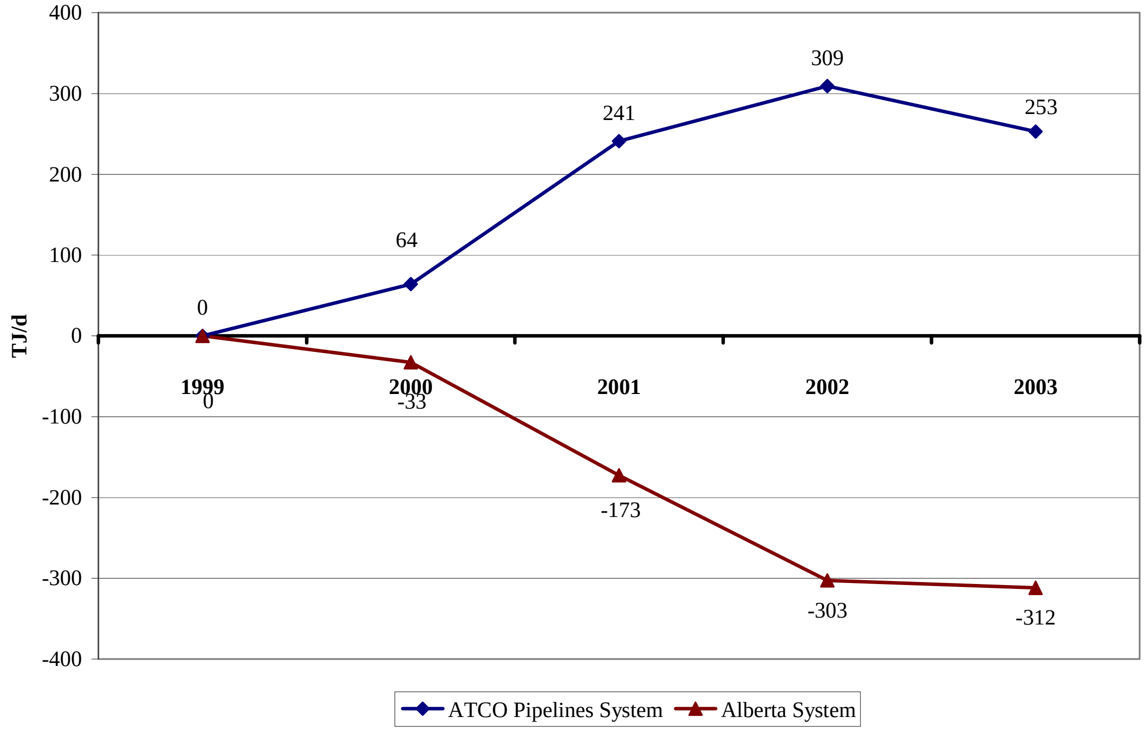
ATCO Pipelines System Receipts



Source:
NUL 1993 GRA Phase 1, Schedule 4.50 Revised; CWNG 1992 GRA Phase 1, Sections 5.3 and 5.4; CWNG 1998 GRA Phase 1, Section 7, Schedule 5.30; ATCO Website; ATCO Pipelines 2004 GRA Phase 1, Responses to Information requests AUMA-EDM-AP-7(a) and (b); and ATCO Pipelines 2004 GRA Phase 2, Exhibit 035-16. For years that throughput information was not available from the listed sources, NGTL estimated the throughput by allocating the change between known prior and later years equally amongst the years for which information was not available.

Figure 2.3-2

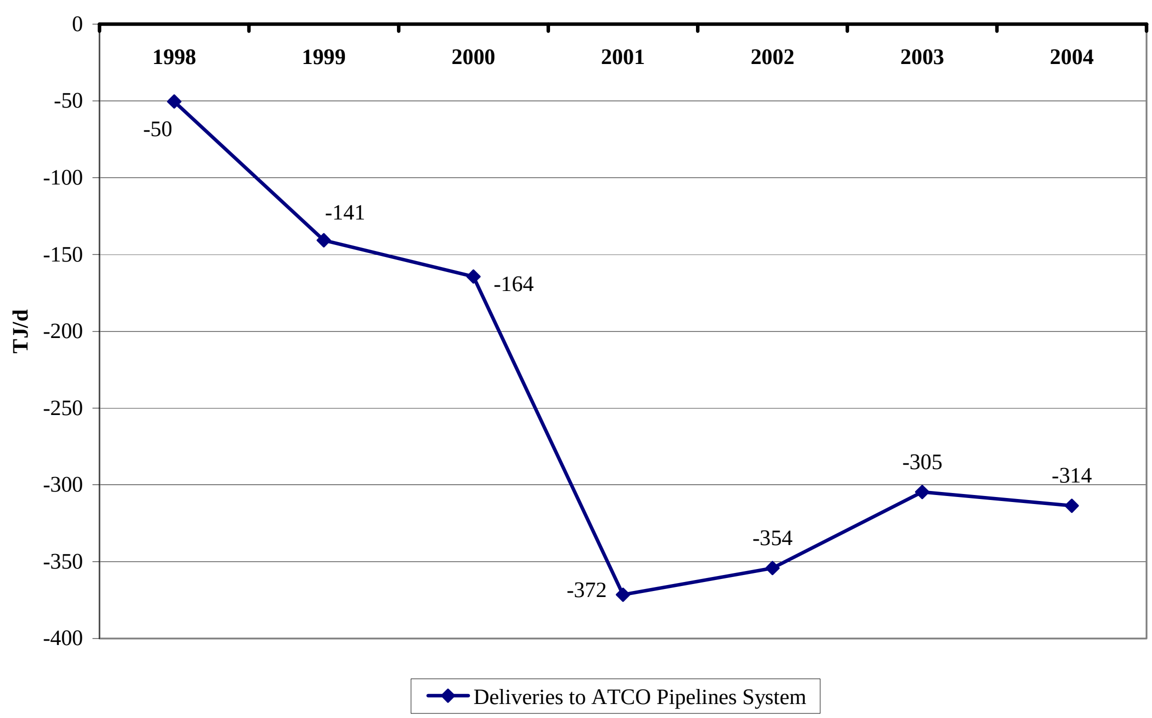
Change in Throughput at Dually Connected Stations from 1999 Levels



Source:
ATCO Pipelines 2004 GRA - Phase 1, responses to Information Requests CAL-AP-15(b) and (c). ATCO did not provide information prior to 1999.

Figure 2.3-3

Change in Deliveries from the Alberta System to ATCO Pipelines System from 1997 Levels



2.4 INTRA-ALBERTA DELIVERY SERVICE ACCOUNTABILITY

Q44. What is the purpose of the evidence in this section?

A44. In this section, NGTL discusses the existing provisions governing intra-Alberta delivery service accountability and a range of potential alternatives. NGTL provides this information in part in response to statements the Board made in Decision 2004-097. Specifically, the Board stated:

> However, the Board considers that these [accountability provisions] cannot be considered in isolation from NGTL's rate design, including the FT-A, FT-R and FT-P tariffs.
>
> …
>
> However, the Board would anticipate a possible further review of the cost accountability issue in future if the anticipated improvements in cost transparency and a more cost accountable FT-A toll are not satisfactorily addressed in the 2005 Phase II proceeding.[13]

NGTL also discusses existing intra-Alberta delivery service accountability and a number of alternatives in recognition of the relationship between tolls and contractual provisions and to provide further perspective for the Board's and other parties' consideration of the appropriateness of the overall rate design.

NGTL also presents in this section information on the costs and revenues associated with the facilities it acquired in 2004 from Simmons. Given that NGTL was not able to include these facilities in the 2004 COH Study, it provides this information as an alternative demonstration that the revenues associated with these facilities exceed the costs.

---

[13] EUB Decision 2004-097, page 24.

Q45. How is the evidence organized?

A45. NGTL has organized this sub-section as follows:

Sub-section 2.4.1: presentation and discussion of the Simmons facilities acquisition and the revenues and costs associated with these facilities.

Sub-section 2.4.2: discussion of current accountability associated with intra-Alberta delivery services; and

Sub-section 2.4.3: presentation and discussion of alternatives to the existing provisions for intra-Alberta delivery service accountability.

2.4.1 Simmons Facility Analysis

Q46. Did NGTL include the facilities it acquired from Simmons in its 2004 COH study?

A46. No. The 2004 COH Study is an historical examination using 2003 data. Because the Simmons facilities were not included as part of the Alberta System until the fourth quarter of 2004, NGTL was unable to include these facilities in the 2004 COH Study.

Q47. Has NGTL otherwise examined the direct costs and revenues of the facilities acquired from Simmons?

A47. Yes. NGTL has analyzed the direct revenues and costs associated with these facilities. The results of this analysis demonstrate that the direct incremental revenue from the Simmons facilities exceeds the cost of service of the facilities. Consequently, the acquisition benefits all Alberta System customers.

Q48. Please summarize the results of NGTL's analysis.

A48. The results of the analysis are shown in Tables 2.4.1-1 through 2.4.1-3.

Table 2.4.1-1
Analysis of Simmons Facilities
Net Book Value of Simmons Facilities and the Alberta System
($ million)

	Simmons	Alberta System	Simmons % of Alberta System
Compression	3.2	893	0.4%
Metering	0.6	345	0.2%
Pipes	16.6	3,067	0.5%
Total Pipeline Assets	**20.4**	**4,305**	**0.5%**

The net book value of the Simmons facilities are as of December 31, 2004 whereas the net book value of the Alberta System is as of December 31, 2003. The Simmons facilities represent only 0.5 percent of the Alberta System.

Table 2.4.1-2
Analysis of Simmons Facilities
Detailed Cost of Service
($ million)

	Compression	Pipe	Metering	Total Simmons
Direct Costs				
Operating Return	0.28	1.49	0.06	1.83
Depreciation	0.04	0.24	0.01	0.28
Municipal Tax	0.04	0.78	0.01	0.83
Income Tax	0.12	0.62	0.02	0.76
Total Direct Costs	**0.47**	**3.12**	**0.09**	**3.69**
Non-direct Costs				
General Operating Assets	0.01	0.06	0.00	0.07
Calgary Offices	0.01	0.04	0.00	0.05
Field/Service Centers, Vehicles	0.02	0.09	0.00	0.12
Information Technology	0.02	0.12	0.00	0.15
General plant total	**0.06**	**0.31**	**0.01**	**0.39**
Cash Working Capital	0.01	0.06	0.00	0.08
Material & Supplies Inventory	0.00	0.01	0.00	0.01
Line pack Gas	0.00	0.01	0.00	0.01
Unamortized Debt Issue Costs	0.00	0.01	0.00	0.01
Working capital total	**0.02**	**0.10**	**0.00**	**0.12**
Maintenance	0.20	0.29	0.59	1.08
Other Departments	0.04	0.22	0.01	0.28
General Expenses	0.04	0.22	0.01	0.27
Other Expenses	0.02	0.10	0.00	0.12
G&A total	**0.31**	**0.83**	**0.61**	**1.74**
Total non-direct Costs	**0.38**	**1.24**	**0.62**	**2.24**
Total Direct and Non-direct Costs	**0.86**	**4.36**	**0.72**	**5.93**

Note:
Allocated amounts less than $100,000 appear as 0.00 due to rounding.

All direct costs have been annualized based on December 2004 results. The non-direct costs have also been annualized and allocated to the Simmons assets based on their 2003 relationship to the NBV of Alberta System assets applied to the NBV of the Simmons facilities. This provides an annual estimate for the Simmons facilities.

Table 2.4.1-3
Analysis of Simmons Facilities
Revenues and Costs
($ million)

	Direct	Non-direct	Total
Cost of Service Analysis:			
Pipe	3.12	1.24	4.36
Meter Stations	0.09	0.62	0.72
Compressor Stations	0.47	0.38	0.86
TOTAL SIMMONS COSTS	**3.69**	**2.24**	**5.93**
Revenue:			
CO_2	0.02	0.00	0.02
FT-A	0.41	0.00	0.41
FT-R	2.58	0.00	2.58
IT-R	0.99	0.00	0.99
FT-P	7.62	0.00	7.62
TOTAL REVENUE:	**11.62**	**0.00**	**11.62**

Note:
1. Allocated amounts less than $100,000 show up here as 0.00 due to rounding.

The cost of service numbers are from Table 2.4.1-2. The revenue numbers have been annualized based on the actual results for the month of December 2004. They represent only the revenues that are directly associated with meter stations connected to Simmons pipe. In addition to this direct revenue there is an additional $2.7 million of indirect FT-R revenue associated with the FT-A service.

2.4.2 Current Intra-Alberta Delivery Service Accountability Provisions

Q49. What are the current accountability provisions associated with intra-Alberta delivery services?

A49. Accountability for the costs of intra-Alberta delivery services is provided through the FT-P service, the FT-A service and the FCS.

The rate for FT-P service is comprised of three components: metering gas on the system; metering gas off the system; and the transmission between the receipt meter stations and the delivery meter station. Thus, the FT-P rate directly accounts for the entire service cost.

The rate for FT-A service accounts for the metering costs to deliver gas from the Alberta System. It does not account for costs associated with metering gas on the System or for any transmission costs. The costs to meter gas on the System, as well as transmission costs associated with deliveries to intra-Alberta markets, are directly accounted for in the FT-R rate. FT-A service shippers indirectly account for these costs when they purchase the gas to be delivered by their FT-A service because the FT-R rate is one of the costs that will be recovered by the seller in the price received for the sale of gas to the FT-A shipper.

As the FT-A service has a commodity rate, its associated accountability is only effective if the service is used. As a result, the FCS was developed specifically to provide accountability for intra-Alberta delivery facilities. These are primarily metering facilities. However, some FCS contracts also include a lateral component for intra-Alberta facilities that were constructed before NGTL exited the lateral business in 2000.

Each year NGTL calculates the Annual Cost of Service (ACS), which includes Operating Costs, Maintenance Costs, Municipal Taxes, Depreciation, Income Taxes and Return on Rate Base, for each FCS contract. NGTL then calculates a MAV for each FCS contract, based on the respective ACS, to establish a threshold level that is used to determine if such metering facilities have been sufficiently utilized to recover costs. If, at the end of the year, the MAV or greater has been delivered to the intra-Alberta delivery metering facilities, then the threshold level has been met and the facilities are deemed to have been sufficiently utilized. As a result, sufficient revenue will have been generated directly through FT-A and FT-P services, and indirectly through receipt services, to recover the costs associated with the metering facilities. In this instance, the FCS Charge would be zero. If no volumes were delivered through the metering facilities, the FCS Charge would be equivalent to the ACS as no revenue would have been generated. For volumes of natural gas delivered through the metering facilities between zero and the MAV, the FCS Charge would be the portion of the ACS that was not recovered through the FT-A, FT-P or receipt services. For example, if 75% of the MAV was delivered, the FCS charge would be equivalent to 25% of the ACS.

NGTL made significant changes to the MAV in October 2003 that have resulted in a dramatic increase in FCS revenue. Table 2.4.2-1 shows the FCS-MAV revenue for the years 2002 to 2004. 2004 is the first year to include the full effect of the 2003 modifications to the MAV.

Table 2.4.2-1
FCS-MAV Revenue from 2002 to 2004

	Year		
	2002	**2003**	**2004**
FCS-MAV revenue ($000)	1,798	3,782	4,868
Revenue change from 2002 ($000)	n/a	1,984	3,070
Revenue change from 2002 (%)	n/a	110%	171%

This table shows that the 2004 MAV revenue is 171% greater than in 2002.

In October 2003, the FCS was also modified to incorporate EAV accountability for intra-Alberta delivery extensions. EAV accountability is structured similarly to MAV accountability. If a minimum annual volume is not moved through the facilities the customer holding the EAV will receive a direct charge. However, unlike the MAV, the EAV requirement is not calculated every year and is not based on the annual cost of the associated facilities. Instead, the minimum EAV is based on the volume criteria established under NGTL's Guidelines for New Facilities used to determine mainline extension facilities, and the minimum term is three years. This approach is consistent with customer commitments for mainline receipt extension facilities, where the minimum volume requirement is 100 MMcf/d and a minimum three year secondary term is required.

Q50. Has NGTL recently examined the appropriateness of these accountability provisions?

A50. Yes. NGTL provided analysis in its 2004 GRA Phase 2, Sections 2.6 and 2.7, on all meter stations and all transmission facilities not associated with the major export delivery stations. In this Application, NGTL provides an update to a subset of these facilities, comprised of intra-Alberta delivery meter stations and the transmission facilities not associated with all export points, storage points or extraction points based on the most recent information available.

Q51. Why is NGTL only providing analysis for this subset of facilities?

A51. These metering facilities are directly associated with intra-Alberta delivery services. These transmission facilities are associated with receipt and intra-Alberta delivery services as, with the exception of FT-P service, both receipt and delivery services are required to transport gas on the Alberta System. However, consistent with its approach in its 2004 GRA Phase 2, NGTL has not allocated any of the costs associated with these facilities to receipt services to demonstrate that a level of accountability greater than what is required, is provided.

Q52. What analysis was performed?

A52. NGTL considered revenues and costs directly associated with this subset of facilities, to assess whether the existing accountability ensures that revenues cover costs.

For delivery services, NGTL used the 2005 forecast of direct intra-Alberta revenues (FT-P, FT-A, FCS).

For meter stations costs, NGTL identified all intra-Alberta delivery meter stations and extracted their related costs from the first and second steps of the functionalization process of the COS Study as described in Section 2.1 of this Application.

For transmission costs, NGTL identified all pipe sections not associated with export deliveries, extraction or storage. This was accomplished by identifying the pipe upstream of the stations identified as intra-Alberta delivery that were not included in the algorithms utilized to calculate receipt point specific rates. Next, the costs related to these pipe sections were extracted from the first and second steps of the functionalization process of the 2004 COS Study as described in Section 2.1 of this Application. Thus, all direct and non-direct costs for the transmission (pipe plus compression) facilities were included.

In addition, NGTL conducted cost of service analysis for the relevant acquired Simmons facilities. These facilities were identified in the same manner as described above. However, the related costs were not contained in the 2004 COS Study as the Simmons facilities were not part of the Alberta System in 2003. As a result, NGTL performed a separate analysis to determine the costs related to the Simmons facilities. The methodology for calculating direct costs was performed as described in the 2004 COS Study but for only the month of December, 2004 and then annualized. However, all non-direct costs were allocated based on their 2003 relationship to NBV applied to the NBV of the Simmons facilities.

Q53. Please summarize the results of the analysis performed for intra-Alberta delivery services.

A53. The results of the analysis are shown in Tables 2.4.2-2 through 2.4.2-4.

Table 2.4.2-2
Delivery Facilities not Associated with Export, Storage, or Extraction
Summary of Assets and Costs
($ million)

	NBV of Assets	% of Total Assets	Total Direct and Non-Direct Costs	% of Total Asset Cost
Pipes	6.2	0.1%	2.5	0.2%
Meter Stations	44.4	0.9%	14.9	1.1%
Assets not Associated with Borders, Extraction or Storage	50.6	1.0%	17.5	1.3%
Total Assets	4,895		1,299	
Simmons Pipe not Associated with Borders, Extraction or Storage	6.1	0.1%	2.1	0.2%
Pipes Including Simmons	12.3	0.3%	4.6	0.4%
Pipes & Meter Stations including Simmons	56.8	1.2%	19.6	1.5%

The first four rows of table 2.4.2-2 are derived from NGTL's 2004 COS Study. The data show that the NBV of pipe not associated with export, storage or extraction points is approximately 0.1% of the total Alberta System NBV and the NBV of all assets not associated with export, storage and extraction points represents approximately 1.0% of the total Alberta System NBV. In terms of cost, the total direct and non-direct costs of pipe not associated with export, storage or extraction points is approximately 0.2% of the total Alberta System asset cost, and the cost of all assets not associated with export, storage and extraction points represents approximately 1.3% of the total Alberta System asset cost.

The fifth row identifies the Simmons facilities that would be included in this category had they been part of the Alberta System in 2003 (approximately 30% of the total Simmons facilities). The last two rows recalculate the value and costs of the facilities not associated with export, storage or extraction, including the value and costs of the Simmons facilities. Including the Simmons facilities, the NBV of pipe not associated with export, storage or extraction points increases to approximately 0.3% of the total Alberta System NBV and the NBV of all assets not associated with export, storage and extraction points increases to approximately 1.2% of the total Alberta System NBV. In terms of costs, including the Simmons facilities increases the total direct and non-direct costs of pipe not associated with export, storage or extraction points to approximately 0.4% of the total Alberta System cost, and the cost of all assets not associated with export, storage and extraction points is increased to approximately 1.5% of the total Alberta System cost.

Table 2.4.2-3
Delivery Facilities not Associated with Export, Storage, or Extraction
Detailed Cost of Service
($ million)

	Pipes	Meter Stations	Total Pipes & Meter Stations	*Simmons Pipe	*Total Pipes Including Simmons	*Total Pipes & Meter Stations
Direct Costs						
Operating Return	0.60	4.28	4.87	0.55	1.15	5.43
Depreciation	0.39	1.76	2.15	0.09	0.48	2.24
Municipal Tax	0.13	0.26	0.38	0.29	0.42	0.67
Income Tax	0.23	1.62	1.85	0.23	0.45	2.08
Total Direct Costs	**1.34**	**7.92**	**9.26**	**1.16**	**2.49**	**10.41**
Non-direct Costs						
General Operating Assets	0.06	0.15	0.21	0.02	0.08	0.23
Calgary Offices	0.04	0.11	0.15	0.01	0.05	0.17
Field/Service Centers, Vehicles	0.10	0.25	0.35	0.03	0.13	0.38
Information Technology	0.12	0.33	0.45	0.04	0.16	0.49
General plant total	**0.32**	**0.84**	**1.17**	**0.10**	**0.42**	**1.26**
Cash Working Capital	0.07	0.17	0.24	0.02	0.09	0.26
Material & Supplies Inventory	0.01	0.03	0.04	0.00	0.01	0.04
Linepack Gas	0.01	-	0.01	0.00	0.02	0.02
Unamortized Debt Issue Costs	0.01	0.03	0.04	0.00	0.01	0.04
Working capital total	**0.10**	**0.23**	**0.33**	**0.03**	**0.13**	**0.36**
Maintenance	0.08	4.47	4.55	0.09	0.17	4.64
Other Departments	0.23	0.60	0.83	0.07	0.30	0.90
General Expenses	0.22	0.59	0.81	0.07	0.29	0.88
Other Expenses	0.10	0.26	0.36	0.03	0.13	0.39
G&A total	**0.63**	**5.92**	**6.56**	**0.26**	**0.89**	**6.82**
Total non-direct Costs	**1.06**	**7.00**	**8.06**	**0.39**	**1.44**	**8.44**
Allocated Compression Costs	**0.14**	**-**	**0.14**	**0.56**	**0.71**	**0.71**
Total Direct & Non-direct Costs	**2.54**	**14.92**	**17.46**	**2.10**	**4.64**	**19.56**

Notes:
1. Allocated amounts less than $100,000 show up here as 0.0 due to rounding.
2. A dash ("-") means the cost item is not applicable to the function.
3. Includes only pipe not associated with borders, extraction or storage.
* Not part of the 2003 COS Study

Table 2.4.2-3 details the annual cost of service associated with these facilities. Based on 2003 information, the existing Alberta System delivery facilities not associated with export, storage, or extraction had an annual cost of service of $17.46 million. Including the annualized cost of service estimate for the Simmons facilities of $2.10 million (based on December 2004), the total cost of service increases to $19.56 million.

Table 2.4.2-4
Delivery Facilities not Associated with Export, Storage, or Extraction
Revenues and Costs
($ million)

	Direct	Non-direct	Total
Cost of Service Analysis:			
Pipe	1.34	1.20	2.54
Metering	7.92	7.00	14.92
Simmons Related Costs	1.16	0.95	2.10
TOTAL COSTS	**10.41**	**9.15**	**19.56**
2005 Forecast Revenue:			
FCS Charges	4.94	-	4.94
FT-A	5.32	-	5.32
FT-P[1]	22.09	-	22.09
TOTAL REVENUE:[2]	**32.35**	**0.00**	**32.35**

Notes:

1 FT-P service direct revenue is based on 100% of the FT-P rate which includes a component for the receipt metering costs and the delivery metering costs, each of which is $2.0 million.

2 Total Revenue does not include the indirect receipt revenue attributed to the FT-A delivery volumes of 1.03 Bcf/d multiplied by the average FT-R rate of 15.51¢/Mcf = $58.1 million.

Table 2.4.2-4 includes the costs as per Table 2.4.2-3 and adds the forecasted revenue for the services associated with these facilities. Only the direct revenue associated with these facilities has been included. In addition to the $32 million in direct revenue there is an additional $58 million in indirect receipt revenue associated with the FT-A service. The direct revenue is 65% greater than the cost of the facilities.

In summary, because the direct revenue from services associated with these facilities exceeds the cost of service of these facilities, NGTL believes that the current accountability provisions are adequate.

Q54. Are the costs associated with all of these facilities accounted for by FCS agreements?

A54. No. All of the meter station costs are accounted for under FCS agreements. However, only 85% of the NBV of the identified pipeline facilities are accounted for under an FCS-MAV agreement. The remaining 15% of the NBV is for pipe that is still being used even though it was originally constructed to connect receipt stations that have since been retired. The accountability for these facilities was satisfied by the receipt service before the receipt stations were retired.

Q55. Does this analysis of revenues and costs for delivery facilities not associated with export, storage, or extraction include any TBO costs?

A55. No. As described in 2004 COS Study, Section 3, TBO costs are directly assigned to the transmission function. As a result, all TBO costs have been allocated to pipe between the receipt and export delivery stations and costs are recovered through rates for these services. This approach is consistent with the fact that TBO agreements are used to expand or extend mainline facilities used to transport receipt gas to delivery points.

In any event, even if TBO costs were included in this analysis, revenues would still exceed costs. The estimated cost for the Ventures, ATCO and Kearl Lake TBO arrangements for 2005 is $11.55 million. If this amount were included in the analysis, the total cost for the delivery facilities not associated with export, storage and extraction would increase to $31.11 million. This amount is still less than the direct revenue of $32 million, and substantially less than the combined direct and indirect revenue of $90 million.

Q56. Are any changes required in 2005 to the existing terms governing intra-Alberta service accountability?

A56. No. These provisions were significantly modified in 2003 to increase the accountability for intra-Alberta delivery facilities. As demonstrated by NGTL's analysis, the direct revenues associated with intra-Alberta delivery services exceed the cost of service of the associated facilities.

It could be argued that some of the costs related to these transmission facilities should more appropriately be attributed to receipt services, or some of the receipt revenue should be included in this analysis. If these things were done, the excess revenue generated over the cost of service would be further increased.

However, NGTL believes that on balance, these services and their associated accountability provisions are sufficient at this time.

Q57. Has Dr. Gaske assessed the reasonableness of the existing terms governing intra-Alberta service accountability?

A57. Yes. Dr. Gaske reviews the existing terms governing intra-Alberta service accountability and concludes that they are adequate.

Q58. Is the accountability for intra-Alberta service expected to stay the same for the foreseeable future?

A58. Accountability for services, along with rate design, will continue to evolve as a function of changes in the business environment. NGTL expects to have ongoing discussion with stakeholders through its collaborative process and to bring forward changes for Board approval from time to time.

2.4.3 Alternatives to Existing Intra-Alberta Delivery Services

Q59. Has NGTL examined alternatives to the existing provisions for intra-Alberta delivery service?

A59. Yes. NGTL has examined an alternative which would involve:

- making the FT-A service a demand service, similar in concept to the FT-D and FT-R services;
- introducing a new intra-Alberta interruptible delivery service (IT-A), similar in concept to the IT-D and IT-R services; and
- replacing the MAV component of the FCS for intra-Alberta delivery stations with primary term FT-A or FT-P service contracts similar to those used for FT-R service.

NGTL has also examined some options for the EAV component of the FCS.

Q60. Why has NGTL considered these alternatives?

A60. These alternatives have been considered in recognition of the relationship between rates and contractual provisions and to provide perspective for the Board's consideration of the overall rate design.

Q61. Please provide an overview of the current FT-A service.

A61. Under the current FT-A service, gas is delivered from the Alberta System at valid Alberta delivery points. A valid Alberta delivery point is defined as a delivery point within Alberta where gas that is not to be removed from the Province is delivered, and which has an associated FCS agreement at such delivery point. FT-A service is not available for volumes of natural gas delivered for extraction or storage or to individual residences, farms or gas co-ops. The rate for FT-A service is based on the system average cost to meter gas and it is charged only on actual deliveries (i.e., it is a commodity, not a demand, rate).

Q62. Please describe the modifications to FT-A service for this alternative.

A62. Table 2.4.3-1 provides an overview of the modifications and a comparison with the current service.

Table 2.4.3-1
Comparison of Attributes of the Current and the Modified FT-A Service

Service Attribute	**Current FT-A**	**Modified FT-A**
No. of Receipt Points	One per contract	One per contract
Contract Quantity	Not defined	Defined in contract
Type of Rate	Commodity	Demand
Rate	$0.50 / 10^3m^3/d	$15.21 / 10^3m^3/month
Term Differentiated Rates	No	Yes. Same as FT-R
Monthly Charges	Commodity x Rate	Demand x Rate + over-run
Over-run Rate	n/a	IT-A Rate
Initial Term (no Facilities)	Minimum one year	Minimum one year
Initial Term (Facilities)	Minimum one year	Primary Term
Renewal Term	Minimum one year in increments of one year terminates on Gas Year	Minimum one year in increments of one month
Renewal Notice	One year	One year
Capacity Release	Not allowed	Allowed
Transfers	Not allowed	Not allowed
Term Swaps	Not allowed	Not allowed
Title Transfers	Allowed	Allowed
Assignments	n/a	All or partial volumes
Priority	Same as FT-D	Same as FT-D
Accountability	FCS - MAV	Primary Term

The main difference between the existing and modified FT-A service would be to the type of rate and the accountability provisions. The alternative would establish FT-A as a demand service which requires a specified volume and a monthly demand rate, and would determine accountability based on a primary term calculation and a demand rate instead of the FCS-MAV calculation and a commodity rate.

Q63. Does NGTL currently offer an IT-A service?

A63. No. At this time FT-A service has a commodity rate structure so there is no need to have an independent interruptible service. However, if FT-A service was a demand service, it would be reasonable to introduce a complementary interruptible service. In such a case, intra-Alberta markets would have firm (FT-A) and interruptible (IT-A) services available, similar to the existing structure for export delivery services (FT-D and IT-D) and receipt services (FT-R and IT-R).

Q64. Please describe the IT-A service that would be associated with this alternative.

A64. IT-A would be an interruptible service for intra-Alberta markets structured in a similar manner to IT-D for export markets or IT-R for receipt points. Specifically, an IT-A service might have the following attributes:

- a daily commodity rate priced at 110% of the daily equivalent FT-A rate;
- a lower priority than firm services;
- the same priority as other interruptible services;
- only available if capacity exists on existing facilities (i.e., new facilities would not be constructed for this service);
- access to title transfers;
- blanket intra-Alberta delivery point access (i.e., available at all intra-Alberta delivery points with one contract); and
- in full force and effect until terminated by customer with at least one month notice.

Q65. Please describe the change to the MAV component of FCS that would be associated with this alternative.

A65. As previously mentioned, FCS-MAV contracts are required to provide appropriate accountability for intra-Alberta delivery facilities. If the FT-A service was to be changed from a commodity rate to a demand rate, then the customer accountability currently being provided by the FCS-MAV contracts for delivery stations associated with FT-A service could be replaced with direct FT-A service accountability. Similar to receipt meter station accountability for FT-R and FT-P services, the term of the FT-A contract would be set to account for the cost of the delivery meter stations, thus eliminating the need for a separate service. Specifically, the primary term of the FT-A contract would be set such that the cumulative present value revenue (CPVR) would be equal to or greater than the cumulative present value cost of service (CPVCOS). In calculating the primary term, partial years would be rounded up to the next whole year. The primary term could vary from one to 15 years. If a 15-year primary term was insufficient for the CPVR to equal or exceed the CPVCOS, then a surcharge would be charged.

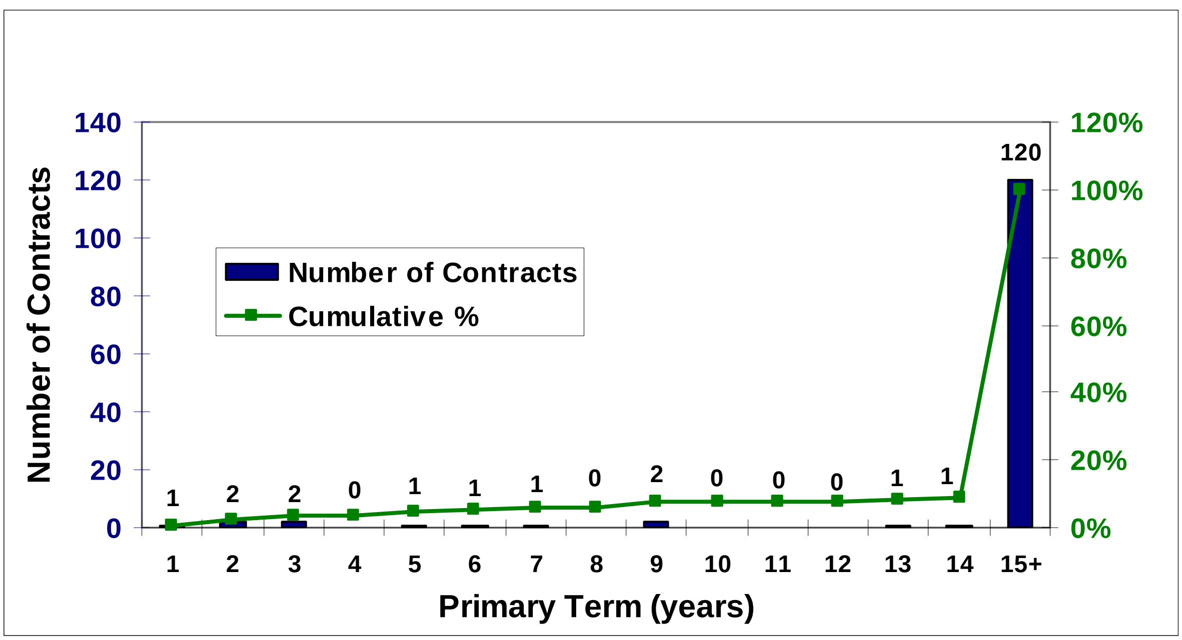
Q66. Would this modification to MAV apply to existing FCS contract holders?

A66. If the FT-A rate were to be changed to a demand rate, then NGTL suggests that existing contracts should be aligned with this modification.

Q67. Has NGTL analyzed the impact of such a modification on existing FCS holders?

A67. Yes. Figure 2.4.3-1 provides a histogram of the potential primary term for existing FCS contracts based on 2004 data.

Figure 2.4.3-1
Potential Primary Terms for Existing FCS Contracts



Based on 2004 data, the primary term would be 15 years or greater for most of the existing FCS contracts. Customers that hold contracts identified with a primary term of 15 years or more would be required to:

a) request the retirement of facilities and reimburse the NBV of the facilities including any associated retirement costs;

b) increase their contract volume to a higher level than what was transported in 2004;

c) make a cash payment to reduce the NBV of the facilities which would reduce the annual cost of service;

d) pay a surcharge to account for the shortfall in accountability not covered by the 15-year Primary Term; or

e) execute some combination of the above.

Q68. Does NGTL recommend implementation of this alternative?

A68. No. Although the alternative would provide better alignment with the accountability provisions for the suite of intra-Alberta transportation services available for export and receipt, NGTL believes that the existing accountability provisions are adequate and continue to meet the needs of industry.

Q69. Please describe the options for the EAV component of the FCS that NGTL has examined.

A69. NGTL examined the following options to the existing EAV component of the FCS:

1) basing the calculation of the EAV and the EAV component of the FCS charge on the ACS of the extension facilities, using the same methodology used to calculate the MAV and the MAV component of the FCS charge for storage facilities;

2) increasing the primary term of the FT-A contracts used to underpin all intra-Alberta delivery stations associated with the extension facilities by three years. This would cause the accountability for facilities upsteam of intra-Alberta delivery stations to be identical to the accountability for facilities downstream of receipt stations. This option would be valid only if the FT-A service rate was changed to have a demand rate;

3) increasing the primary term of the FT-A contracts used to underpin all intra-Alberta delivery stations associated with the extension facilities to a minimum of

ten years. This would cause the accountability for facilities upstream of intra-Alberta delivery stations to be identical to the accountability for facilities upstream of export delivery stations. This option would be valid only if the FT-A service rate was changed to a demand rate; or

4) requiring that FT-P contracts underpin extension facilities. The term of the FT-P contract would be set such that the CPVR would be equal to or greater than the CPVCOS. In calculating the primary term, partial years would be rounded up to the next whole year.

Q70. What is NGTL's assessment of the four options?

A70. Option 1 would base the facility accountability on the cost of the facilities. This would improve the relationship between the service charge and actual cost of service. It would also better align the accountability for intra-Alberta extensions with storage extensions.

Option 2 would add three years to the primary term commitment for new FT-A service. This is analogous to the three year secondary term required for all new receipt service. However, there would not be a direct relationship between the accountability provision and the cost of the facilities.

Option 3 would align the accountability for intra-Alberta delivery service with the existing accountability for export delivery service. However, as demonstrated in Figure 2.4.3-1, the majority of the intra-Alberta stations would already have a primary term in excess of ten years.

Option 4 would ensure that the cost of the facilities is directly accounted for by a service that would utilize such facilities. This would improve the relationship between the direct service charge and the actual cost of service. It would also align the accountability for intra-Alberta delivery extensions with the accountability for receipt meter stations. However, the intra-Alberta delivery extension accountability would be less similar to the receipt extension accountability than the current methodology. In addition, a delivery shipper would not be able to acquire supply at NIT, but would be required to purchase at individual receipt stations.

Q71. Does NGTL recommend implementing any of these options for the EAV component of the FCS?

A71. No. Options 2 and 3 are only applicable if the FT-A rate were to be changed to a demand rate and the MAV accountability was to be replaced by Primary Term accountability. As NGTL is not recommending implementing the FT-A and MAV changes, options 2 and 3 for the EAV are not realistic. Options 1 and 4 have merit as they would improve the relationship between the service charge associated with the facilities and the actual cost of the facilities. However, Option 4 could affect the buying and selling of gas in the gas commodity market.

2.5 SUMMARY AND CONCLUSIONS

Q72. Please summarize NGTL's evidence and its position on cost allocation and rate design for the Alberta System for 2005.

A72. NGTL believes it is appropriate to maintain its existing cost allocation methodology and the associated existing rate design for the Alberta System for 2005.

The NGTL rate design has evolved significantly in recent years to recognize and reflect industry and market developments and requirements. This evolution has included changes in cost allocation methodologies, such as NGTL's recent implementation of a direct metering component in all rates except those for IT-S and FT-X services. Other changes have included the implementation of receipt point specific pricing for firm receipt service, the introduction of FT-P service, an explicit toll for intra-Alberta delivery service, and the introduction of an EAV obligation for mainline extensions associated with intra-Alberta delivery service. Collectively, these recent evolutionary steps have improved cost allocation to Alberta System services and resulted in greater customer cost accountability for both existing and new intra-Alberta receipt and delivery services.

The recent evolutionary changes in NGTL's rate design have also recognized and been implemented within the unique and highly integrated nature of the Alberta System. The integration exists on physical, operational and commercial levels, and yields economies of scale that provide broad benefits to NGTL's customers. The Board has recognized these benefits and acknowledged that they should be appropriately allocated to all customers through NGTL's rate design.[14] However, the integrated nature of the Alberta System makes it impossible for NGTL to precisely determine the actual costs of providing particular services. Consequently, NGTL must aggregate the costs of facilities and utilize cost allocation methodologies to determine particular service rates.

NGTL has in this Application provided significant cost allocation and rate design information and analyses against which the Board and others can assess the merits of the existing rate design and potential changes to it. First, NGTL provided updated DOH and

---

[14] EUB Decision 2004-097, page 10.

COH studies based on the most recent data that were available. Second, NGTL provided a fully allocated COS study utilizing its existing cost allocation methodologies. Third, and perhaps most importantly, NGTL conducted a second COS study using six alternatives to the existing cost allocation methodologies.

Overall, NGTL's COS analyses demonstrate the reasonableness of the existing cost allocation methodologies and the resulting existing rate design. The design fully and appropriately allocates costs in a manner that generally reflects the integrated nature of the Alberta System, and satisfies the requirements of generally accepted rate design criteria.

NGTL acknowledges that each of the alternative allocation methodologies it evaluated has some merit. However, none of the alternatives would produce cost allocations or yield a rate design that is clearly superior to the existing design, based on all relevant factors. Adoption of any one of the alternatives would necessarily alter the relative costs of services. Several of the alternatives, if adopted, would result in significant distributional impacts on customers. Neither of these impacts is warranted at this time.

NGTL's analyses and conclusions are validated by Dr. Gaske's independent assessment.

NGTL also provided in the Application detailed analysis of the existing intra-Alberta cost accountability provisions and presented potential alternatives to them. Although certain of the alternatives have some merit, NGTL believes the existing accountability provisions continue to be adequate and will meet the overall needs of NGTL and industry for 2005.

Lastly, NGTL believes that its existing rate design and intra-Alberta accountability provisions remain acceptable to the majority of NGTL's customers and stakeholders for 2005. This rate design is the result of extensive consultation and significant collaborative efforts among NGTL's stakeholders, and consequently it represents a balance of interests based on acceptable compromises.

In conclusion, based on its analyses and for the reasons discussed in this Application, NGTL does not propose any changes for 2005 to its existing cost allocation methodology, rate design, or intra-Alberta delivery accountability provisions. NGTL believes that the existing methodologies and rate design remain appropriate and will result in 2005 final rates, tolls and charges for Alberta System services that are just and reasonable.

Q73. Does this conclude NGTL's evidence in this section?

A73. Yes.

APPENDIX 2A: COST OF SERVICE STUDY EXISTING ALLOCATION METHODOLOGIES

T

NOVA Gas Transmission Ltd.

Cost of Service Study

November 2004

Table of Contents

1. Introduction

This report documents the findings of NGTL's third Cost of Service ("COS") Study (the "2003 COS Study"). The methodologies of allocating non-direct costs have been revised to be consistent with the methodologies used by TransCanada's Mainline System and the report has been expanded to include the allocation of costs to all tariff services for the test year (2005).

1.1. Objectives

The objectives of this COS Study are:

- To provide an update to the 2002 COS Study using 2003 data, including numerical results.
- To determine the toll for FT-A Service in accordance with the methodology approved in Decision 2003-51.
- To revise the cost allocation methodologies to align with the methodologies used by TransCanada's Mainline System.
- To fully allocate all costs to NGTL's tariff services for the test year 2005.

1.2. Time period

This COS Study uses 2003 calendar year costs to determine the functionalized costs. For allocating costs to tariff services, the 2005 forecasted revenue requirement and volumes have been used.

1.3. Guiding principles

Several guiding principles were employed in the 2003 COS Study, they are as follows:

Alignment of cost allocations with TransCanada's Mainline system. For the most part, cost items that have no direct relationship to the pipeline facilities themselves have been allocated using pipeline assets' net book value (NBV) to be consistent with the cost allocation methodologies used by TransCanada's Mainline System.

Materiality of the cost items reflected in the report have been summarized to and presented at the lowest level of detail required. In breaking down the costs by account, no benefit would be achieved by going to a lower level of detail than provided here.

Practicality of approach. The data elements are presented here in a manner that reflects their materiality and relevance. This ensured that the study was done in a cost-effective manner.

2. Asset Value

The Alberta System's primary function is the transmission of gas which is a capital intensive activity. As pipeline capital is included in the company's assets the majority of the costs are related to these assets. Table 1 contains the NBV of assets as of December 31, 2003. The NBV of the pipeline assets has been used for allocating the majority of the costs to functions. The year-end value was used instead of a mid-year or 13-month weighted average based on the materiality and practicality principles stated earlier. Year-end NBV's cover all pipeline assets that were in-service during the year at the required level of detail.

Table 1 – NBV of Assets at December 31, 2003*

	$ Millon	% of Pipeline Assets	% of Total Assets
Compression (1)	893	21%	
Metering (2)	345	8%	
Pipes (3)	3,067	71%	
Pipeline assets total	**4,305**	**100%**	88%
General Operating Assets	58		
Calgary Offices	40		
Field/Service Centres, Vehicles	95		
Information Technology	126		
General plant total	**319**		7%
Cash Working Capital	186		
Material & Supplies Inventory	29		
Linepack Gas	25		
Unamortized Debt Issue Costs	32		
Working capital total	**271**		6%
Grand Total	**4,895**		**100%**

(1) There were 100 individual compressor units installed in 65 compressor stations in 2003.
(2) Total No. of Meter Stations in 2003: 1,119;
Average Volume (mmcf/d) in 2003: 22,138
(3) Total length of pipe in 2003: 14,131 miles.

*Numbers may not add up due to rounding.

3. Cost of Service (COS)

The COS for 2003 is included in Table 2. The cost accounts comprising the COS can be classified as either direct or non-direct costs. Direct costs are costs that are a function of, or can be expressed as a function of either Gas Plant In Service (GPIS) or net plant (NBV) and are therefore specific to the pipeline assets. They include depreciation, operating return[1], income and capital taxes, and municipal taxes. Transportation by Others (TBO) costs are included in direct costs because they pertain specifically to the transmission facilities. Conversely indirect costs are costs that are general in nature and cannot be specifically linked to the pipeline facilities themselves. They include the costs associated with general plant, working capital and general and administration accounts.

Table 2 – Cost of Service

	$ Million
Direct Costs	
Operating Return	411.7
Depreciation	242.5
Municipal Tax	67.6
Income Tax	155.5
TBO	76.8
Total Direct Costs	**954.1**
Non-direct Costs	
General Operating Assets	14.8
Calgary Offices	10.6
Field/Service Centers, Vehicles	24.3
Information Technology	31.7
General plant total	**81.4**
Cash Working Capital	16.9
Material & Supplies Inventory	2.6
Linepack Gas	2.2
Unamortized Debt Issue Costs	2.9
Working capital total	**24.6**
Maintenance	98.6
Other Departments	58.2
General Expenses	56.5
Other Expenses	25.2
G&A total	**238.5**
Total Non-direct Costs	**344.5**
Total Direct and Non-direct Costs	**1,298.5**

[1] Operating return is composed of return on equity and return on debt.

3.1. Pipeline asset costs – direct costs

The pipeline asset accounts are the repositories of the largest components of the rate base and related costs.

There are three pipeline asset accounts based on the major types of facilities that make up the pipeline system. **Compression** includes all compressor stations. This means not only the compressor units that are on site but also buildings, yard piping and other facilities that make up the stations. **Metering** includes all meter stations. Similarly to compression, this includes the meter runs themselves, buildings, yard piping, measurement automation and other facilities that make up the stations. **Pipes** include all pipelines that are in-service, other than compressors and meter stations yard pipes. Crossovers and control valves are also included in pipes.

Table 3 below sets out the direct cost accounts for December 31, 2003

Table 3 - Direct Cost Accounts
All figures in Million $

	Compression	Pipes	Metering	Total
Direct Costs				
Operating Return	85.9	293.1	32.7	411.7
Depreciation	71.2	157.7	13.6	242.5
Municipal Tax	4.7	60.7	2.1	67.6
Income Tax	32.6	110.7	12.3	155.5
TBO	-	76.8	-	76.8
Total Direct Costs	**194.4**	**699.0**	**60.7**	**954.1**

3.2. The non-direct cost accounts

These accounts are grouped into three major categories.

3.2.1. General Plant

The general plant ("GP") asset accounts contain all costs related to facilities that do not make up the physical pipeline system itself, e.g., field offices. The costs related to these assets are depreciation, operating return and income and capital taxes. The field offices also incur municipal taxes. The four GP accounts are as follows:

- General Operating Assets are compressor units, pipes and meter stations required for either emergency response or for regular maintenance on the system, e.g., pull-down compressors.
- Calgary Offices include the costs related to the Calgary Head Office (e.g., leasehold improvements).
- Field Offices, Service Centres and Vehicles include the costs related to the field offices, the service centres, the light-duty vehicles and the heavy equipment used in the field.
- Information Technology includes the investments in computer hardware and software.

3.2.2. Working Capital

Working capital accounts are the repositories for the funds necessary to carry out business operations. The costs related to these accounts include only operating return and income and capital taxes because these assets do not incur depreciation, municipal taxes or any of the other cost items. There are four working capital accounts. Linepack includes the cost of gas owned by the company in its own pipelines and used to maintain the line pressure required for the transmission of gas. Materials and supplies inventory includes the cost of materials purchased primarily for use in construction, operations, or maintenance of the pipeline system facilities. Cash working capital is the amount of cash needed to allow for the time lag between the payment of ongoing operating expenses and the collection of corresponding revenues. Unamortized debt issue costs are costs, incurred to issue long-term debt, which are recoverable from customers over the life of the debt.

3.2.3. General and Administration

The General and Administration (G&A) accounts are those against which general operating expenses are recorded, e.g. salaries and benefits of shared services employees. The G&A accounts are as follows:

- Maintenance contains the operating expenses for the Field Operations and Engineering Departments which are related to maintenance of the pipe, compressor station and meter station assets.
- Other departments contain the operating expenses for all other company departments. Included in this account are costs for Information Technology, which includes all operating expenses related to the development and maintenance of computer systems; Customer Service which contains all operating expenses for the functions of customer interface, gas control, operations planning and system design; and Corporate which contains NGTL's share of expenses from TransCanada's shared services (such as legal, corporate accounting, tax, government and community relations, internal audit, etc.).
- General expenses are <u>recurring</u> costs incurred in the conduct of business that are not department-specific. For example, this includes insurance, external legal fees, external audit fees, directors and corporate membership fees.
- Other expenses are <u>sporadic</u> costs incurred in the conduct of business that are not department-specific. Included in this account are uninsured losses, regulatory hearing expenses, transitional items and miscellaneous expenses.

It is important to note that a portion of the costs related to the engineering department were capitalized, due to the construction project nature of its work. Those capitalized costs are part of the rate base and therefore result in direct costs such as depreciation. The capitalized costs were not included in the G&A accounts because that would have resulted in double counting. The remainder of the engineering costs pertains to maintenance and is not capitalized. They were included in the maintenance costs.

4. Cost Allocations

Once all accounts and 2003 costs were identified, the functionalization step could proceed. Functions were identified, to which costs could be allocated and appropriate allocators were chosen.

Two major functions were identified for the Alberta System:

1. **Transmission** which consists of compression and pipes, as this is the company's primary function; and
2. **Metering**, where custody transfer, gas measurement and related transactional functions (e.g., scheduling) are performed at each point onto and off of the system.

4.1. Changes from previous studies

In previous COS studies different methodologies were employed for general plant, working capital accounts and G&A. In this Study, to be more consistent with the cost allocations used by TransCanada's Mainline System, the NBV of the pipeline assets has been used as the main allocator for all but two of the non-direct cost categories in the functionalization step.

In addition, this Study has been expanded to include the complete allocation to all tariff services. Functionalized costs have been allocated first to markets, based on a Distance of Haul (DOH) allocation and then to rate classes based on the cost relationships developed in the functionalization step, the forecasted revenue requirement and the forecasted volumes for the individual rate classes.

4.2. Functionalization

There are two major steps in the functionalization process:

- Assignment of pipeline asset costs to the metering and transmission functions. As transmission consists of compression and pipe, costs were first assigned to these components and then summed together for the transmission function.
- Allocation of G&A costs and other non-direct costs to the metering and transmission functions.

4.2.1. Assignment of pipeline asset costs

- Direct "assignment" is the accurate term to use here rather than allocation, because the data was collected against the specific facilities that provide those functions (or the entire pool of facilities in a function, in the case of TBO costs). Therefore the relationship is a direct one instead of being based on a formula.

4.2.2. Allocation of non-direct costs to major functions

The non-direct costs were allocated to the metering and transmission functions as follows.

General plant costs:

- General Operating Assets costs were allocated by NBV[2].
- Calgary Offices costs were allocated by NBV[2].
- Field Offices, Service Centres and Vehicles costs were allocated by NBV[2].
- Information technology asset account costs were allocated by NBV[2].

The working capital account costs:

- Linepack was allocated to transmission.
- Materials and supplies inventory costs were allocated by NBV[2].
- Cash working capital and unamortized debt issue costs were allocated by NBV[2].

G&A costs:

- Maintenance costs were allocated to the pipeline asset accounts by the historical average maintenance splits as set out below:
  - 50% to compression
  - 35% to metering
  - 15% to pipes
- Other departments costs, which include Information Technology, Customer Service, Corporate, etc., were allocated by NBV[2].

[2] Allocation by NBV refers to the net book value of each specific pipeline asset in relation to the NBV of all pipeline assets. The NBV percentages of each pipeline asset to total pipeline assets are listed on Table 1.

- General Expenses and Other expenses were allocated by NBV[2].

Table 4 below sets out the functionalized costs as of December 31, 2003.

Table 4 – Functionalized Pipeline Asset Costs
All figures in Million $

	Compression	Pipes	Transmission	Metering	Total
Direct Costs					
Operating Return	85.9	293.1	379.0	32.7	411.7
Depreciation	71.2	157.7	228.9	13.6	242.5
Municipal Tax	4.7	60.7	65.5	2.1	67.6
Income Tax	32.6	110.7	143.2	12.3	155.5
TBO	-	76.8	76.8	-	76.8
Total Direct Costs	**194.4**	**699.0**	**893.4**	**60.7**	**954.1**
Non-direct Costs					
General Operating Assets	3.1	10.5	13.6	1.2	14.8
Calgary Offices	2.2	7.6	9.8	0.9	10.6
Field/Service Centers, Vehicles	5.0	17.3	22.4	1.9	24.3
Information Technology	6.6	22.6	29.1	2.5	31.7
General plant total	**16.9**	**58.0**	**74.9**	**6.5**	**81.4**
Cash Working Capital	3.5	12.0	15.5	1.4	16.9
Material & Supplies Inventory	0.5	1.9	2.4	0.2	2.6
Linepack Gas	-	2.2	2.2	-	2.2
Unamortized Debt Issue Costs	0.6	2.0	2.6	0.2	2.9
Working capital total	**4.6**	**18.1**	**22.8**	**1.8**	**24.6**
Maintenance	49.3	14.8	64.1	34.5	98.6
Other Departments	12.1	41.5	53.5	4.7	58.2
General Expenses	11.7	40.3	52.0	4.5	56.5
Other Expenses	5.2	17.9	23.2	2.0	25.2
G&A total	**78.3**	**114.5**	**192.8**	**45.7**	**238.5**
Total non-direct Costs	**99.8**	**190.6**	**290.4**	**54.0**	**344.5**
			-		
Total Direct and Non-direct Costs	**294.2**	**889.6**	**1,183.8**	**114.7**	**1,298.5**

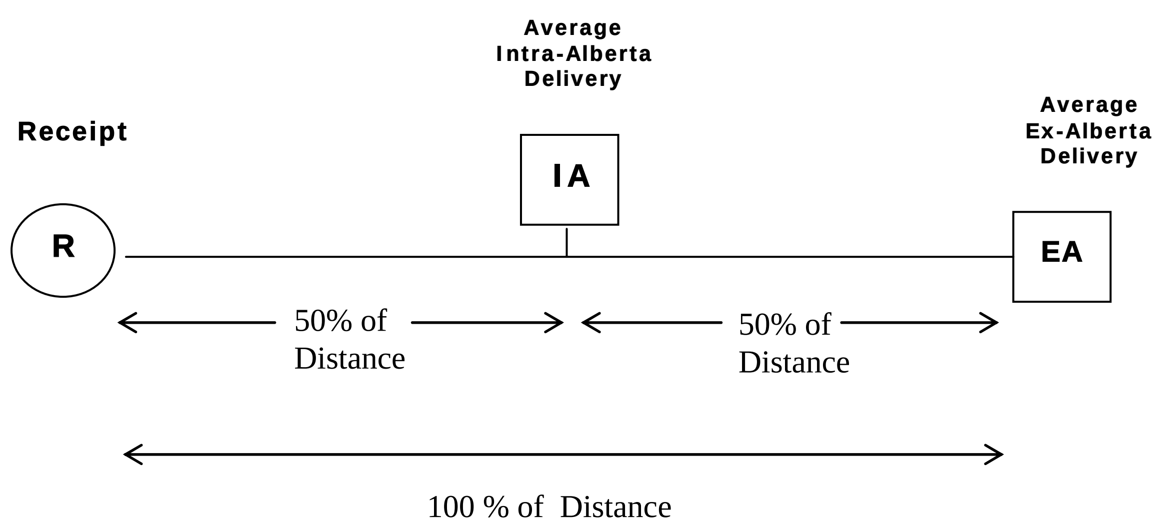
Allocated amounts less than $100,000 show up here as 0.0 due to rounding.
A dash ("-") means the cost item is not applicable to the function.

5. Allocation of Transmission Costs to Markets

Once the functionalization step was complete, it was possible to take the costs allocated to the transmission function and allocate such costs to the two main markets served by the Alberta system, the intra-Alberta market and the ex-Alberta market. The costs were allocated to these markets based on the 2003 DOH Study results (see Appendix 1). The results of the 2003 DOH Study support that on average, volumes of gas transported to intra-Alberta markets travel approximately half the distance that volumes of gas transported to ex-Alberta markets travel. The unit cost of transmission for ex-Alberta markets is therefore twice the unit cost of transmission for intra-Alberta markets. This relationship is illustrated in Diagram 1 below.

Diagram 1

Illustration of Allocation of Transmission Costs Between Intra & Ex-Alberta Markets



6. Allocation of Costs to Major Rate Classes

6.1. Transmission allocation to major rate classes (FT-R, FT-D)

The transmission costs are allocated to the major rate classes associated with the intra-Alberta and ex-Alberta markets. For the intra-Alberta market, the transmission costs are recovered by the FT-R rate and for the ex-Alberta market they are recovered by the FT-R and FT-D rates. Thus the unit cost of transmission for ex-Alberta markets is twice that of intra-Alberta markets.

6.2. *Metering allocated to major rate classes (FT-R, FT-D, FT-A)*

Metering is a common function required for all services. Therefore metering costs have been allocated to all services based on the average cost of metering as set out in the calculation below:

$$P = C \div (V * D)$$

Where

P is the unit cost in dollars per Mcf

C is the total of all costs assigned or allocated to the metering service. This total is the last figure in the second rightmost column of table 4, except that it is expressed in dollars instead of millions of dollars.

V is the average commodity volume at all meter stations on the Alberta system, as shown at the bottom of table 1 except that it is expressed in Mcf/day instead of MMcf/day.

D is the number of days in the year. This converts the average volume ("V") to the total commodity volume for the year.

For 2003, the unit cost per Mcf for the metering service was as follows:

P = \$114,741,982 ÷ (22,137,781 Mcf/day * 365 days)

Therefore, P = \$0.0142 / Mcf

6.3. *Total allocation to major rate classes (FT-R, FT-A, FT-D)*

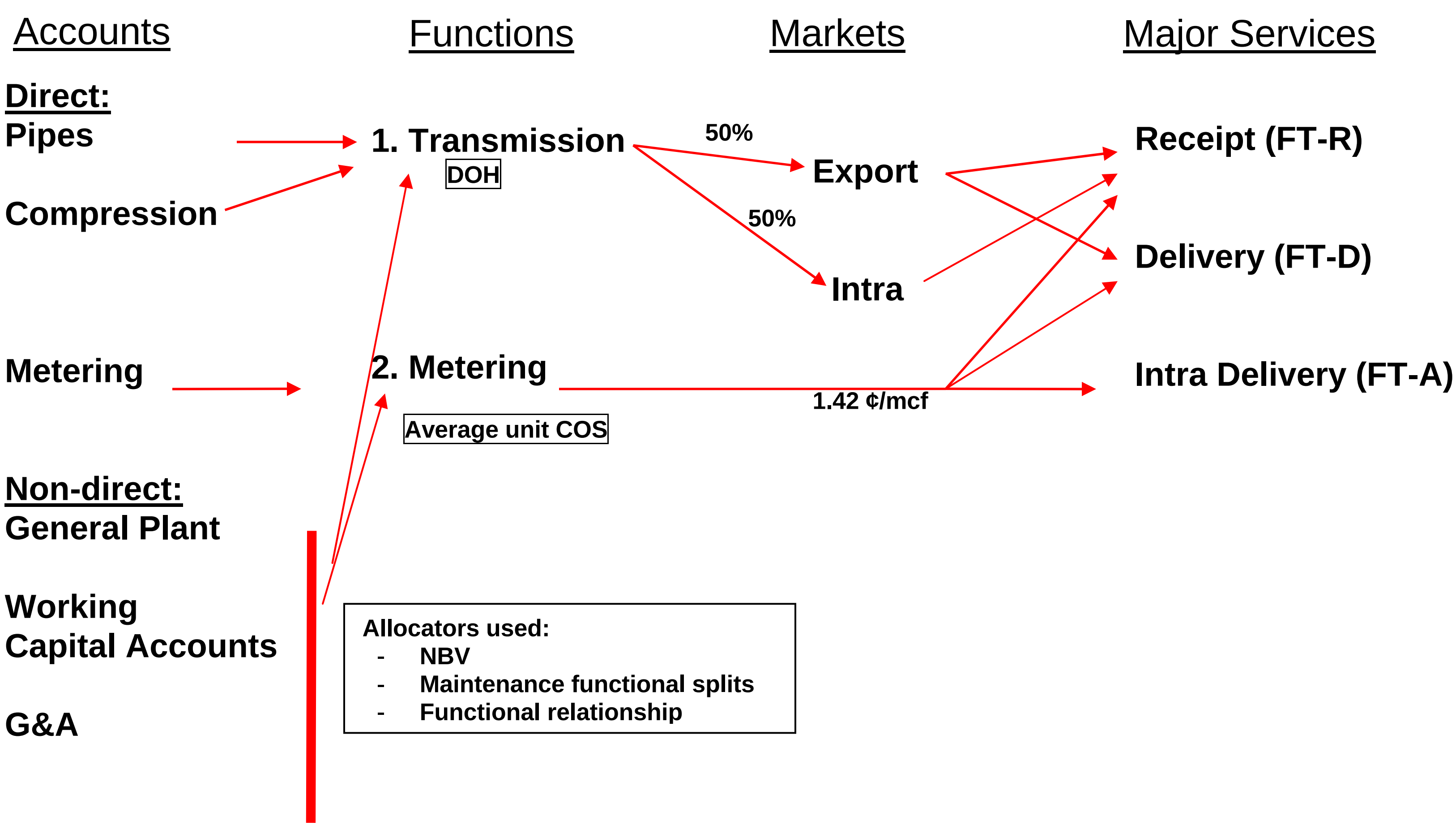
Transmission and metering costs have therefore been allocated to the major rate classes in the intra-Alberta and ex-Alberta markets in the following manner:

- Intra-Alberta (FT-R & FT-A)
- Ex-Alberta (FT-R & FT-D)

Diagram 2 shows a pictorial representation of this allocation.

Diagram 2

Application of Cost Allocations to Rates Determination



7. Allocation of Revenue Requirement to all Tariff Services

Now that the costs have been identified, the next step is to allocate the 2005 forecasted revenue requirement to all tariff services using the relationships established in the previous sections and forecasted revenue requirement and volumes for 2005. In order to have benefits that result from the integrated nature of the Alberta System distributed to other rate classes (FT-P, FT-RN, IT-R, STFT, FT-DW, IT-D) as well as to provide appropriate price signals, costs are allocated to these rate classes based on their relationship to the major rate classes, FT-D and FT-R. Diagram 3 details the allocation of the test year revenue requirement and forecasted volumes to all the tariff services. The different steps in the allocation of forecasted revenue requirement to tariff services have been identified as boxes on Diagram 3. In order to gain a fuller understanding of how the allocation takes place, the process identified in each box in Diagram 3 is explained below. Diagram 4 is a pictorial illustration that ensures the relationships of the services to one another have been maintained. Table 5 provides the forecasted costs and rates for all services.

7.1. Test year revenue requirement

Box 1 outlines the test year revenue requirement, which is to be allocated to all tariff services.

7.2. Other service revenue

Box 2 represents revenue collected from services other than FT-R and FT-D. Facilities Connection Service (FCS), OS and PTS revenues are calculated based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2 and LRS-3 services are calculated based on EUB approved rates and forecasted volumes. Revenue from FT-A service is calculated based on a forecasted volume for this service and the system average metering charge as determined in Section 6.2 of this COS Study.

Revenues from FT-P service are based on the different distance bands which apply for each FT-P contract and the forecasted volumes for each contract. The rates for the distance bands are a function of the average FT-R rate. Revenues from FT-RN and IT-R services are based on premiums to the FT-R rate and forecasted volumes for each of these services. Revenues from STFT, FT-DW, and IT-D are based on premiums to the FT-D rate and the forecasted volumes for each of these services. Therefore the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D.

7.3. Allocation of firm transportation revenue requirement

Box 3, the firm transportation revenue requirement is the revenue remaining to be collected from FT-R and FT-D services once all other transportation revenue has been subtracted from the total revenue requirement. The firm transportation revenue requirement is then divided by the sum of receipt and delivery contract demand quantities (Box 4). This calculation yields the firm transportation price (Box 5). The firm transportation price is both the FT-D price and the average FT-R price. This price consists of a metering component and a transmission component, which are equal for both services.

The firm transportation revenue requirement is then allocated to FT-R and FT-D services by multiplying the firm transportation price by the respective receipt and delivery contract demands, as show in Box 6 (a&b).

The firm receipt revenue requirement (Box 7a) is then allocated to all the individual receipt points based on the distance-diameter algorithm to calculate individual receipt specific prices (Box 8).

Diagram 3

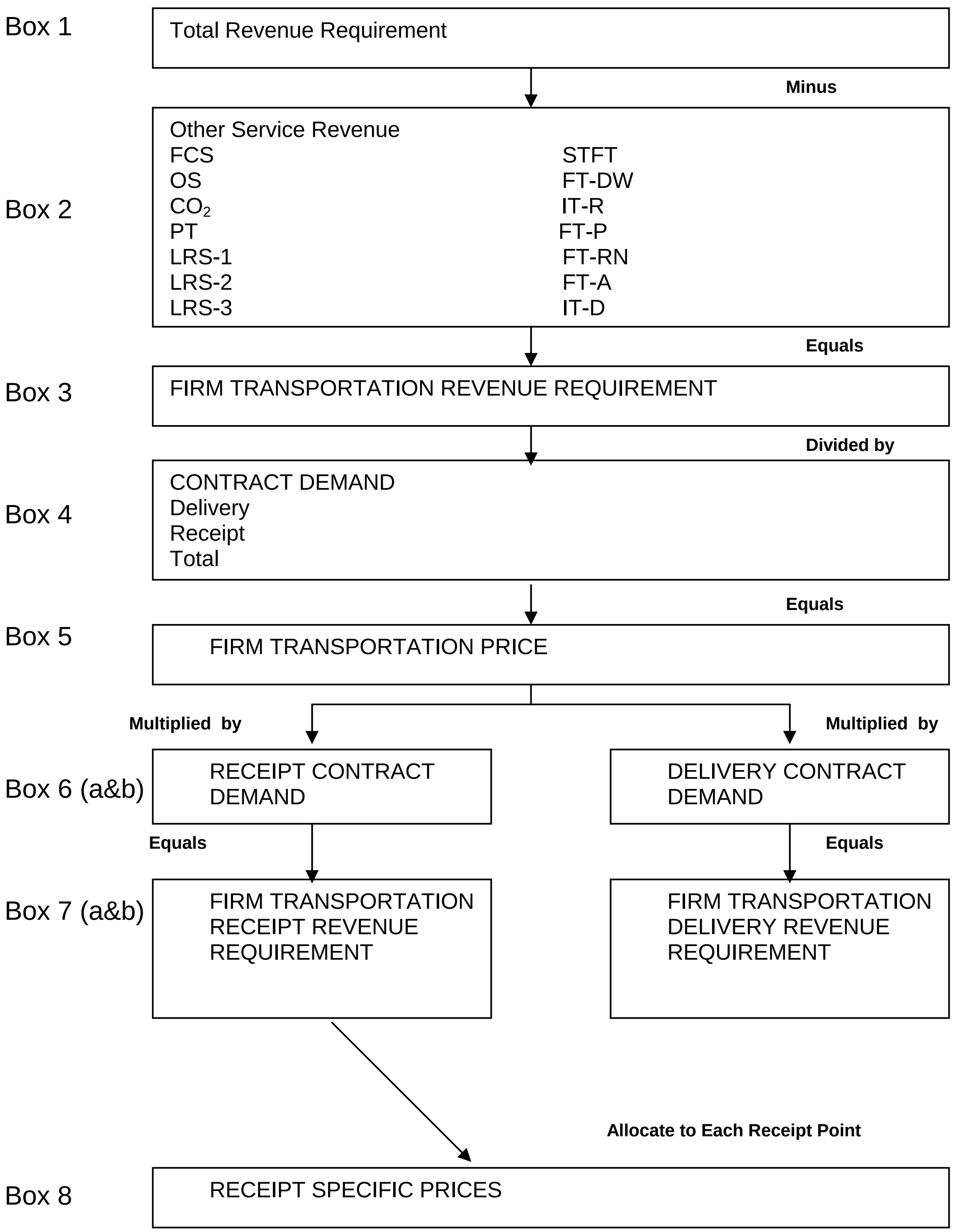
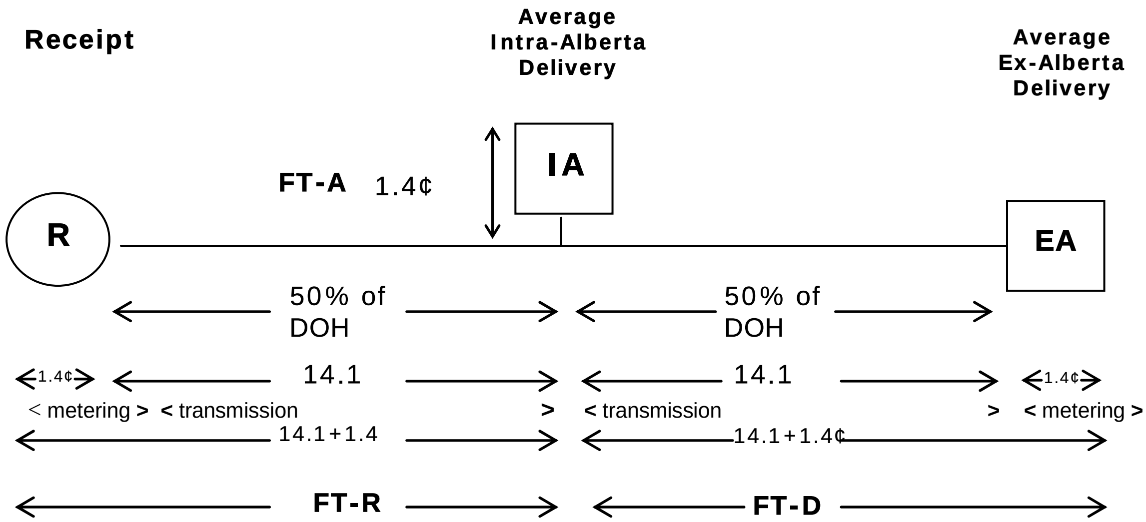

Box 1
Total Revenue Requirement
Minus
Box 2
Other Service Revenue
FCS
OS
CO_2
PT
LRS-1
LRS-2
LRS-3
STFT
FT-DW
IT-R
FT-P
FT-RN
FT-A
IT-D
Equals
Box 3
FIRM TRANSPORTATION REVENUE REQUIREMENT
Divided by
Box 4
CONTRACT DEMAND
Delivery
Receipt
Total
Equals
Box 5
FIRM TRANSPORTATION PRICE
Multiplied by
Multiplied by
Box 6 (a&b)
RECEIPT CONTRACT DEMAND
DELIVERY CONTRACT DEMAND
Equals
Equals
Box 7 (a&b)
FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT
FIRM TRANSPORTATION DELIVERY REVENUE REQUIREMENT
Allocate to Each Receipt Point
Box 8
RECEIPT SPECIFIC PRICES

Diagram 4
Illustration of Allocation of Transmission and Total Costs to Major Markets and Rate Classes Within the Markets



Transmission cost for intra-Alberta (IA) = 14.1

Transmission cost for ex-Alberta (EA) = 14.1 + 14.1 = 28.2

Ratio intra-Alberta/ex-Alberta Transmission = 14.1 ÷ 28.2 or 1:2

Total cost for intra-Alberta (IA) = FT-R + FT-A = (14.1 + 1.4) + 1.4 = 16.9

Total cost for ex-Alberta (EA) = FT-R + FT-D = (14.1 +1.4) + (14.1 + 1.4) = 31.0

Table 5

Allocation of 2005 Revenue Requirement to Services

Service	Revenue ($Millions)	Forecast Volume (10^6m^3)	Rates ($/$10^3m^3$)
FT-R[1]	452.8	82,271	167.52
FT-D	416.4	75,640	167.52
FT-A	5.3	10,557	0.50
FT-RN[2]	5.2	696	229.31
FT-P[2]	22.1	3,916	171.70
LRS[2]	43.3	6,733	195.87
LRS-2[3]	0.7	381	50,000/month
LRS-3[3]	3.3	515	192.37
STFT[2]	0.0	-	-
FT-DW[2]	0.0	-	-
IT-R[2]	123.6	21,306	5.80
IT-D[5]	64.8	10,715	6.05
FCS	4.9	n/a	n/a
CO_2[2]	15.4	n/a	n/a
PT[4]	0.9	n/a	n/a
Other Service	1.1	n/a	n/a
Total	**1,160.0**		

Notes:

1 Rate quoted is a volume weighted average for a three year contract term
2 Rate quoted is volume weighted average
3 Revenue quoted includes NGTL shareholder contribution
4 New service only forecasted in 2005.
5 Forecast quantity is net of Alternate Access

8. Appendix 1: Distance of Haul Study – 2003 Calendar Year

TransCanada

NOVA Gas Transmission Ltd.

Distance of Haul Study
Revised Methodology
2003 Calendar Year

November 2004

TABLE OF CONTENTS

TABLES

1. SUMMARY

The purpose of this distance of haul study ("DOH Study") is to determine average distances of haul for transportation of gas on the Alberta System during a particular calendar year. This Study is for the 2003 calendar year.

The results for 2003 indicate that the average distance of haul for:

- intra-Alberta deliveries was 239 km;
- ex-Alberta deliveries was 559 km; and
- all deliveries (intra-Alberta and ex-Alberta) was 517 km.

The average intra-Alberta DOH is 42.8% of the average DOH for ex-Alberta deliveries.

2. METHODOLOGY

For each month, a hydraulic simulation is performed to balance the gas received at each receipt point against the volume of gas delivered to each delivery point on the Alberta System. The flows are balanced based on the operating parameters and conditions employed on the Alberta System during that month. From this, the flow path from each receipt meter station to its associated downstream delivery stations can be determined. By reversing direction, the flow path to each delivery station can also be determined. Based on this hydraulic simulation, the distances of haul are calculated using the following steps:

1) The flow of gas is tracked in the reverse direction of the actual flow through all pipes from each delivery station to all upstream receipt stations that contribute flows to the delivery station. For each pipe in the system the following information is recorded:
   - the length of this pipe; and
   - the percent of volume at each downstream delivery station that was transported through this pipe. This is called the delivery station flow fraction. Each pipe gets a delivery station flow fraction for each downstream delivery station whose path it is in.

2) The distance of haul of a delivery station for the month is calculated by summing, for all pipes that have a delivery station flow fraction for that delivery station, the product of:
   - the length of the pipe; and
   - the delivery station flow fraction.

   The monthly DOH for the delivery station is recorded. This process is repeated for every delivery station for all 12 months.

3) The overall annual average DOH for a delivery station is determined by:
   - summing the product of the monthly DOH and actual delivered volume (the "Volume-Distance") over all 12 months and
   - dividing this sum by the actual delivery station volume for the year.

   This process is repeated for each delivery station.

4) The average distance of haul for intra-Alberta deliveries, ex-Alberta deliveries and total deliveries is calculated by:
   - summing the product of the overall annual DOH and total yearly volume for all stations in each group and
   - dividing this sum by the actual total volume for the year for all stations in each group.

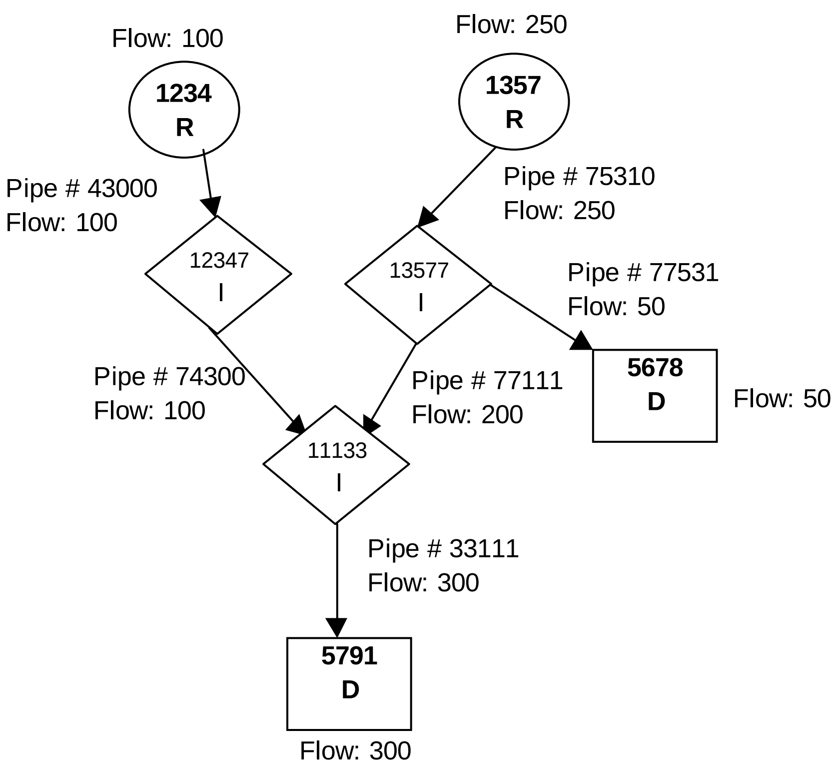
3. ILLUSTRATIVE EXAMPLE

The following is a detailed illustrative example of calculating the distance of haul for delivery stations in a simplified network. The actual delivery stations on the Alberta System have much more complex paths. Nevertheless, their DOH is calculated in exactly the same way as described in this simplified example.

In this example the network is composed of two receipt meter stations (R) and two delivery stations (D). There are 6 pieces of pipe and three intermediate nodes (I) that join different pipes together. All stations, intermediate nodes and pipes have their unique identification number. Two of those intermediate nodes are junctions. For this example, assume that the following flows in 10^3m^3 occurred at those stations for the month of January:

Meter station number	Meter station type	Meter station flow in January
1234	R	100
1357	R	250
5678	D	50
5791	D	300

From the hydraulic simulation based on the above actual flows at the meter stations, the following schematic could be derived.



At this stage of the methodology the recording spreadsheet would look like Table #1.

Table #1

Pipe #	January flow
43000	100
74300	100
75310	250
77531	50
77111	200
33111	300

In Step 1 of the methodology, the length of each pipe and the delivery flow fractions for each delivery meter station at each pipe would be recorded. The flow fraction for a particular delivery station at a particular pipe is calculated as follows:

- Flow fraction = Sum of delivery station flow fraction on links leaving downstream node * flow on current link / sum of flows on all links entering downstream node.

For example, the delivery flow fraction for pipe 33111 for station 5791 is 1.0000 (or 100% of the flow) as it is the first pipe or link. The delivery flow fraction for pipe 77111 for station 5791 is 1.0000*(200/(200+100) = 0.6667 and the delivery flow fraction for pipe 75310 for station 5791 is 0.6667*(250/250) = 0.6667; that means that 67% of the volume for station 5791 flows through pipe 77111 and 75310 (the other 33% of the volume would come from a different path – pipes 43000 and 74300). At the end of Step 1 the recording spreadsheet for this example would look like Table #2.

Table #2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(4)*(5)/(7)
Delivery Station	**Pipe #**	**D/S Node**	**Flow Fraction on Links Leaving D/S Node**	**Flow on Current Link**	**Links Entering D/S Node**	**Flows from Links Entering D/S Node**	**Flow Fraction**
5791	33111	5791	1.0000	300	33111	300	1.0000
	77111	11133	1.0000	200	77111,74300	300	0.6667
	74300	11133	1.0000	100	77111,74300	300	0.3333
	43000	12347	0.3333	100	43000	100	0.3333
	77531	5678	0.0000	50	77531	50	0.0000
	75310	13577	0.6667	250	75310	250	0.6667
5678	33111	5791	0.0000	300	33111	300	0.0000
	77111	11133	0.0000	200	77111,74300	300	0.0000
	74300	11133	0.0000	100	77111,74300	300	0.0000
	43000	12347	0.0000	100	43000	100	0.0000
	77531	5678	1.0000	50	77531	50	1.0000
	75310	13577	1.0000	250	75310	250	1.0000

All the information required to calculate the DOH for each delivery station for the illustrative month of January is now available. After Step #2 of the methodology for the month of January, the recording spreadsheet would look like Table #3.

Table #3

(1)	(2)	(3)	(4)	(5)	(6)=(3)*(4)	(7)=(3)*(5)
Pipe #	**January flow**	**Length in km**	**Delivery 5678 flow fractions**	**Delivery 5791 flow fractions**	**DOH for 5678 in km**	**DOH for 5791 in km**
43000	100	2	0.0000	0.3333	-	0.7
74300	100	5	0.0000	0.3333	-	1.7
75310	250	10	1.0000	0.6667	10.0	6.7
77531	50	3	1.0000	0.0000	3.0	-
77111	200	15	0.0000	0.6667	-	10.0
33111	300	5	0.0000	1.0000	-	5.0
				Total DOH	**13.0**	**24.0**

The DOH calculations for the remaining months (February to December) would be done exactly the same way as demonstrated above. For this example assume that at the end of the year, the monthly results have been obtained for station 5791 as shown in columns 2 to 4 and station 5678 as shown in columns 5 to 7 of Table #4. By following Step 3, the overall volume weighted average annual DOH for each delivery station can be derived as shown at the bottom of Table #4. It should be noted that the DOH for meter station 5678, is not volume dependent so will always be 13 km as only gas from receipt meter station 1357 via pipe 75310 (10 km) and pipe 77531 (3 km) is physically available. The DOH for station 5791 is volume dependant and does change from month to month as flow fractions for pipe in the station's path change.

Table #4

(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)=(5)*(6)
	Meter station 5791			**Meter station 5678**		
	DOH (km)	**Volume (10^3m^3)**	**Volume-Distance (10^3m^3 * km)**	**DOH (km)**	**Volume (10^3m^3)**	**Volume-Distance (10^3m^3 * km)**
Jan	24.0	300	7,200	13.0	50	650
Feb	23.0	350	8,050	13.0	75	975
Mar	24.1	400	9,640	13.0	75	975
Apr	20.0	350	7,000	13.0	50	650
May	22.5	300	6,750	13.0	50	650
Jun	22.5	300	6,750	13.0	50	650
Jul	23.0	320	7,360	-	-	-
Aug	24.0	340	8,160	13.0	50	650
Sep	24.2	350	8,470	13.0	50	650
Oct	22.7	300	6,810	13.0	50	650
Nov	21.3	310	6,603	13.0	50	650
Dec	22.4	310	6,944	13.0	50	650
Total		3,930	89,737		600	7,800
Annual Average	**22.8**			**13.0**		

In accordance with Step 4, the volume-weighted average annual distance of haul for all delivery stations, which in this example is two delivery stations, would be calculated as follows:

(22.8 * 3,930 + 13 * 600) / (3,930 + 600) = 21.5 km

4. RESULTS

Table 4.1 contains the DOH results for 2003. The average distance of haul for:

- intra-Alberta deliveries was 239 km; and
- ex-Alberta deliveries was 559 km.

For 2003, the average distance of haul for intra-Alberta deliveries is 42.8% of the average distance of haul for ex-Alberta deliveries.

Table 4.2 compares the annual results for 2003, using the methodology described in this report, against the results of studies from previous years. The results for 2003 do not vary significantly from previous years.

TABLE 4.1
DOH RESULTS FOR 2003

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	2003
Aver. Intra-Alberta distance (km)	226	226	230	243	252	269	257	247	250	245	231	222	239
Aver. Ex-Alberta distance (km)	517	529	557	588	595	608	574	564	573	560	546	518	559
Aver. Ex-Alberta to Intra-Alberta Ratio	2.28:1	2.34:1	2.42:1	2.42:1	2.36:1	2.26:1	2.23:1	2.29:1	2.29:1	2.28:1	2.36:1	2.33:1	2.34:1
Aver. Intra-Albert to ex-Alberta Ratio	43.8 %	42.7 %	41.4 %	41.4 %	42.4 %	44.3 %	44.7 %	43.7 %	43.6 %	43.8 %	42.4 %	42.9 %	42.8 %

TABLE 4.2
RESULTS FROM 1988 to 2003

	2003	2002	2001	2000	1999	1998	1997	1996
Aver. Intra-Alberta distance (km)	239.17	255.80	266.18	267.56	265.49	253.32	245.78	247.00
Aver. ex-Alberta distance (km)	559.42	569.38	564.03	548.68	554.91	547.88	541.83	531.68
Aver. Ex-Alberta to intra-Alberta Ratio	2.34:1	2.23:1	2.12:1	2.05:1	2.09:1	2.16:1	2.20:1	2.15:1
Aver. Intra-Alberta to ex-Alberta % Ratio	42.75%	44.93%	47.19%	48.76%	47.84%	46.24%	45.36%	46.46%

	1995	1994	1993	1992	1991	1990	1989	1988
Aver. Intra-Alberta distance (km)	249.54	234.03	229.68	219.86	224.13	224.94	198.80	209.46
Aver. ex-Alberta distance (km)	553.61	540.77	532.74	517.58	496.19	477.48	445.47	442.10
Aver. Ex-Alberta to intra-Alberta Ratio	2.22:1	2.31:1	2.32:1	2.35:1	2.21:1	2.12:1	2.24:1	2.11:1
Aver. Intra-Alberta to ex-Alberta % Ratio	45.07%	43.28%	43.11%	42.48%	45.17%	47.11%	44.63%	47.38 %

NOTES:

- The years 2002 and 2003 are calculated using the methodology approved by the EUB in Decision 2004-097, whereas all other years are calculated using the previous methodology.
- All studies are based on the calendar year except 1988 which is based on volumetric data collected over a 12-month period ending September 30, 1988.

5. DOH FOR EACH DELIVERY STATION

DOH for Ex-Alberta Deliveries:

Unit Number	Unit Name	Annual Volume (e3m3)	DOH (Km)	Volume-Distance
1250	UNITY BORDER	49,767	33.5	1,667,060
1417	COLD LAKE BDR	71,517	30.2	2,157,891
1958	EMPRESS BORDER	52,742,832	555.0	29,272,775,934
2001	ABC SALES #1	9,467,269	483.3	4,575,464,023
2002	ALBERTA-MONTANA	32,792	120.9	3,966,126
2004	ABC SALES #2	9,483,104	482.3	4,573,805,692
3886	GORDONDALE BDR	2,722	25.9	70,495
6404	MCNEILL BORDER	21,851,648	645.3	14,101,809,917
8002	ESTHER DELIVERY	67,107	9.9	665,699
8003	MERIDIAN LK DLV	139,318	0.3	43,885
	Subtotal for ex-Alberta deliveries	**93,908,075**	**559.4**	**52,532,426,722**

DOH for Intra-Alberta Deliveries:

Unit Number	Unit Name	Annual Volume (e3m3)	DOH (Km)	Volume-Distance
2360	COCHRANE EXTRCT	1,177,924	361.5	425,815,572
3050	SARATOGA SALES	4,698	408.3	1,918,431
3051	SIMONETTE SALES	7,215	0.1	500
3052	COLEMAN SALES	4,039	466.9	1,885,777
3053	SUNDRE SALES	4,990	224.5	1,120,369
3055	GRANDE PRAIR SL	0	0.0	0
3058	LUNDBRECK-COWLE	1,121	111.4	124,871
3059	ALLISON CRK SLS	8,672	464.7	4,030,424
3060	CARROT CREEK SL	12,777	223.6	2,856,401
3061	PEMBINA SALES	27,481	164.9	4,532,304
3062	E. CALGARY B SL	120,161	0.3	39,533
3063	VIRGINIA HLS SL	2,289	49.8	113,904
3065	RAT CREEK SALES	0	0.0	0
3067	BIGSTONE SALES	4,642	21.4	99,308
3068	BEAVER HILL SLS	36	34.7	1,248
3069	WILSON CRK S SL	4,783	6.0	28,640
3071	CYNTHIA SALES	0	0.0	0
3072	PADDY CREEK SLS	44,632	10.2	454,597
3073	PRIDDIS SALES	45,630	337.4	15,395,116
3074	WATERTON SALES	208,703	0.0	2,087
3076	RAINBOW SALES	71	0.0	3

Unit Number	Unit Name	Annual Volume (e3m3)	DOH (Km)	Volume-Distance
3077	FIRE CREEK SALE	4,440	41.5	184,202
3078	JUDY CREEK SALE	0	0.0	0
3080	LOUISE CREEK SL	29,009	51.6	1,496,600
3082	ELK RIVER S SLS	0	0.0	0
3083	RAINBOW LK SLS	0	0.0	0
3085	DEEP VLLY CR SL	4,039	0.1	283
3086	PINE CREEK SLS	4,387	71.3	312,899
3087	GOLD CREEK SLS	20,802	37.0	769,637
3088	VALHALLA SALES	3,172	236.9	751,455
3091	OUTLET CREEK SL	91	2.0	181
3092	MOOSEHORN R SLS	7,677	25.1	192,989
3093	HARMATTAN-LEDUC	0	0.0	0
3094	BRAZEAU N SALES	100	67.9	6,806
3095	SAKWATAMAU SALE	19,377	26.9	521,128
3097	CHICKADEE CK SL	20,460	36.5	747,264
3098	DUTCH CREEK SLS	0	0.0	0
3099	SOUSA CRK E SLS	4,219	2.5	10,441
3100	HEART RIVER SLS	11,528	0.0	231
3101	CAROLINE SALES	46	241.6	11,017
3103	VIRGO SALES	4,063	13.2	53,513
3105	CRANBERRY LK SL	107,452	47.2	5,074,831
3106	CARMON CREEK SL	184	97.0	17,853
3107	FERGUSON SALES	33,786	101.4	3,427,476
3109	CALDWELL SALES	4,406	40.0	176,210
3110	MARSH HD CR W S	61	364.8	22,396
3111	MINNOW LK S. SL	1,028	8.1	8,280
3112	FALHER SALES	29,126	23.0	671,037
3113	TWINLAKES CK SL	140	93.7	13,139
3114	WEMBLEY SALES	18,825	125.9	2,370,739
3115	USONA SALES	32,499	7.4	240,880
3117	GRIZZLY SALES	28,514	31.0	883,829
3118	GILBY N#2 SALES	54	0.2	11
3119	DEADRICK CK SLS	4,042	16.4	66,202
3120	MILDRED LK SLS	1,236,125	237.8	294,008,147
3123	MILDRED LK #2 S	545,728	232.8	127,060,937
3124	DEEP VY CK S SL	0	0.0	0
3125	HUGGARD CREEK S	4,276	43.4	185,571
3128	GARRINGTON SALE	2,880	5.3	15,222
3300	OTAUWAU SALES	1,424	10.5	15,000
3301	SAULTEAUX SALES	292	19.3	5,641
3304	FORESTBURG SLS	7,259	239.8	1,740,851
3305	CHIGWELL N. SLS	3,414	0.0	58
3368	NOEL LAKE SALES	50,424	95.5	4,815,067

Unit Number	Unit Name	Annual Volume (e3m3)	DOH (Km)	Volume-Distance
3405	RIM-WEST SALES	245,069	0.0	8,087
3406	REDWATER SALES	93,964	51.1	4,803,108
3410	VIKING SALES	108,688	24.8	2,698,548
3411	MONARCH N. B SL	2,698	0.1	173
3412	WAYNE N B SALES	19,129	0.0	593
3413	ATMORE B SALES	6,966	0.0	181
3414	HANNA S B SALES	8,780	200.8	1,762,748
3416	COUSINS A SALES	0	0.0	0
3418	COUSINS C SALES	1,212	45.6	55,296
3419	INLAND SALES	976,455	244.9	239,117,445
3421	WIMBORNE SALES	0	0.0	0
3422	THORHILD SALES	3,613	0.0	83
3423	BASHAW WEST SLS	467	12.9	6,033
3424	GRANDE CENTRE S	20,066	18.8	377,102
3425	WOOD RVR SALES	60,363	28.8	1,737,497
3427	WESTLOCK SALES	3,777	0.0	181
3429	ST. PAUL SALES	18,341	46.0	843,204
3430	FERINTOSH SALES	1,682	14.2	23,850
3432	PETRO GAS PLANT	977,305	521.5	509,669,508
3434	AMOCO INLET	1,486,708	641.4	953,506,763
3435	PAN CAN INLET	312,780	540.2	168,968,319
3437	HARMATTAN SALES	461	452.2	208,325
3438	REDWATER B SL	41,200	60.5	2,492,767
3439	SHEERNESS SALES	4,432	311.6	1,381,066
3440	PROGAS PLANT	211,684	523.9	110,893,274
3444	PINCHER CRK SLS	7,030	92.7	651,436
3445	KAKWA SALES	0	0.0	0
3446	BITTERN LAKE SL	67,441	26.9	1,811,924
3448	ROSS CREEK SLS	93,808	31.2	2,923,138
3449	FLEET SALES	3,037	9.2	27,814
3452	JOFFRE EXTRACTI	89,197	81.2	7,242,728
3453	GREEN GLADE SLS	0	0.0	0
3454	PENHOLD N SALES	66,691	58.6	3,906,521
3456	ELK POINT SALES	14,398	5.2	75,113
3457	MITSUE SALES	0	0.0	0
3458	COUSINS B SALES	958,889	45.0	43,155,641
3460	LANDON LAKE SLS	10,859	0.1	880
3462	NIPISI SALES	0	0.0	0
3464	GREENCOURT W SL	17,799	7.9	141,198
3465	DEMMITT SALES	718	10.7	7,657
3467	KILLAM SALES	0	0.0	0
3468	BLEAK LAKE SLS	12,215	36.7	448,307
3469	EVERGREEN SALES	368	0.0	6

Unit Number	Unit Name	Annual Volume (e3m3)	DOH (Km)	Volume-Distance
3470	NOSEHILL CRK SL	16,789	4.4	73,470
3471	BLUE RIDGE E SL	50,141	4.5	225,303
3472	INNISFAIL SALES	1,828	11.5	21,013
3474	LLOYD CREEK SLS	0	0.0	0
3476	LAC LA BICHE SL	3,943	17.1	67,307
3477	RICINUS S SALES	0	0.0	0
3478	ONETREE SALES	20,370	0.0	407
3479	NOSEHILL CRK N.	4,868	368.4	1,793,459
3481	SAWRIDGE SALES	35,170	0.3	8,821
3482	LONE PINE CK SL	11,827	0.0	343
3483	CRAMMOND SALES	9	0.0	0
3484	CARIBOU LAKE SL	0	0.0	0
3485	SHORNCLIFFE CRK	9	63.8	574
3486	WESTERDALE SLS	3,542	0.8	2,985
3488	ARDLEY SALES	11,937	51.7	617,573
3489	ATUSIS CREEK SL	102,770	557.5	57,291,839
3490	GAETZ LAKE SLS	6,868	0.0	69
3491	JOFFRE SLS #2	574,116	80.6	46,300,416
3492	JOFFRE SLS #3	478,622	80.7	38,607,055
3493	MEYER B SALES	0	0.0	0
3494	SILVER VLY SLS	1,837	38.0	69,763
3495	CAVALIER SALES	1,216	0.0	4
3496	CHIPEWYAN RIVER	224,167	29.3	6,569,670
3497	SUNDAY CREEK SO	47,875	3.5	169,407
3562	AMOCO SALES TAP	55	192.8	10,527
3600	STORNHAM COULEE	27,334	33.3	909,151
3604	MARGUERITE L SL	59,382	182.6	10,840,366
3605	LEMING LAKE SLS	1,632,538	88.4	144,249,749
3606	LOSEMAN LAKE SL	289,033	33.3	9,623,677
3609	SARRAIL SALES	42,234	61.7	2,606,737
3610	RANFURLY SALES	27,274	55.7	1,519,665
3611	HERMIT LAKE SLS	161,007	269.4	43,376,048
3612	CONKLIN W SALES	136,554	28.3	3,859,974
3613	SHANTZ SALES	1,004	12.5	12,586
3615	HAYNES SALES	27,332	58.5	1,597,780
3616	GAS CITY SALES	25,296	34.3	867,773
3618	JENNER EAST SLS	1,858	451.7	839,152
3621	LOSEMAN LK SL#2	9,361	33.3	311,884
3622	CHEECHAM W. SLS	14,886	11.3	168,288
3623	FERINTOSH N. SL	286	30.6	8,739
3624	GODS LAKE SALES	64	120.0	7,665
3626	MIRAGE SALES	0	0.0	0
3632	EAST CALGARY SA	0	0.0	0

Unit Number	Unit Name	Annual Volume (e3m3)	DOH (Km)	Volume-Distance
3633	RUTH LK SLS	152,195	230.7	35,115,469
3634	CANOE LAKE SALE	243	0.0	9
3635	ROD LAKE SALES	1,980	38.0	75,287
3637	RUTH LK SLS #2	1,112	230.7	256,598
3639	VEGREVILLE SALE	16,834	236.0	3,972,051
3640	RUTH LK SLS #3	862	247.3	213,012
3642	VENTURES KV OIL	164,949	263.3	43,423,547
3884	COALDALE S. JCT	3,740	9.9	36,996
3885	CHIP LAKE JCT	7,383	0.0	74
5007	HOUSE RIVER	29,559	84.6	2,500,363
5024	CROW LAKE SALES	0	0.0	0
6903	MCNEILL A UTIL	60	635.7	38,271
	Subtotal for Intra-Alberta deliveries	**14,305,815**	**239.2**	**3,421,504,540**

APPENDIX 2B: COST OF SERVICE STUDY ALTERNATIVE ALLOCATION METHODOLOGIES

Table of Contents

1.0 INTRODUCTION

This appendix outlines alternative cost allocation methodologies that NGTL has considered in its COS study analysis. The COS study for the existing methodology is included in Appendix 2A of the Application. Each section of this appendix from Section 2 to Section 7 contains a standalone description and the results of one alternative cost allocation methodology. The following information is provided for each alternative:

- An overview of the allocation methodology;
- One or two diagrams that provides a pictorial illustration of the allocation methodology;
- A diagram that illustrates the allocation of the revenue requirement to each tariff service;
- A detailed description of each step in the allocation process; and
- A table containing the revenues, volumes and rates for all tariff services for the test year.

2.0 COST ALLOCATION METHODOLOGY FOR ALTERNATIVE 1

2.1 OVERVIEW

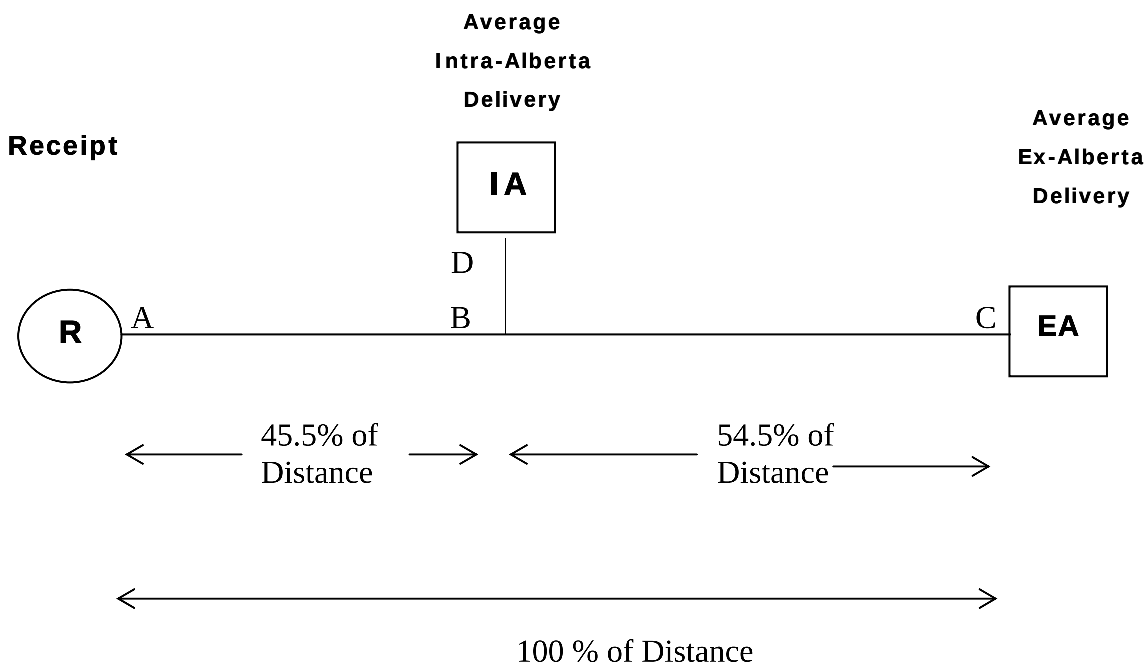
This alternative is similar to the existing methodology; however the relationship of transmission costs between export and intra-Alberta markets has been adjusted to the long-term average DOH, which reflects that on average volumes delivered intra-Alberta travel 45.5% of the distance of volumes being delivered to ex-Alberta delivery points. The relationship of transmission costs between export and intra-Alberta markets has therefore been modified to be 2.2:1. As with the existing methodology, every service has a system average metering component. In the case of FT-A this is the entire rate as transmission costs are included in the FT-R rate.

Diagram 2.1-1 illustrates the allocation of transmission costs between intra and ex-Alberta markets in order to establish a 2.2:1 ratio. Specifically the transmission component of the FT-R rate is represented by the line from point A to point B (AB), the transmission component of the FT-D rate is represented by the line from point B to point C (BC) and the transmission component of the FT-A rate is represented by the line from point B to point D (BD). Therefore the transmission for intra-Alberta markets is the sum of AB and BD and the transmission for export markets is the sum of AB and BC. In order to establish a 2.2:1 ratio then (AB + BC) must equal 2.2 x (AB + BD) or stated another way (AB + BD) must equal 45.5% x (AB + BC).

Diagram 2.1-2 is a pictorial representation of the cost allocation methodology used to determine the rates for the major services. The transmission costs are allocated to establish the 2.2:1 ratio between export and intra-Alberta markets and every rate incorporates a metering charge of 1.42¢/Mcf.

Diagram 2.1-1

Illustration of Allocation of Transmission Costs Between Intra & Ex-Alberta Deliveries

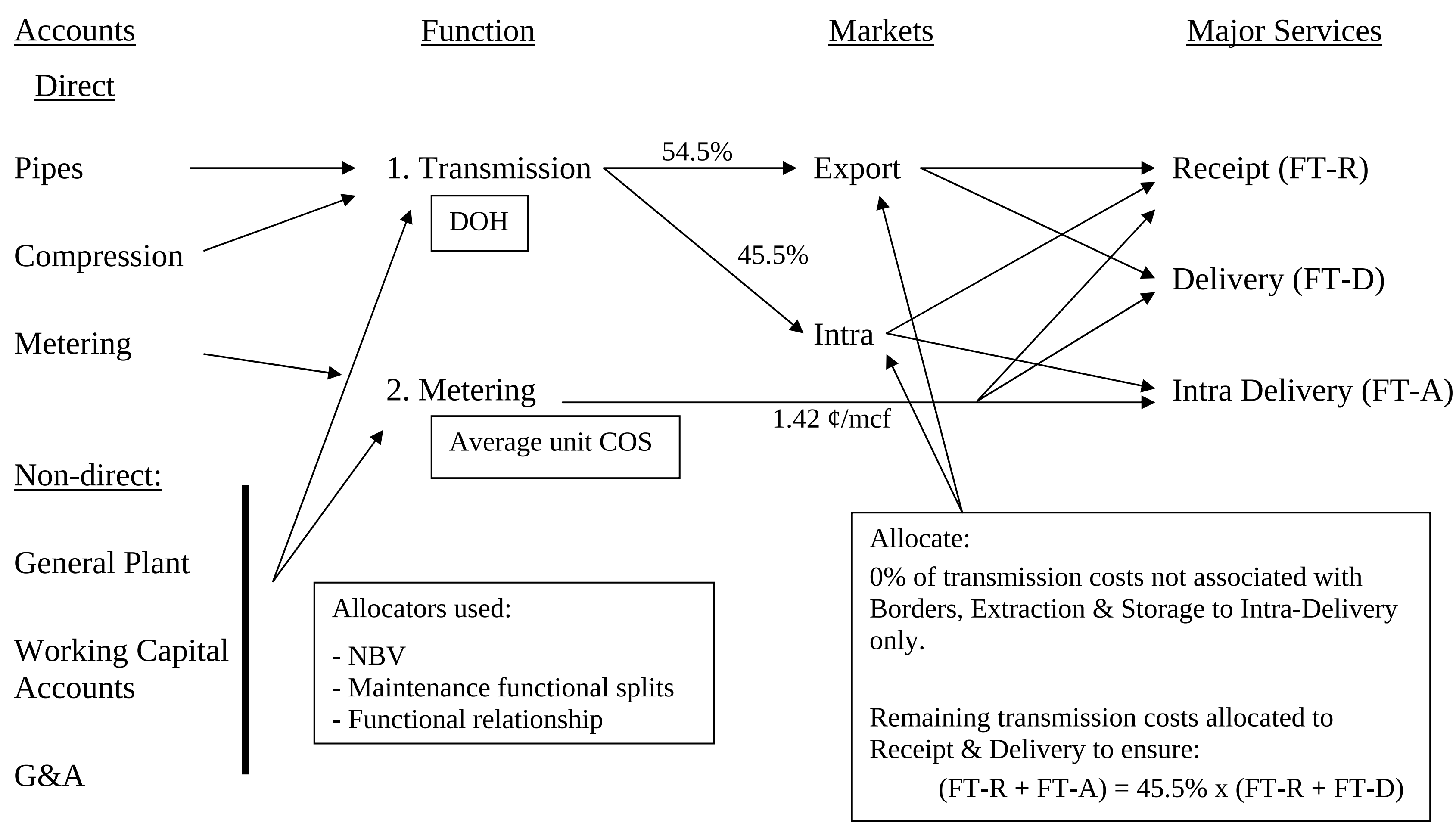


Where:

- AB represents the transmission component of FT-R service.
- BC represents the transmission component of FT-D service.
- BD represents the transmission component of FT-A service, which has been set to zero in this alternative.
- Transmission costs are allocated to AB and BC in order to establish a 2.2:1 ratio between intra and export markets by ensuring (AB+BD) = 45.5% x (AB + BC).

Diagram 2.1-2

Application of Cost Allocations to Rates Determination



2.2 ALLOCATION OF REVENUE REQUIREMENT TO ALL TARIFF SERVICES

Diagram 2.2-1 details all the steps required to allocate the total revenue requirement for the test year to all tariff services. In order to gain a fuller understanding of the allocation process, each box on the diagram is explained below. Table 2.2-1 provides the forecasted costs, volumes and rates for all services for the test year.

2.2.1 Oval 1 – COS for Metering Facility

This is the COS for metering facilities as determined by the base year COS Study.

2.2.2 Box 1a – Total Service Volumes

This is the total metered volumes for all services for the base year.

2.2.3 Box 1b – Metering Charge

This is the system average metering charge which is included in rates for all services except FT-X and IT-S. It is determined by dividing the COS for metering facilities (Oval 1) by total service volumes (Box 1a).

2.2.4 Oval 2 – 0% of COS for Transmission Facilities not associated with Border, Extraction, or Storage

No costs associated with transmission facilities have been applied to intra-Alberta delivery services in this alternative.

2.2.5 Box 2a – Intra-Alberta Delivery Volumes

This is the 2005 forecasted intra-Alberta delivery volumes. It includes volumes transported under FT-A and FT-P services.

2.2.6 Box 2b – Intra Transmission Charge

This is the intra transmission charge to be included in the FT-A rate. It is determined by dividing the COS for transmission facilities not associated with border, extraction or storage (Oval 2) by intra-Alberta delivery volumes (Box 2a). In this alternative, as no costs associated with transmission facilities have been directly applied to intra-Alberta services, the direct intra transmission charge is zero. Transmission costs are included in the FT-R rate and recovered from intra-Alberta delivery shippers via the price of gas.

2.2.7 Oval 3 – DOH Ratio

This is the relationship between the average distance gas destined for intra-Alberta markets travels compared to the average distance gas destined for ex-Alberta markets travels. The long term historical average of this relationship has been 45.5% which is the value used for this methodology.

2.2.8 Box 4 – Total Revenue Requirement

This is the revenue requirement for the test year.

2.2.9 Box 4a – Other Service Revenue

This is the revenue that is collected from services other than the primary services of FT-R, FT-D, and FT-A.

OS and PT revenues are calculated based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2, and LRS-3 services are calculated based on EUB approved rates and forecasted volumes.

Revenues from FT-P service are based on the different distance bands which apply for each FT-P contract and the forecasted volumes for each contract. The rates for the distance bands are a function of the average FT-R rate. Revenues from FT-RN and IT-R services are based on premiums to the FT-R rate and forecasted volumes for each of these services. Revenues from FT-DW, STFT, and IT-D are based on premiums to the FT-D rate and the forecasted volumes for each of these services. Therefore the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D and thus is determined in conjunction with Box 4d.

2.2.10 Box 4b – Primary Service Revenue

This is the revenue requirement that needs to be allocated among the primary services. It is determined by subtracting the other service revenue (Box 4a) from the total revenue requirement (Box 4).

2.2.11 Box 4d – Allocate Revenue to Primary Services

This is the step where the cost allocation methodology is used to allocate the revenue requirement to each primary service (FT-R, FT-D, and FT-A). The revenue requirement is allocated according to the following principles:

1. The metering component of each rate equals the metering charge (Box 1b);

2. The transmission component of the FT-A rate equals the intra transmission charge (Box 2b), which in this case is zero; and

3. The transmission components of the average FT-R and the FT-D rates are set such that the ratio of the transmission component of the primary services required to provide intra-Alberta service (FT-R + FT-A) divided by the transmission component of the primary services required to provide ex-Alberta service (FT-R + FT-D) equals the intra-Alberta to ex-Alberta DOH ratio (Oval 3).

   For this methodology the DOH ratio in Oval 3 is 45.5%. Thus principle 3 can be restated as transmission component of (FT-R + FT-A) = 45.5% x transmission component of (FT-R + FT-D).

2.2.12 Box 5 – FT-R Revenue

This is the revenue requirement that needs to be allocated to FT-R service and is a direct output of Box 4d.

2.2.13 Box 5a – FT-R Contract Demand

This is the forecasted FT-R contract demand quantity for the test year.

2.2.14 Box 5b – Average Receipt Price

This is the average FT-R price. It is determined by dividing the FT-R revenue (Box 5) by the FT-R contract demand (Box 5a).

2.2.15 Box 5c – Receipt Point Allocation

This is the distance-diameter algorithm or allocation methodology used to determine the individual receipt point prices. Each receipt point's price is determined by that receipt point's share of the total volume weighted distance diameter allocation units. Individual receipt point prices will vary within a floor and ceiling band of ± 8 cents/Mcf from the average FT-R price (Box 5b).

2.2.16 Box 5d – Receipt Point Specific Rates

Based on the receipt point allocation (Box 5c), each receipt point rate is determined.

2.2.17 Box 6 – FT-D Revenue

This is the revenue requirement that needs to be allocated to FT-D service and is a direct output of Box 4d.

2.2.18 Box 6a – FT-D Contract Demand

This is the forecasted FT-D contract demand for the test year.

2.2.19 Box 6b – FT-D Rate

The FT-D rate is determined by dividing the FT-D revenue (Box 6) by the FT-D contract demand (Box 6a).

2.2.20 Box 7 – FT-A Revenue

This is the revenue requirement that needs to be allocated to FT-A service and is a direct output of Box 4d.

2.2.21 Box 7a – FT-A Volume

This is the forecasted FT-A volume for the test year.

2.2.22 Box 7b – FT-A Rate

The FT-A rate is determined by dividing the FT-A revenue (Box 7) by the FT-A volume (Box 7a).

Diagram 2.2-1 Illustrative Rate Calculation

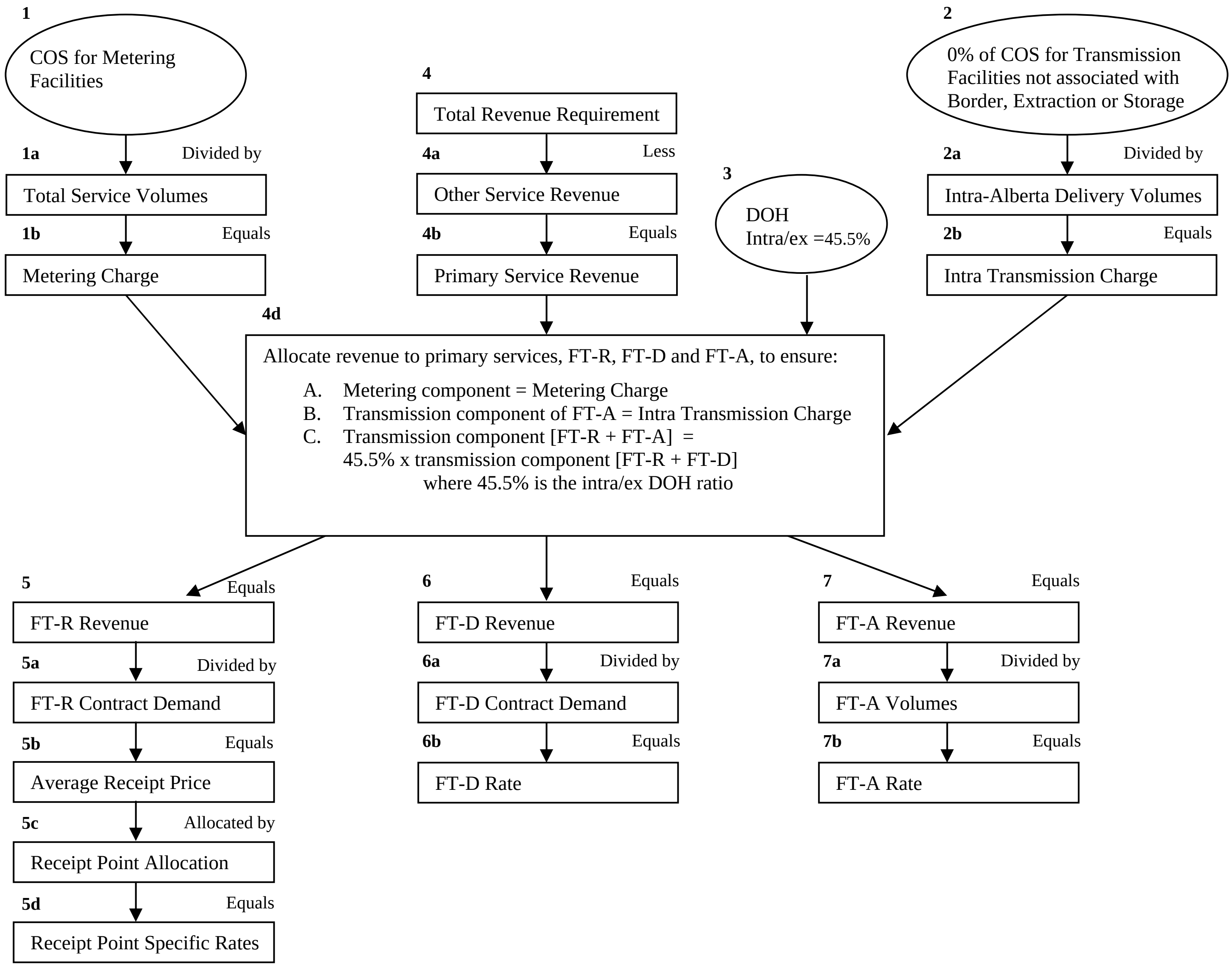


Table 2.2-1 – Allocation of 2005 Revenue Requirement to Services

Service	Revenue ($Millions)	Forecast Volume (10^6m^3)	Rates ($/$10^3m^3$)
FT-R[1]	419.6	82,271	155.25
FT-D	454.7	75,640	182.93
FT-A	5.3	10,557	0.50
FT-RN[2]	4.9	696	215.78
FT-P[2]	20.5	3,916	159.31
LRS[2]	43.3	6,733	195.87
LRS-2[3]	0.7	381	50,000/month
LRS-3[3]	3.3	515	192.37
STFT[2]	0.0	-	-
FT-DW[2]	0.0	-	-
IT-R[2]	114.4	21,306	5.37
IT-D[5]	70.8	10,715	6.61
FCS	4.9	n/a	n/a
CO_2[2]	15.4	n/a	n/a
PT[4]	0.9	n/a	n/a
Other Service	1.1	n/a	n/a
Total	**1,160.0**		

Notes:
1. Rate quoted is a volume-weighted average for a three-year contract term.
2. Rate quoted is volume-weighted average.
3. Revenue quoted includes NGTL shareholder contribution.
4. New service only forecasted in 2005.
5. Forecast quantity is net of Alternate Access.

3.0 COST ALLOCATON METHODOLOGY FOR ALTERNATIVE 2

3.1 OVERVIEW

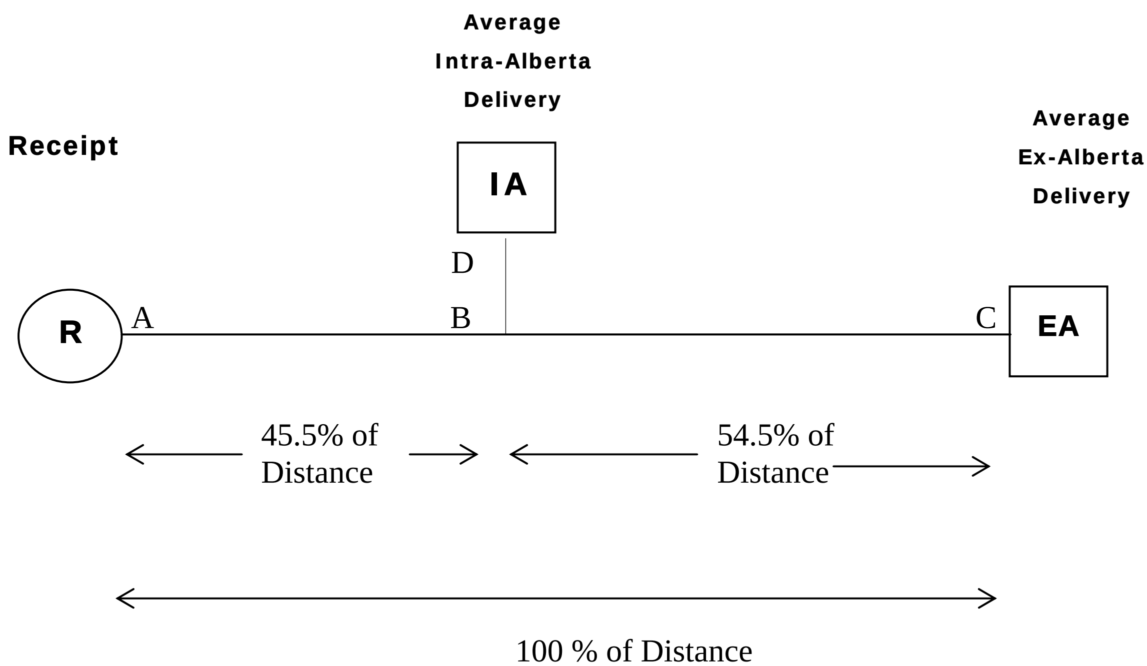
This alternative is similar to the existing methodology; however, the relationship of transmission costs between export and intra-Alberta markets has been adjusted to the long-term average DOH, which reflects that on average volumes delivered intra-Alberta travel 45.5% of the distance of volumes delivered to ex-Alberta delivery points. The relationship of transmission costs between export and intra-Alberta markets has therefore been modified to be 2.2:1. As with the existing methodology, every service has a system average metering component. However, with this alternative a direct transmission component has been included in the FT-A rate. This rate component is calculated based on the cost of service analysis of the transmission facilities not associated with export, storage or extraction services. In other words it is based on the cost of service of facilities that only provide receipt and intra-Alberta delivery services. As a result 50% of the costs of these facilities have been allocated to the transmission component of the FT-A rate. In order to maintain the 2.2:1 ratio and include a transmission component in the FT-A rate, both the FT-R and FT-D rates need to be adjusted.

Diagram 3.1-1 illustrates the allocation of transmission costs between intra and ex-Alberta markets in order to establish a 2.2:1 ratio. Specifically the transmission component of the FT-R rate is represented by the line from point A to point B (AB), the transmission component of the FT-D rate is represented by the line from point B to point C (BC) and the transmission component of the FT-A rate is represented by the line from point B to point D (BD). Therefore the transmission for intra-Alberta markets is the sum of AB and BD and the transmission for export markets is the sum of AB and BC. In order to establish a 2.2:1 ratio then (AB + BC) must equal 2.2 x (AB + BD) or stated another way (AB + BD) must equal 45.5% x (AB + BC).

Diagram 3.1-2 is a pictorial representation of the cost allocation methodology used to determine the rates for the major services. The transmission costs are allocated to establish the 2.2:1 ratio between export and intra-Alberta markets and every rate incorporates a metering charge of 1.42¢/Mcf.

Diagram 3.1-1

Illustration of Allocation of Transmission Costs Between Intra & Ex-Alberta Markets

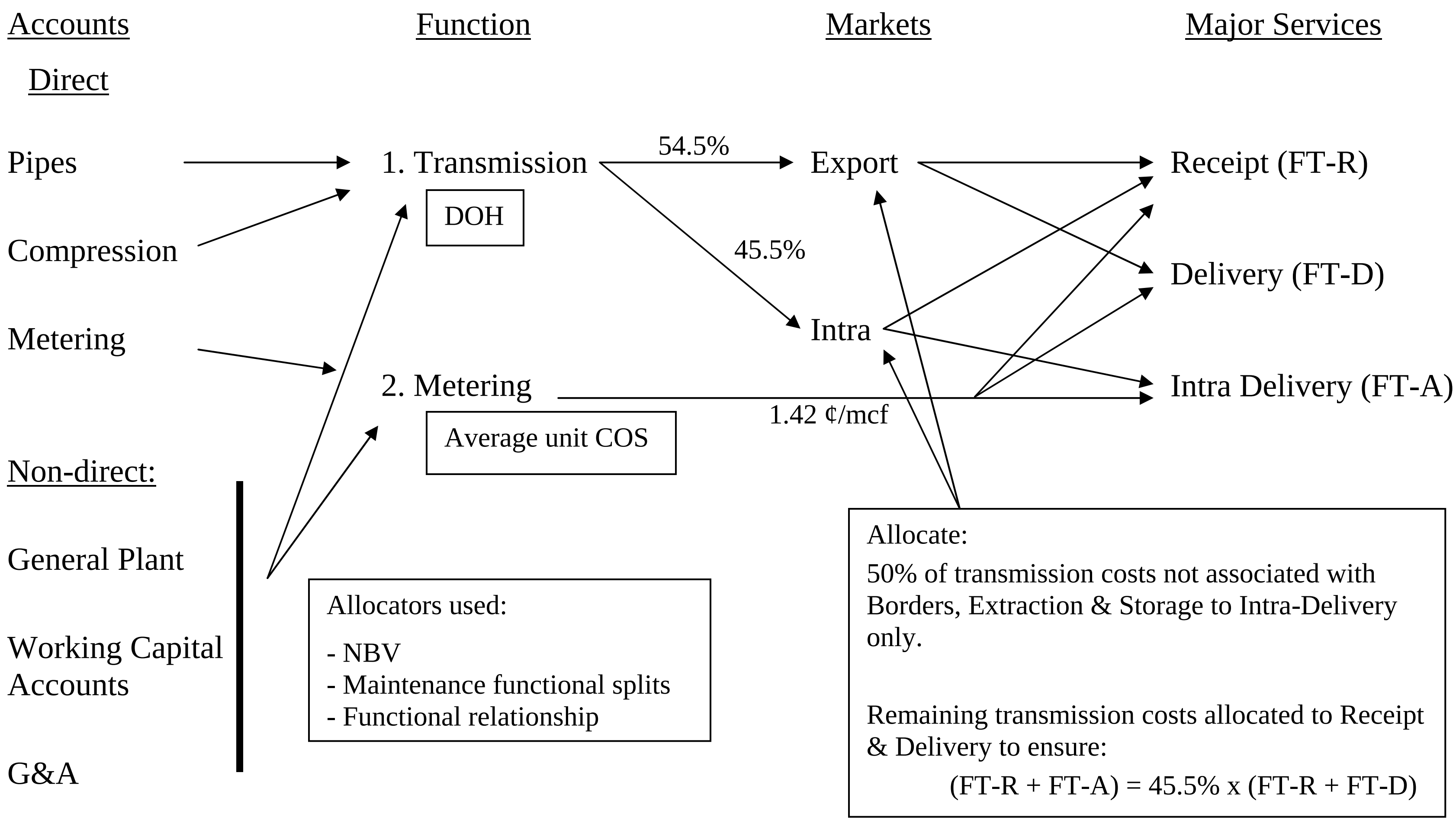


Where:

- AB represents the transmission component of FT-R service.
- BC represents the transmission component of FT-D service.
- BD represents the transmission component of FT-A service.
- BD is allocated 50% of the cost of service of transmission facilities not associated with borders, extraction or storage services.
- Transmission costs are allocated to AB and BC in order to establish a 2.2:1 ratio between intra and export markets by ensuring (AB+BD) = 45.5% x (AB + BC).

Diagram 3.1-2

Application of Cost Allocations to Rates Determination



3.2 ALLOCATION OF REVENUE REQUIREMENT TO ALL TARIFF SERVICES

Diagram 3.2-1 details all the steps required to allocate the total revenue requirement for the test year to all tariff services. In order to gain a fuller understanding of the allocation process, each box on the diagram is explained below. Table 3.2-1 provides the forecasted costs, volumes and rates for all services for the test year.

3.2.1 Oval 1 – COS for Metering Facility

This is the COS for metering facilities as determined by the base year COS Study.

3.2.2 Box 1a – Total Service Volumes

This is the total metered volumes for all services for the base year.

3.2.3 Box 1b – Metering Charge

This is the system average metering charge which is included in rates for all services except FT-X and IT-S. It is determined by dividing the COS for metering facilities (Oval 1) by total service volumes (Box 1a).

3.2.4 Oval 2 – 50% of COS for Transmission Facilities not associated with Border, Extraction, or Storage

This is 50% of the COS of transmission facilities not associated with border, extraction or storage or conversely it is 50% of the COS of transmission facilities only associated with receipt and intra-Alberta delivery services. The detailed COS methodology is described in Section 2.4.2 of this Application. Only 50% of the COS is included as these facilities are joint use or common facilities used for both receipt and intra-Alberta delivery services and thus only 50% of the costs are applied directly to intra-Alberta delivery services.

3.2.5 Box 2a – Intra-Alberta Delivery Volumes

This is the 2005 forecasted intra-Alberta delivery volumes. It includes volumes transported under FT-A and FT-P services.

3.2.6 Box 2b – Intra Transmission Charge

This is the intra transmission charge to be included in the FT-A rate. It is determined by dividing the 50% of COS for transmission facilities not associated with border, extraction or storage (Oval 2) by intra-Alberta delivery volumes (Box 2a).

3.2.7 Oval 3 – DOH Ratio

This is the relationship between the average distance gas destined for intra-Alberta markets travels compared to the average distance gas destined for ex-Alberta markets travels. The long term historical average of this relationship has been 45.5% which is the value used for this methodology.

3.2.8 Box 4 – Total Revenue Requirement

This is the revenue requirement for the test year.

3.2.9 Box 4a – Other Service Revenue

This is the revenue that is collected from services other than the primary services of FT-R, FT-D, and FT-A.

OS and PT revenues are calculated based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2, and LRS-3 services are calculated based on EUB approved rates and forecasted volumes.

Revenues from FT-P service are based on the different distance bands which apply for each FT-P contract and the forecasted volumes for each contract. The rates for the distance bands are a function of the average FT-R rate. Revenues from FT-RN and IT-R services are based on premiums to the FT-R rate and forecasted volumes for each of these services. Revenues from FT-DW, STFT, and IT-D are based on premiums to the FT-D rate and the forecasted volumes for each of these services. Therefore the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D and thus is determined in conjunction with Box 4d.

3.2.10 Box 4b – Primary Service Revenue

This is the revenue requirement that needs to be allocated among the primary services. It is determined by subtracting the other service revenue (Box 4a) from the total revenue requirement (Box 4).

3.2.11 Box 4d – Allocate Revenue to Primary Services

This is the step where the cost allocation methodology is used to allocate the revenue requirement to each primary service (FT-R, FT-D, and FT-A). The revenue requirement is allocated according to the following principles:

1. The metering component of each rate equals the metering charge (Box 1b);

2. The transmission component of the FT-A rate equals the intra transmission charge (Box 2b); and

3. The transmission components of the average FT-R and the FT-D rates are set such that the ratio of the transmission component of the primary services required to provide intra-Alberta service (FT-R + FT-A) divided by the transmission component of the primary services required to provide ex-Alberta service (FT-R + FT-D) equals the intra-Alberta to ex-Alberta DOH ratio (Oval 3).

For this methodology the DOH ratio in Oval 3 is 45.5%. Thus principle 3 can be restated as transmission component of (FT-R + FT-A) = 45.5% x transmission component of (FT-R + FT-D).

3.2.12 Box 5 – FT-R Revenue

This is the revenue requirement that needs to be allocated to FT-R service and is a direct output of Box 4d.

3.2.13 Box 5a – FT-R Contract Demand

This is the forecasted FT-R contract demand quantity for the test year.

3.2.14 Box 5b – Average Receipt Price

This is the average FT-R price. It is determined by dividing the FT-R revenue (Box 5) by the FT-R contract demand (Box 5a).

3.2.15 Box 5c – Receipt Point Allocation

This is the distance-diameter algorithm or allocation methodology used to determine the individual receipt point prices. Each receipt point's price is determined by that receipt point's share of the total volume weighted distance diameter allocation units. Individual receipt point prices will vary within a floor and ceiling band of ± 8 cents/Mcf from the average FT-R price (Box 5b).

3.2.16 Box 5d – Receipt Point Specific Rates

Based on the receipt point allocation (Box 5c), each receipt point rate is determined.

3.2.17 Box 6 – FT-D Revenue

This is the revenue requirement that needs to be allocated to FT-D service and is a direct output of Box 4d.

3.2.18 Box 6a – FT-D Contract Demand

This is the forecasted FT-D contract demand for the test year.

3.2.19 Box 6b – FT-D Rate

The FT-D rate is determined by dividing the FT-D revenue (Box 6) by the FT-D contract demand (Box 6a).

3.2.20 Box 7 – FT-A Revenue

This is the revenue requirement that needs to be allocated to FT-A service and is a direct output of Box 4d.

3.2.21 Box 7a – FT-A Volume

This is the forecasted FT-A volume for the test year.

3.2.22 Box 7b – FT-A Rate

The FT-A rate is determined by dividing the FT-A revenue (Box 7) by the FT-A volume (Box 7a).

Diagram 3.2-1 Illustrative Rate Calculation

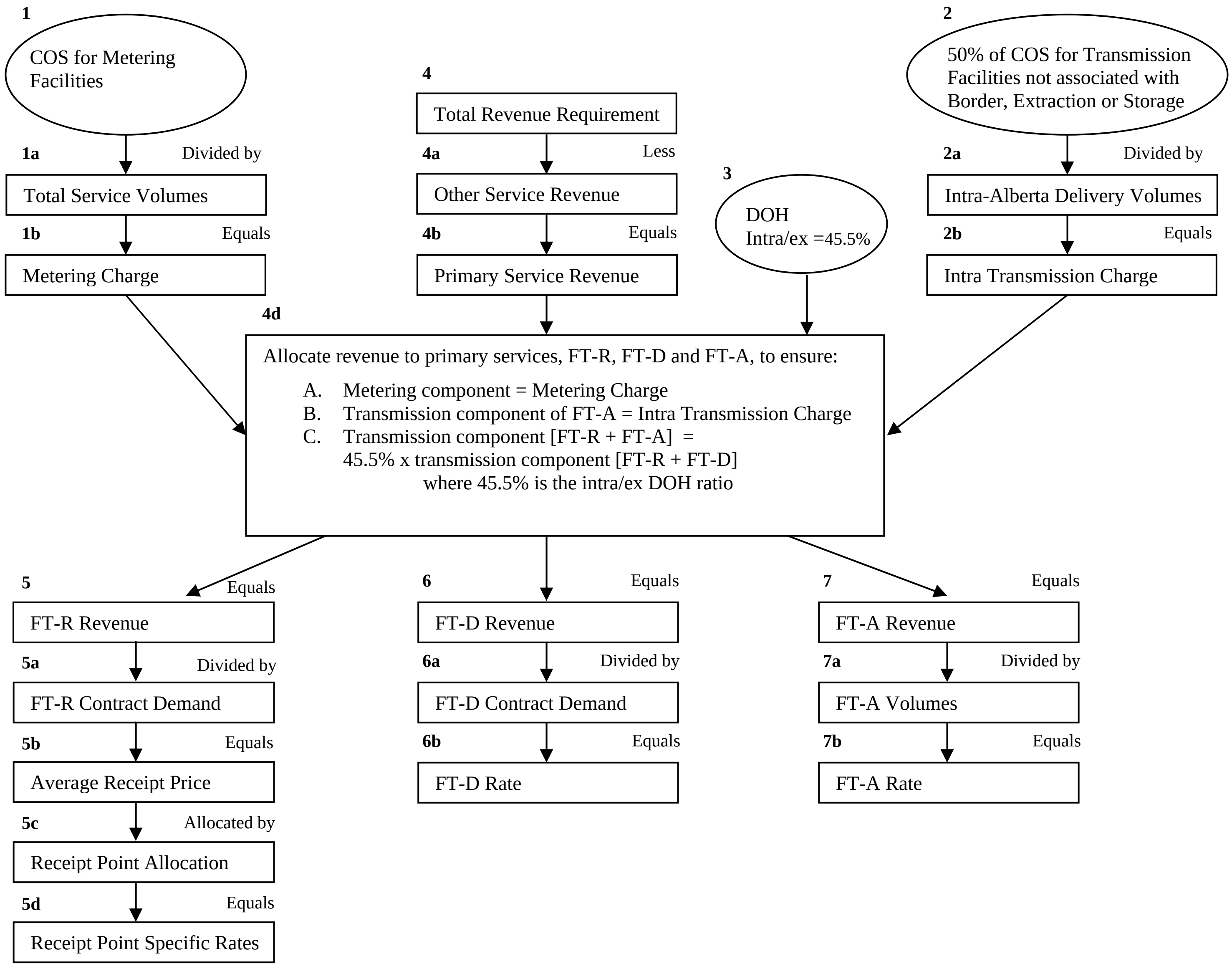


Table 3.2-1 – Allocation of 2005 Revenue Requirement to Services

Service	**Revenue ($Millions)**	**Forecast Volume (10^6m^3)**	**Rates ($\$/10^3m^3$)**
FT-R[1]	407.2	82,271	150.64
FT-D	467.5	75,640	188.10
FT-A	7.0	10,557	0.66
FT-RN[2]	4.8	696	210.71
FT-P[2]	19.9	3,916	154.71
LRS[2]	43.3	6,733	195.87
LRS-2[3]	0.7	381	50,000/month
LRS-3[3]	3.3	515	192.37
STFT[2]	0.0	-	-
FT-DW[2]	0.0	-	-
IT-R[2]	111.0	21,306	5.21
IT-D[5]	72.9	10,715	6.80
FCS	4.9	n/a	n/a
CO_2[2]	15.4	n/a	n/a
PT[4]	0.9	n/a	n/a
Other Service	1.1	n/a	n/a
Total	**1,160.0**		

Notes:
1. Rate quoted is a volume-weighted average for a three-year contract term.
2. Rate quoted is volume-weighted average.
3. Revenue quoted includes NGTL shareholder contribution.
4. New service only forecasted in 2005.
5. Forecast quantity is net of Alternate Access.

4.0 COST ALLOCATION METHODOLOGY FOR ALTERNATIVE 3

4.1 OVERVIEW

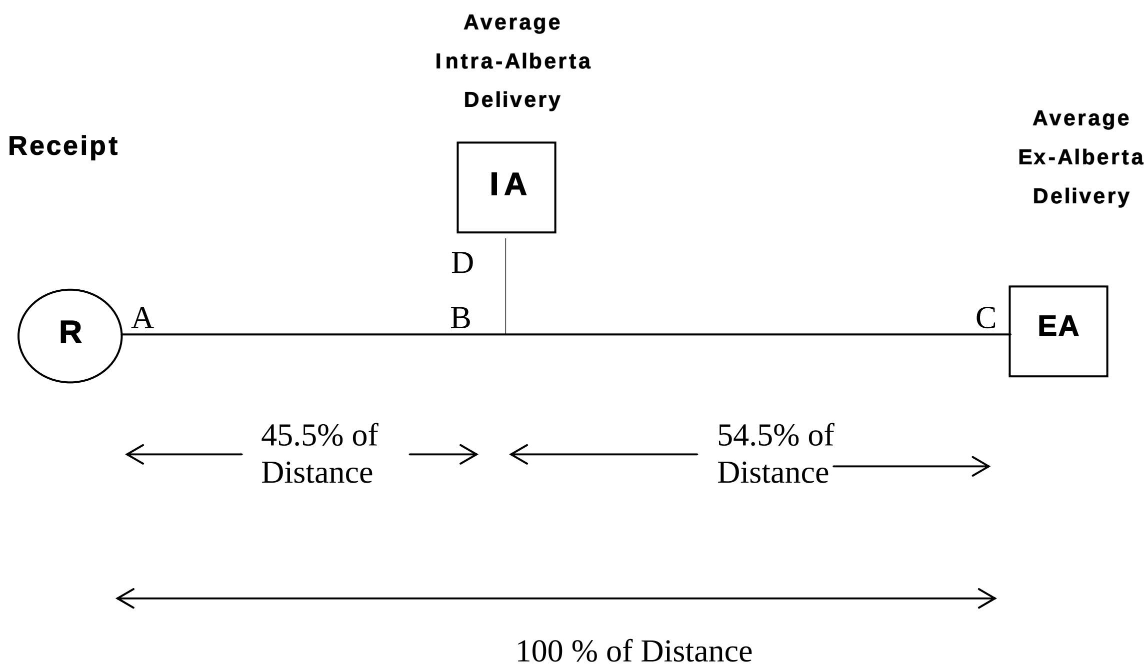
This alternative is similar to the existing methodology; however the relationship of transmission costs between export and intra-Alberta markets has been adjusted to the long-term average DOH, which reflects that on average volumes delivered intra-Alberta travel 45.5% of the distance of volumes being delivered to ex-Alberta delivery points. The relationship of transmission costs between export and intra-Alberta markets has therefore been modified to be 2.2:1. As with the existing methodology, every service has a system average metering component. However, with this alternative a direct transmission component has been included in the FT-A rate. This rate component is calculated based on the cost of service analysis of the transmission facilities not associated with export, storage or extraction services and includes TBO costs for the Ventures, ATCO and Kearl Lake transportation agreements. In other words it is based on the cost of service of facilities and TBOs that only provide receipt and intra-Alberta delivery services. As a result 50% of these costs have been allocated to the transmission component of the FT-A rate. In order to maintain the 2.2:1 ratio and include a transmission component in the FT-A rate, both the FT-R and FT-D rates need to be adjusted.

Diagram 4.1-1 illustrates the allocation of transmission costs between intra and ex-Alberta markets in order to establish a 2.2:1 ratio. Specifically the transmission component of the FT-R rate is represented by the line from point A to point B (AB), the transmission component of the FT-D rate is represented by the line from point B to point C (BC) and the transmission component of the FT-A rate is represented by the line from point B to point D (BD). Therefore the transmission for intra-Alberta markets is the sum of AB and BD and the transmission for export markets is the sum of AB and BC. In order to establish a 2.2:1 ratio then (AB + BC) must equal 2.2 x (AB + BD) or stated another way (AB + BD) must equal 45.5% x (AB + BC).

Diagram 4.1-2 is a pictorial representation of the cost allocation methodology used to determine the rates for the major services. The transmission costs are allocated to establish the 2.2:1 ratio between export and intra-Alberta markets and every rate incorporates a metering charge of 1.42¢/Mcf.

Diagram 4.1-1

Illustration of Allocation of Transmission Costs Between Intra & Ex-Alberta Markets

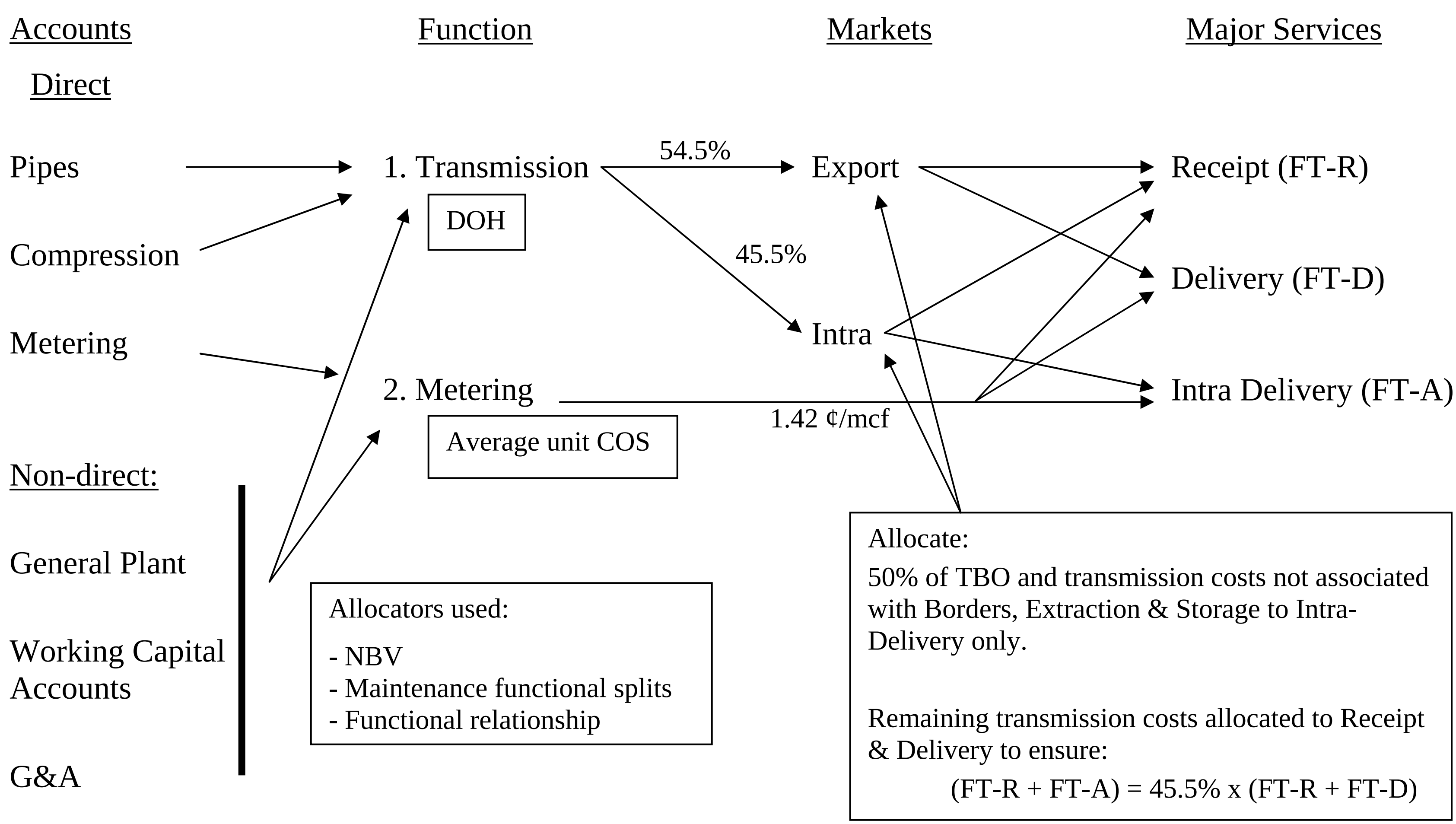


Where:

- AB represents the transmission component of FT-R service.
- BC represents the transmission component of FT-D service.
- BD represents the transmission component of FT-A service.
- BD is allocated 50% of the cost of service of transmission facilities not associated with borders, extraction or storage services and 50% of the TBO costs for the Ventures, ATCO and Kearl Lake TBO agreements.
- Transmission costs are allocated to AB and BC in order to establish a 2.2:1 ratio between intra and export markets by ensuring (AB+BD) = 45.5% x (AB + BC).

Diagram 4.1-2

Application of Cost Allocations to Rates Determination



4.2 ALLOCATION OF REVENUE REQUIREMENT TO ALL TARIFF SERVICES

Diagram 4.2-1 details all the steps required to allocate the total revenue requirement for the test year to all tariff services. In order to gain a fuller understanding of the allocation process, each box on the diagram is explained below. Table 4.2-1 provides the forecasted costs, volumes and rates for all services for the test year.

4.2.1 Oval 1 – COS for Metering Facility

This is the COS for metering facilities as determined by the base year COS Study.

4.2.2 Box 1a – Total Service Volumes

This is the total metered volumes for all services for the base year.

4.2.3 Box 1b – Metering Charge

This is the system average metering charge which is included in rates for all services except FT-X and IT-S. It is determined by dividing the COS for metering facilities (Oval 1) by total service volumes (Box 1a).

4.2.4 Oval 2 – 50% of TBO and COS for Transmission Facilities not associated with Border, Extraction, or Storage

This is 50% of the COS of transmission facilities not associated with border, extraction or storage or conversely it is 50% of the COS of transmission facilities only associated with receipt and intra-Alberta delivery services. The detailed COS methodology is described in Section 2.4.2 of this Application. It also includes 50% of the costs for the Ventures, ATCO and Kearl Lake TBO agreements. Only 50% of these costs are included as they are joint use or common facilities used for both receipt and intra-Alberta delivery services and thus only 50% of the costs are directly applied to intra-Alberta delivery services.

4.2.5 Box 2a – Intra-Alberta Delivery Volumes

This is the 2005 forecasted intra-Alberta delivery volumes. It includes volumes transported under FT-A and FT-P services.

4.2.6 Box 2b – Intra Transmission Charge

This is the intra transmission charge to be included in the FT-A rate. It is determined by dividing the 50% of TBO and transmission costs for facilities not associated with border, extraction or storage (Oval 2) by intra-Alberta delivery volumes (Box 2a).

4.2.7 Oval 3 – Distance of Haul (DOH)

This is the relationship between the average distance gas destined for intra-Alberta markets travels compared to the average distance gas destined for ex-Alberta markets travels. The long term historical average of this relationship has been 45.5% which is the value used for this methodology.

4.2.8 Box 4 – Total Revenue Requirement

This is the revenue requirement for the test year.

4.2.9 Box 4a – Other Service Revenue

This is the revenue that is collected from services other than the primary services of FT-R, FT-D, and FT-A.

OS and PT revenues are calculated based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2, and LRS-3 services are calculated based on EUB approved rates and forecasted volumes.

Revenues from FT-P service are based on the different distance bands which apply for each FT-P contract and the forecasted volumes for each contract. The rates for the distance bands are a function of the average FT-R rate. Revenues from FT-RN and IT-R services are based on premiums to the FT-R rate and forecasted volumes for each of these services. Revenues from FT-DW, STFT, and IT-D are based on premiums to the FT-D rate and the forecasted volumes for each of these services. Therefore the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D and thus is determined in conjunction with Box 4d.

4.2.10 Box 4b – Primary Service Revenue

This is the revenue requirement that needs to be allocated among the primary services. It is determined by subtracting the other service revenue (Box 4a) from the total revenue requirement (Box 4).

4.2.11 Box 4d – Allocate Revenue to Primary Services

This is the step where the cost allocation methodology is used to allocate the revenue requirement to each primary service (FT-R, FT-D, and FT-A). The revenue requirement is allocated according to the following principles:

1. The metering component of each rate equals the metering charge (Box 1b);

2. The transmission component of the FT-A rate equals the intra transmission charge (Box 2b); and

3. The transmission components of the average FT-R and the FT-D rates are set such that the ratio of the transmission component of the primary services required to provide intra-Alberta service (FT-R + FT-A) divided by the transmission component of the primary services required to provide ex-Alberta service (FT-R + FT-D) equals the intra-Alberta to ex-Alberta DOH ratio (Oval 3).

   For this methodology the DOH ratio in Oval 3 is 45.5%. Thus principle 3 can be restated as transmission component of (FT-R + FT-A) = 45.5% x transmission component of (FT-R + FT-D).

4.2.12 Box 5 – FT-R Revenue

This is the revenue requirement that needs to be allocated to FT-R service and is a direct output of Box 4d.

4.2.13 Box 5a – FT-R Contract Demand

This is the forecasted FT-R contract demand quantity for the test year.

4.2.14 Box 5b – Average Receipt Price

This is the average FT-R price. It is determined by dividing the FT-R revenue (Box 5) by the FT-R contract demand (Box 5a).

4.2.15 Box 5c – Receipt Point Allocation

This is the distance-diameter algorithm or allocation methodology used to determine the individual receipt point prices. Each receipt point's price is determined by that receipt point's share of the total volume weighted distance diameter allocation units. Individual receipt point prices will vary within a floor and ceiling band of ± 8 cents/Mcf from the average FT-R price (Box 5b).

4.2.16 Box 5d – Receipt Point Specific Rates

Based on the receipt point allocation (Box 5c), each receipt point rate is determined.

4.2.17 Box 6 – FT-D Revenue

This is the revenue requirement that needs to be allocated to FT-D service and is a direct output of Box 4d.

4.2.18 Box 6a – FT-D Contract Demand

This is the forecasted FT-D contract demand for the test year.

4.2.19 Box 6b – FT-D Rate

The FT-D rate is determined by dividing the FT-D revenue (Box 6) by the FT-D contract demand (Box 6a).

4.2.20 Box 7 – FT-A Revenue

This is the revenue requirement that needs to be allocated to FT-A service and is a direct output of Box 4d.

4.2.21 Box 7a – FT-A Volume

This is the forecasted FT-A volume for the test year.

4.2.22 Box 7b – FT-A Rate

The FT-A rate is determined by dividing the FT-A revenue (Box 7) by the FT-A volume (Box 7a).

Diagram 4.2-1 Illustrative Rate Calculation

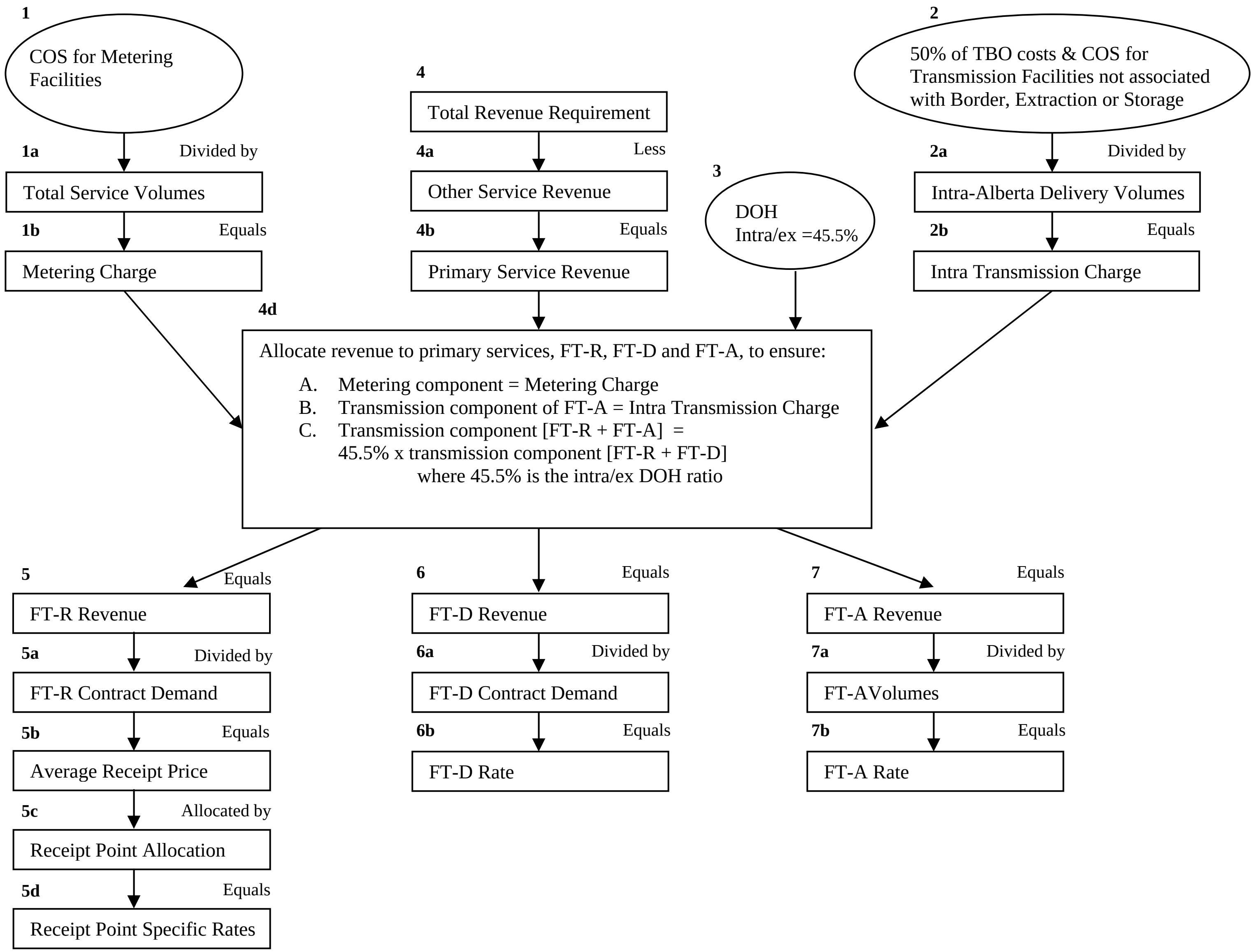


Table 4.2-1 – Allocation of 2005 Revenue Requirement to Services

Service	**Revenue ($Millions)**	**Forecast Volume (10^6m^3)**	**Rates ($/$10^3m^3$)**
FT-R[1]	376.1	82,271	139.14
FT-D	499.7	75,640	201.05
FT-A	11.2	10,557	1.06
FT-RN[2]	4.5	696	198.05
FT-P[2]	18.4	3,916	143.19
LRS[2]	43.3	6,733	195.87
LRS-2[3]	0.7	381	50,000/month
LRS-3[3]	3.3	515	192.37
STFT[2]	0.0	-	-
FT-DW[2]	0.0	-	-
IT-R[2]	102.4	21,306	4.81
IT-D[5]	77.9	10,715	7.27
FCS	4.9	n/a	n/a
CO_2[2]	15.4	n/a	n/a
PT[4]	0.9	n/a	n/a
Other Service	1.1	n/a	n/a
Total	**1,160.0**		

Notes:
1. Rate quoted is a volume-weighted average for a three-year contract term.
2. Rate quoted is volume-weighted average.
3. Revenue quoted includes NGTL shareholder contribution.
4. New service only forecasted in 2005.
5. Forecast quantity is net of Alternate Access.

5.0 COST ALLOCATION METHODOLOGY FOR ALTERNATIVE 4

5.1 OVERVIEW

This methodology is similar to the existing methodology as a system average metering charge is included in each service rate. Revenue for the metering charge is deducted from the test year's revenue requirement, which yields a transmission revenue requirement. The test year's transmission revenue requirement is allocated to service categories based on a distance-weighted forecast of throughput. The transmission revenue requirement for each service category is further divided between the primary and secondary services. The transmission revenue requirement for each primary service divided by its forecasted contract demand quantity and added to the metering charge establishes the primary service rate for the year.

Table 5.1-1 lists the service categories, and primary and secondary services.

Table 5.1-1
Service Categories and their Associated Services

Service Category	Primary Service	Secondary Service
Receipt	FT-R	FT-RN; IT-R; FT-P
Export Delivery	FT-D	FT-DW; STFT; IT-D
Intra-Alberta Delivery	FT-A	FT-P; FCS

With the exception of FCS, the rate for the secondary services is a direct function of the rate for its primary service (e.g., FT-DW, STFT and IT-D rates are 175%, at least 135%, and 110%, respectively, of the FT-D rate). The FCS is related to the FT-A service as an FCS contract is required at an Alberta delivery station before FT-A service can be provided as the FT-A remains a commodity service. The FCS revenue is facility specific.

The transmission revenue requirement is allocated to each service category based on that service category's share of the total distance-weighted volume forecast of throughput. The historic volume-weighted DOH is used to forecast distances and provides a measure of the transmission system actually used in transporting one unit of gas for each service category. By multiplying the DOH by the forecasted throughput for the service category a measure of the transmission system actually used to transport the entire service category is obtained. Dividing each service category's volume x distance by the volume x distance for all service categories calculates that service category's share of the total transmission costs and thus its share of the transmission revenue requirement. Table 5.1-2 provides an illustrative example to demonstrate this concept.

Table 5.1-2
Calculation of Service Category Share of Transmission Revenue Requirement

Service Category	DOH (km)	Forecasted Throughput (10^6m^3/Year)	Volume x distance (DOH x Forecasted Throughput)	Volume x distance Index (Volume x distance/ ∑ Volume x distance)
Receipt	517	100,011	51,705,513	52%
Export Delivery	559	84,229	47,083,949	47%
Intra-Alberta Delivery*	124	10,557	1,309,063	1%
Total			100,098,524	100%

Note:
* Does not include extraction and storage volumes.

In this example the receipt service category would be allocated 52% of the transmission revenue requirement. The historical distance for receipt services was 517 km and the forecasted throughput is 100,011 10^6m^3/Year. Therefore, the receipt volume x distance is 51,705,513 (517 x 100,011) and its share of the total volume x distance for all service categories (100,098,524) is 52% (51,705,513 / 100,098,524).

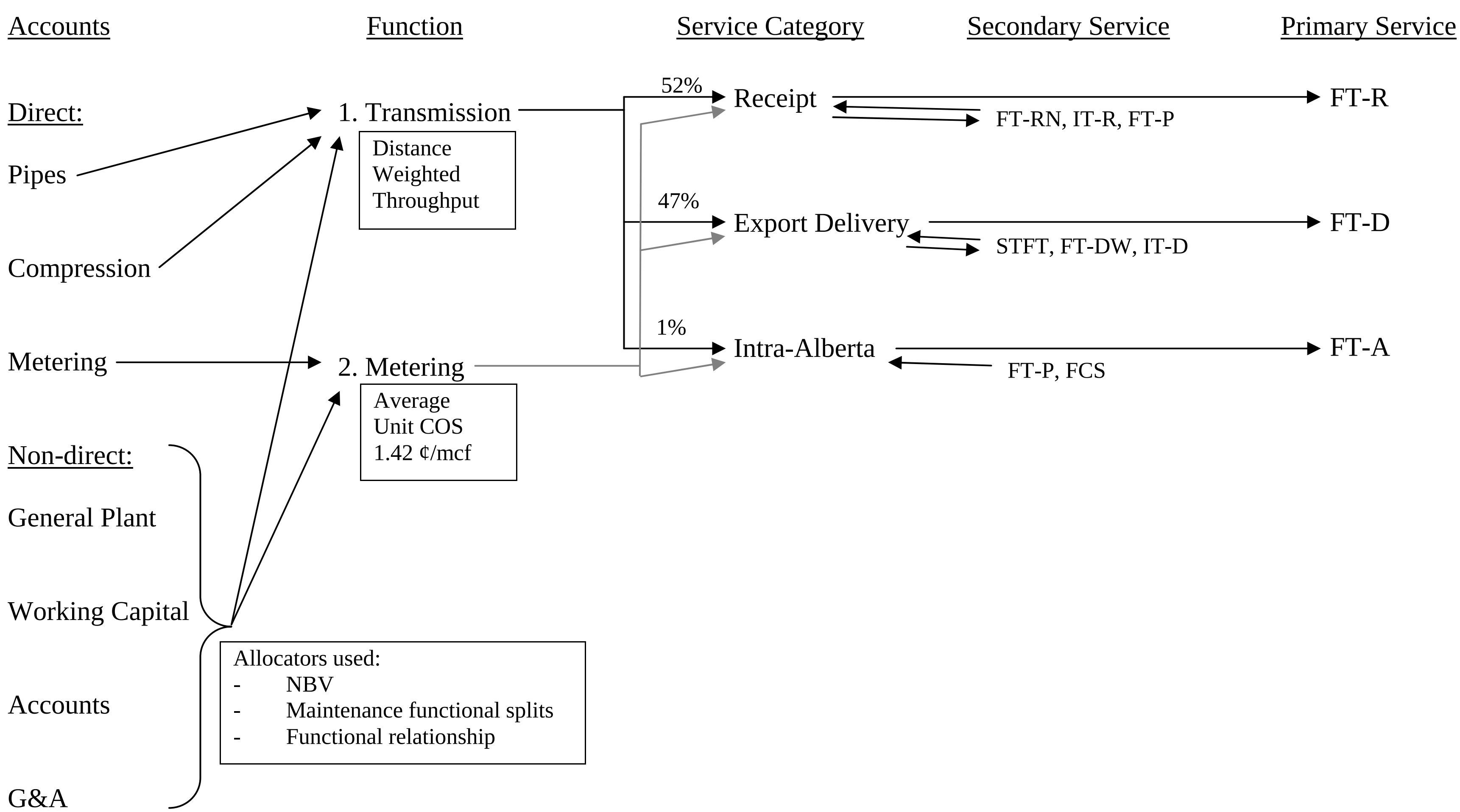
Diagram 5.1-1 shows a pictorial representation of the actual allocations for each service category.

The revenue generated by the secondary services is subtracted from the transmission revenue requirement of each service category. This is an iterative process because the revenue generated by the secondary services is calculated by using the secondary services' rates, which are dependant on the corresponding primary service rate.

Subtracting the secondary service revenue requirement from each service category transmission revenue requirement leaves the transmission revenue requirement for each primary service. The primary service transmission revenue requirement divided by its respective forecast of contract demand and added to the metering charge produces the primary service rate for the year.

Diagram 5.1-1

Application of Cost Allocations to Rates Determination



5.2 ALLOCATION OF REVENUE REQUIREMENT TO ALL TARIFF SERVICES

Diagram 5.2-1 details all the steps required to allocate the total revenue requirement for the test year to all tariff services. In order to gain a fuller understanding of the allocation process, each box on the diagram is explained below. Table 5.2-1 provides the forecasted costs, volumes and rates for all services for the test year.

5.2.1 Box 1 – Total Revenue Requirement

This is the revenue requirement for the test year.

5.2.2 Oval 1 – COS for Metering Facilities

This is the COS for metering facilities as determined by the base year COS Study.

5.2.3 Box 2 – Total Service Volume

This is the total metered volumes for all services for the base year.

5.2.4 Box 3 – Metering Charge

This is the system average metering charge which is included in the rates for all services except FT-X and IT-S. It is determined by dividing the COS for metering facilities (Oval 1) by total service volumes (Box 2).

5.2.5 Box 4 – Primary Service Volume

This is the forecasted volumes for all primary services for the test year.

5.2.6 Box 5 – Primary Service Metering Revenue

This is the result of multiplying the metering charge (Box 3) by the primary service volume (Box 4).

5.2.7 Box 6 – Other Service Revenue

This is the revenue that is collected from services other than those in the primary service categories of Receipt, Delivery, and Intra-Alberta Delivery.

OS and PT revenues are based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2, and LRS-3 services are calculated based on EUB approved rates and forecasted volumes.

5.2.8 Box 7 – Total Service Category Transmission Revenue Requirement

This is the transmission revenue requirement that needs to be allocated among the various service categories. It is determined by subtracting the other service revenue (Box 6) and primary service metering revenue (Box 5) from the total revenue requirement (Box 1).

5.2.9 Box 8 – Service Categories

This is the step where the cost allocation methodology is used to allocate the transmission revenue requirement to each primary service (FT-R, FT-D and FT-A). The transmission revenue requirement is allocated based on each service category's share of the total distance-weighted volume forecast of throughput. The historic volume-weighted DOH is used to forecast distances and provides a measure of the transmission system actually used in transporting one unit of gas for each service category. By multiplying the DOH by the forecasted throughput for the service category, a measure of the transmission system actually used to transport the entire service category is obtained.

Dividing each service category's volume x distance by the volume x distance for all service categories calculates that service category's share of the total transmission costs and thus its share of the transmission revenue requirement. The resulting ratio is called the volume x distance index.

The forecasted throughput quantities do not include FT-R used to provide fuel or LRS-1, LRS-2, LRS-3, or FT-P volumes. The forecasted FT-A throughput does not include volumes for extraction, taps or storage.

5.2.10 Box 9 – Transmission Revenue Requirement by Service Category

This is the transmission revenue requirement allocated to each service category. It is calculated by multiplying the volume x distance index of each service category (Box 8) by the total service category transmission revenue requirement (Box 7).

5.2.11 Box 10 – Transmission Revenue Requirement by Individual Service

The estimated revenue (both metering and transmission) for each secondary service subtracted from the corresponding service category transmission revenue leaves the transmission revenue requirement applicable for each primary service. The FT-P revenue is subtracted from both the receipt service category and the intra-Alberta delivery service category as FT-P provides both receipt and intra-Alberta delivery service.

Revenues from FT-P service are based on the different distance bands which apply for each FT-P contract and the forecasted volumes for each contract. The rates for the distance bands are a function of the average FT-R transmission rate. Revenues from FT-RN and IT-R services are based on premiums to the total FT-R rate and forecasted volumes for each of these services. Revenues from FT-DW, STFT and IT-D are based on premiums to the total FT-D rate and the forecasted volumes for each of these services. Therefore, the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D.

5.2.12 Box 11 – Contract Demand by Service

This is the forecasted contract demand by primary service for the test year. For FT-A the contract demand is actually the FT-A throughput.

5.2.13 Box 12 – Transmission Component of the Average FT-R Rate

The transmission component of the average FT-R rate is determined by dividing the FT-R transmission revenue (Box 10) by the FT-R contract demand (Box 11).

5.2.14 Box 13 – Transmission Component by Service

The transmission component of each service rate is calculated by dividing the transmission revenue requirement for that service (Box 10) by its forecasted contract demand quantity (Box 11).

5.2.15 Box 14 – Metering Charge

This is the metering charge from Box 3.

5.2.16 Box 15 – The Average FT-R Rate

The average FT-R rate is determined by adding the transmission component of the average FT-R rate (Box 12) and the metering charge (Box 14).

5.2.17 Box 16 – Receipt Point Allocation

This is the distance-diameter algorithm or allocation methodology used to determine the individual receipt point prices. Each receipt point’s price is determined by that receipt point’s share of the total volume-weighted distance diameter allocation units. Individual receipt point prices will vary within a floor and ceiling band of ±8 cents/Mcf from the average FT-R rate (Box15).

5.2.18 Box 17 – Receipt Specific FT-R Rates

Based on the receipt point allocation (Box 16), each receipt point rate is determined.

5.2.19 Box 18 – Rates by Service

The rate for each service is determined by adding the transmission component for that service (Box 13) and the metering charge (Box 14).

Diagram 5.2-1 – Illustrative Rate Calculation

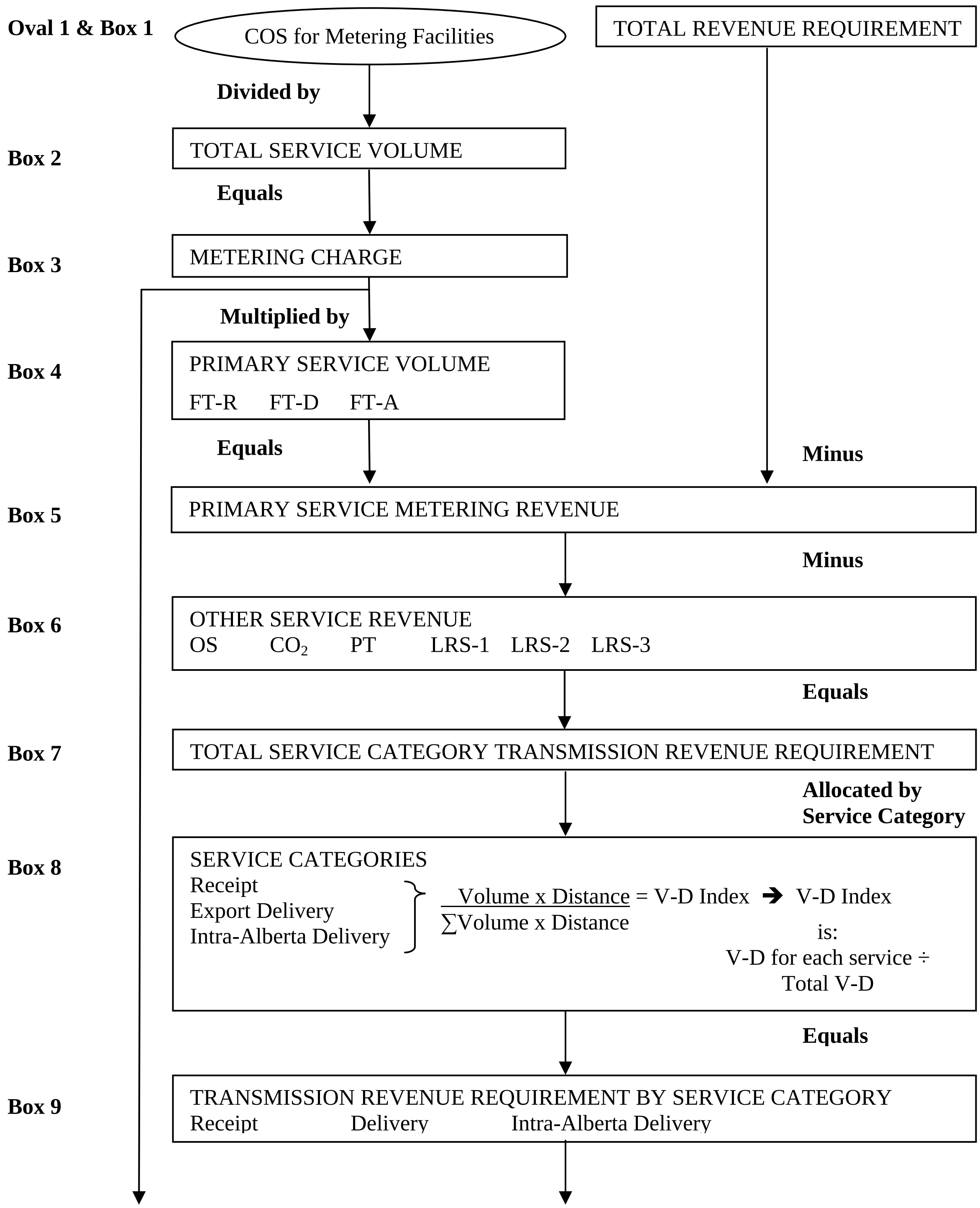


Diagram 5.2-1 – Illustrative Rate Calculation (cont…)

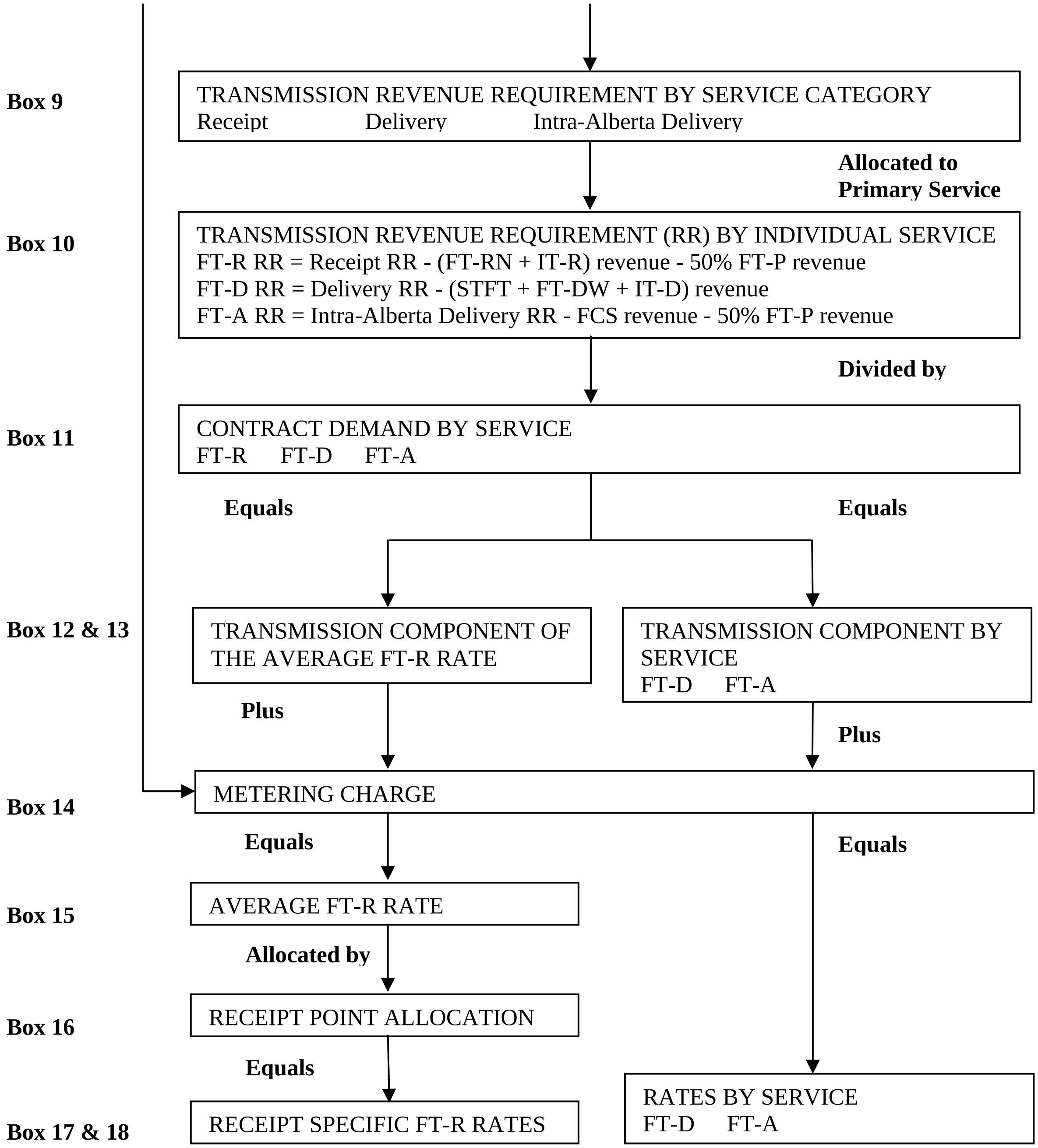


Table 5.2-1 – Allocation of 2005 Revenue Requirement to Services

Service Category	**Service**	**Revenue ($Millions)**	**Forecast Volume (10^6m^3)**	**Rates ($/10^3m^3$)**
Receipt	FT-R[1]	429.6	82,271	158.83
Receipt	FT-RN[2]	5.0	696	219.85
Receipt	IT-R[2]	118.1	21,306	5.54
Export	FT-D	442.5	75,640	177.94
Export	STFT[2]	-	-	-
Export	FT-DW[2]	-	-	-
Export	IT-D[5]	69.0	10,715	6.44
Intra-Alberta	FT-A	5.0	10,557	0.47
Intra-Alberta	FCS	4.9	n/a	n/a
Intra-Alberta	FT-P[2]	21.0	3,916	163.01
Extraction	FT-X	-	4,370	-
Storage	IT-S	-	38,356	-
Other	LRS[2]	43.3	6,733	195.87
Other	LRS-2[3]	0.7	381	50,000/month
Other	LRS-3[3]	3.3	515	192.37
Other	CO_2[2]	15.4	n/a	n/a
Other	PT[4]	0.9	n/a	n/a
Other	Other Service	1.1	n/a	n/a
	Total	**1,160.0**		

Notes:
1. Rate quoted is a volume-weighted average for a three-year contract term.
2. Rate quoted is volume-weighted average.
3. Revenue quoted includes NGTL shareholder contribution.
4. New service only forecasted in 2005.
5. Forecast quantity is net of Alternate Access.

6.0 COST ALLOCATION METHODOLOGY FOR ALTERNATIVE 5

6.1 OVERVIEW

This methodology is similar to the existing methodology as a system average metering charge is included in each service rate. Revenue for the metering charge is deducted from the test year's revenue requirement, which yields a transmission revenue requirement. The test year's transmission revenue requirement is allocated to service categories based on a distance-weighted forecast of throughput. The transmission revenue requirement for each service category is further divided between the primary and secondary services. The transmission revenue requirement for each primary service divided by its forecasted contract demand quantity and added to the metering charge establishes the primary service rate for the year.

Table 6.1-1 lists the service categories, and primary and secondary services.

Table 6.1-1
Service Categories and their Associated Services

Service Category	Primary Service	Secondary Service
Receipt	FT-R	FT-RN; IT-R
Export Delivery	FT-D	FT-DW; STFT; IT-D
Intra-Alberta Delivery	FT-P	

Primary services for this methodology are FT-R, FT-D and FT-P. This alternative has no FT-A service so all intra-Alberta deliveries must utilize FT-P service. As FT-P is a firm demand service there is no need for additional accountability under FCS so this service is also eliminated.

The rate for the secondary services is a direct function of the rate for its primary service (e.g., FT-DW, STFT and IT-D rates are 175%, at least 135%, and 110%, respectively, of the FT-D rate).

The transmission revenue requirement is allocated to each service category based on that service category's share of the total distance-weighted volume forecast of throughput. The historic volume-weighted DOH is used to forecast distances and provides a measure of the transmission system actually used in transporting one unit of gas for each service category. By multiplying the DOH by the forecasted throughput for the service category, a measure of the transmission system actually used to transport the entire service category is obtained. Dividing each service category's volume x distance by the volume x distance for all service categories calculates that service category's share of the total transmission costs and thus its share of the transmission revenue requirement. Table 6.1-2 provides an illustrative example to demonstrate this concept.

Table 6.1-2
Calculation of Service Category Share of Revenue Requirement

Service Category	DOH (km)	Forecasted Throughput ($10^6 m^3$/Year)	Volume x distance (DOH x Forecasted Throughput)	Volume x distance Index (Volume x distance/ ∑ Volume x distance)
Receipt	517	100,011	51,705,513	51%
Export Delivery	559	84,229	47,083,949	47%
Intra-Alberta Points to Point	124	14,473	1,794,639	2%
Total			100,584,100	100%

In this example the receipt service category would be allocated 51% of the transmission revenue requirement. The historical distance for receipt services was 517 km and the forecasted throughput is 100,011 $10^6 m^3$/Year. Therefore, the receipt volume x distance is 51,705,513 (517 x 100,011) and its share of the total volume x distance for all service categories (100,584,100) is 51% (51,705,513 / 100,584,100).

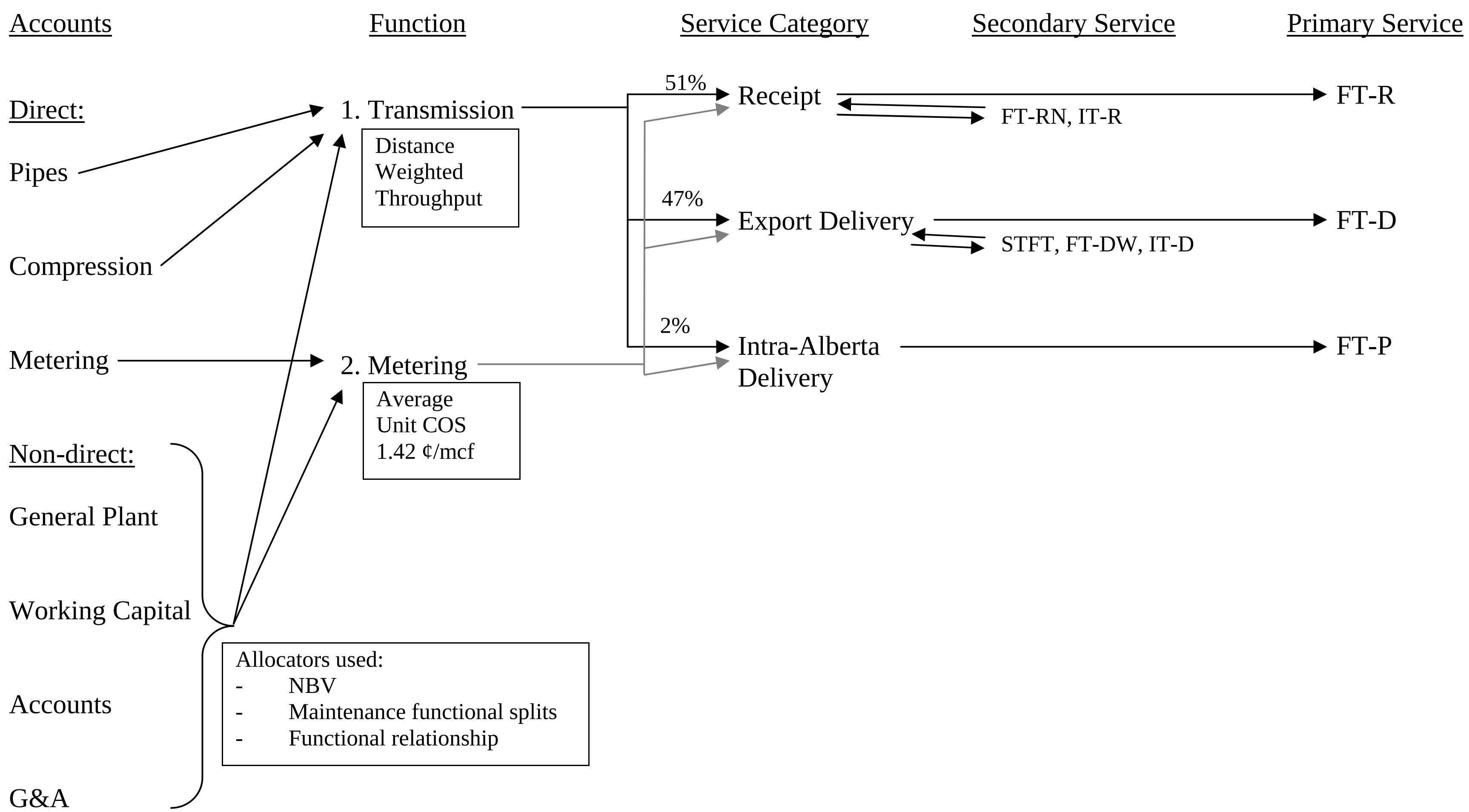
Diagram 6.1-1 shows a pictorial representation of the actual allocations for each service category.

The revenue generated by the secondary services is subtracted from the transmission revenue requirement of each service category. This is an iterative process because the revenue generated by the secondary services is calculated by using the secondary services' rates, which are dependant on the corresponding primary service rate.

Subtracting the secondary service revenue requirement from each service category transmission revenue requirement leaves the transmission revenue requirement for each primary service. The primary service transmission revenue requirement divided by its respective forecast of contract demand and added to the metering charge produces the primary service rate for the year.

Diagram 6.1-1

Application of Cost Allocations to Rates Determination



6.2 ALLOCATION OF REVENUE REQUIREMENT TO ALL TARIFF SERVICES

Diagram 6.2-1 details all the steps required to allocate the total revenue requirement for the test year to all tariff services. In order to gain a fuller understanding of the allocation process, each box on the diagram is explained below. Table 6.2-1 provides the forecasted costs, volumes and rates for all services for the test year.

6.2.1 Box 1 – Total Revenue Requirement

This is the revenue requirement for the test year.

6.2.2 Oval 1 – COS for Metering Facilities

This is the COS for metering facilities as determined by the base year COS Study.

6.2.3 Box 2 – Total Service Volume

This is the total metered volumes for all services for the base year.

6.2.4 Box 3 – Metering Charge

This is the system average metering charge which is included in the rates for all services except FT-X and IT-S. It is determined by dividing the COS for metering facilities (Oval 1) by total service volumes (Box 2).

6.2.5 Box 4 – Primary Service Volume

This is the forecasted volumes for all primary services for the test year.

6.2.6 Box 5 – Primary Service Metering Revenue

This is the result of multiplying the metering charge (Box 3) by the primary service volume (Box 4).

6.2.7 Box 6 – Other Service Revenue

This is the revenue that is collected from services other than those in the primary service categories of Receipt, Delivery, and Intra-Alberta Delivery.

OS and PT revenues are based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2, and LRS-3 services are calculated based on EUB approved rates and forecasted volumes.

6.2.8 Box 7 – Total Service Category Transmission Revenue Requirement

This is the transmission revenue requirement that needs to be allocated among the various service categories. It is determined by subtracting the other service revenue (Box 6) and primary service metering revenue (Box 5) from the total revenue requirement (Box 1).

6.2.9 Box 8 – Service Categories

This is the step where the cost allocation methodology is used to allocate the transmission revenue requirement to each primary service (FT-R, FT-D and FT-P). The transmission revenue requirement is allocated based on each service category’s share of the total distance-weighted volume forecast of throughput. The historic volume-weighted DOH is used to forecast distances and provides a measure of the transmission system actually used in transporting one unit of gas for each service category. By multiplying the DOH by the forecasted throughput for the service category, a measure of the transmission system actually used to transport the entire service category is obtained.

Dividing each service category’s volume x distance by the volume x distance for all service categories calculates that service category’s share of the total transmission costs and thus its share of the transmission revenue requirement. The resulting ratio is called the volume x distance index.

The forecasted throughput quantities do not include FT-R used to provide fuel or LRS-1, LRS-2 or LRS-3 volumes. The forecasted FT-P throughput does not include volumes for extraction, taps or storage.

6.2.10 Box 9 – Transmission Revenue Requirement by Service Category

This is the transmission revenue requirement allocated to each service category. It is calculated by multiplying the volume x distance index of each service category (Box 8) by the total service category transmission revenue requirement (Box 7).

6.2.11 Box 10 – Transmission Revenue Requirement by Individual Service

The estimated revenue (both metering and transmission) for each secondary service subtracted from the corresponding service category transmission revenue leaves the transmission revenue requirement applicable for each primary service.

Revenues from FT-RN and IT-R services are based on premiums to the FT-R rate and forecasted volumes for each of these services. Revenues from FT-DW, STFT and IT-D are based on premiums to the FT-D rate and the forecasted volumes for each of these services. Therefore, the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D.

6.2.12 Box 11 – Contract Demand by Service

This is the forecasted contract demand by primary service for the test year. The FT-P contract demand is estimated by adding the current FT-P contract demand forecast and the current FT-A throughput forecast adjusted to have a contract utilization rate of 75%.

6.2.13 Box 12 – Transmission Component of the Average FT-R Rate

The transmission component of the average FT-R rate is determined by dividing the FT-R transmission revenue (Box 10) by the FT-R contract demand (Box 11).

6.2.14 Box 13 – Transmission Component by Service

The transmission component of each service rate is calculated by dividing the transmission revenue requirement for that service (Box 10) by its forecasted contract demand quantity (Box 11).

6.2.15 Box 14 – Metering Charge

This is the metering charge from Box 3.

6.2.16 Box 15 – Average FT-R Rate

The average FT-R rate is determined by adding the transmission component of the average FT-R rate (Box 12) and the metering charge (Box 14).

6.2.17 Box 16 – Receipt Point Allocation

This is the distance-diameter algorithm or allocation methodology used to determine the individual receipt point prices. Each receipt point's price is determined by that receipt point's share of the total volume-weighted distance diameter allocation units. Individual receipt point prices will vary within a floor and ceiling band of ±8 cents/Mcf from the average FT-R rate (Box15).

6.2.18 Box 17 – Receipt Specific FT-R Rates

Based on the receipt point allocation (Box 16), each receipt point rate is determined.

6.2.19 Box 18 – Rates by Service

The rate for each service is determined by adding the transmission component for that service (Box 13) and the metering charge (Box 14).

Diagram 6.2-1 – Illustrative Rate Calculation

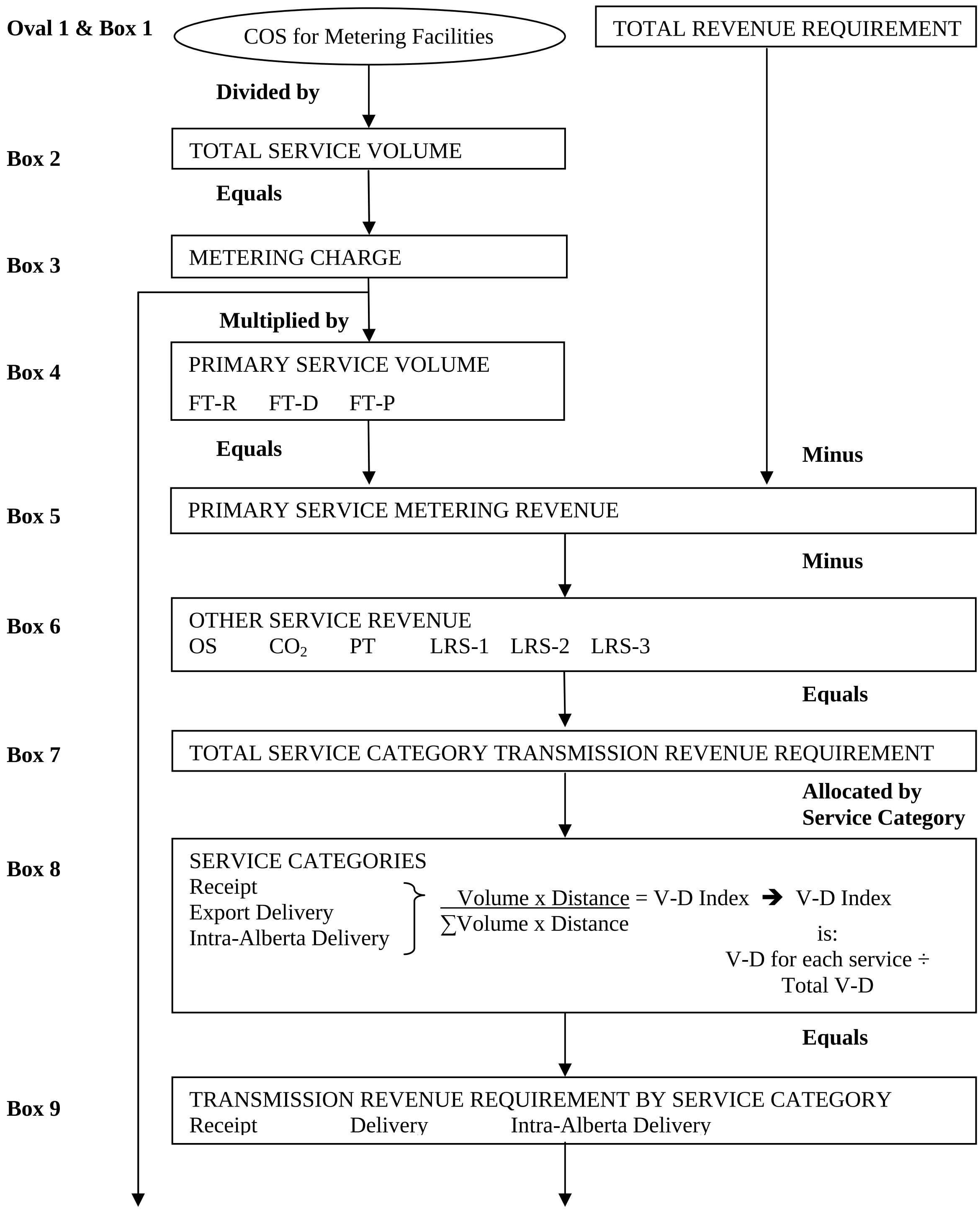


Diagram 6.2-1 – Illustrative Rate Calculation (cont…)

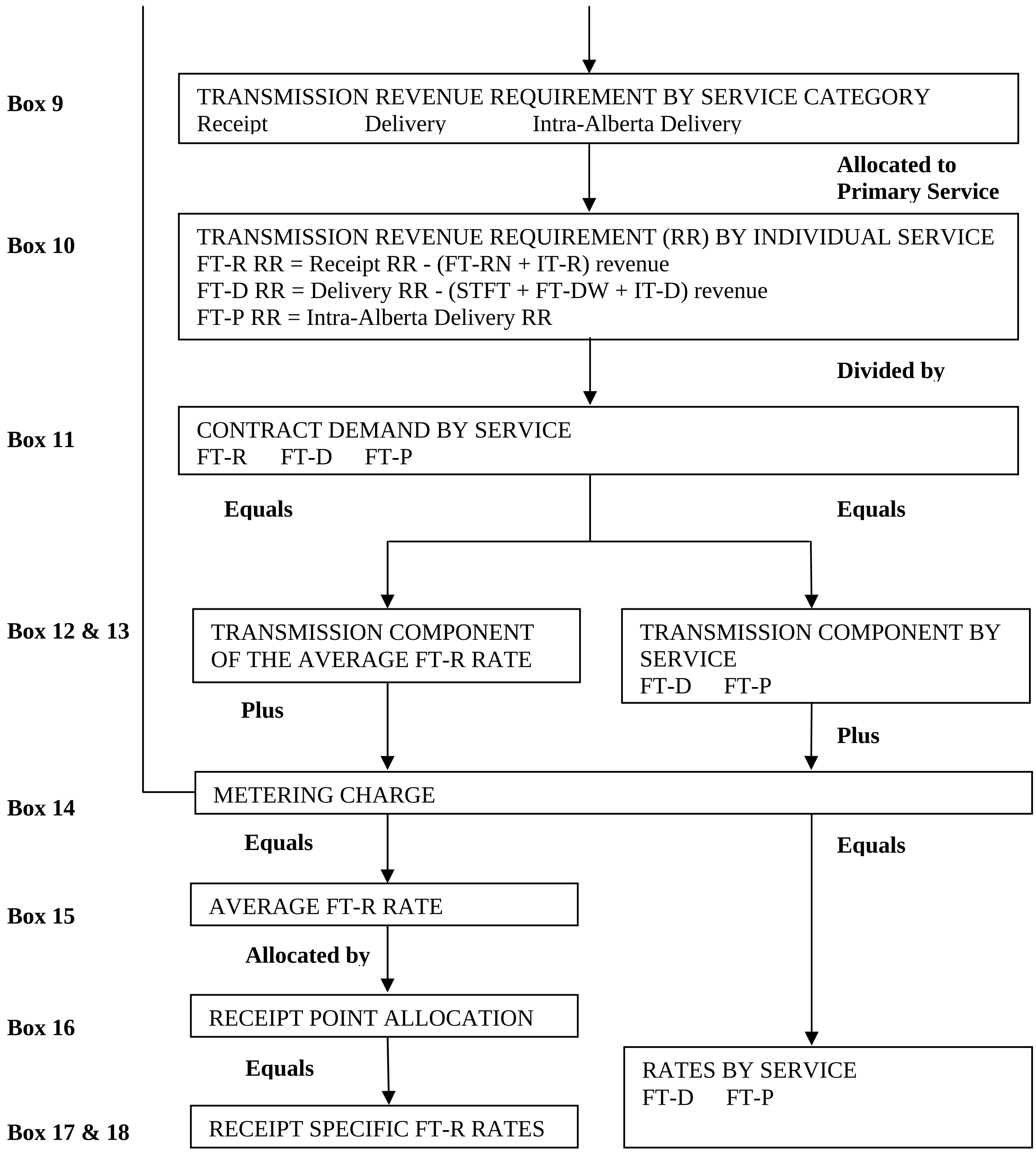


Table 6.2-1 – Allocation of 2005 Revenue Requirement to Services

Service Category	Service	Revenue ($Millions)	Forecast Volume (10^6m^3)	Rates ($/$10^3m^3$)
Receipt	FT-R[1]	430.8	82,271	159.24
Receipt	FT-RN[2]	5.0	696	220.30
Receipt	IT-R[2]	118.4	21,306	5.56
Export	FT-D	437.02	75,640	175.74
Export	STFT[2]	-	-	-
Export	FT-DW[2]	-	-	-
Export	IT-D[5]	68.0	10,715	6.35
Intra-Alberta	FT-P[2]	35.9	17,992	60.55
Extraction	FT-X	-	155	-
Storage	IT-S	-	38,356	-
Other	LRS[2]	43.3	6,733	195.87
Other	LRS-2[3]	0.7	381	50,000/month
Other	LRS-3[3]	3.3	515	192.37
Other	CO_2[2]	15.4	n/a	n/a
Other	PT[4]	0.9	n/a	n/a
Other	Other Service	1.1	n/a	n/a
	Total	**1,160.0**		

Notes:
1. Rate quoted is a volume-weighted average for a three-year contract term.
2. Rate quoted is volume-weighted average.
3. Revenue quoted includes NGTL shareholder contribution.
4. New service only forecasted in 2005.
5. Forecast quantity is net of Alternate Access.

7.0 COST ALLOCATION METHODOLOGY FOR ALTERNATIVE 6

7.1 OVERVIEW

This methodology is similar to the existing methodology as a system average metering charge is included in each service rate. Revenue for the metering charge is deducted from the test year's revenue requirement, which yields a transmission revenue requirement. The test year's transmission revenue requirement is allocated to service categories based on a distance-weighted forecast of throughput. The transmission revenue requirement for each service category is further divided between the primary and secondary services. The transmission revenue requirement for each primary service divided by its forecasted contract demand quantity and added to the metering charge establishes the primary service rate for the year.

Table 7.1-1 lists the service categories, and primary and secondary services.

Table 7.1-1
Service Categories and their Associated Services

Service Category	Primary Service	Secondary Service
Receipt	FT-R	FT-RN; IT-R
Export Delivery	FT-D	FT-DW; STFT; IT-D
Intra-Alberta Delivery	FT-A	FCS
Intra-Alberta Points to Point	FT-P	
Extraction Access	FT-X	
Storage Access	IT-S	

With the exception of FCS, the rate for the secondary services is a direct function of the rate for its primary service (e.g., FT-DW, STFT and IT-D rates are 175%, at least 135%, and 110%, respectively, of the FT-D rate). The FCS is related to the FT-A service as an FCS contract is required at an Alberta delivery station before FT-A service can be provided. The FCS revenue is facility specific.

The transmission revenue requirement is allocated to each service category based on that service category's share of the total distance-weighted volume forecast of throughput. The historic volume-weighted DOH is used to forecast distances and provides a measure of the transmission system actually used in transporting one unit of gas for each service category. By multiplying the DOH by the forecasted throughput for the service category a measure of the transmission system actually used to transport the entire service category is obtained. Dividing each service category's volume x distance by the volume x distance for all service categories calculates that service category's share of the total transmission costs and thus its share of the revenue requirement. Table 7.1-2 provides an illustrative example to demonstrate this concept.

Table 7.1-2
Calculation of Service Category Share of Revenue Requirement

Service Category	DOH (km)	Forecasted Throughput ($10^6 m^3$/Year)	Volume x distance (DOH x Forecasted Throughput)	Volume x distance Index (Volume x distance/ ∑ Volume x distance)
Receipt	517	100,011	51,705,513	49%
Export Delivery	559	84,229	47,083,949	45%
Intra-Alberta Delivery	124	10,557	1,309,063	1%
Intra-Alberta Points to Point	124	3,915	485,576	<1%
Extraction Access	511	4,371	2,233,324	2%
Storage Access	236	10,548	2,489,328	2%
Total			105,396,819	100%

In this example the receipt service category would be allocated 49% of the transmission revenue requirement. The historical distance for receipt services was 517 km and the forecasted throughput is 100,011 $10^6 m^3$/Year. Therefore, the receipt volume x distance is 51,705,513 (517 x 100,011) and its share of the total volume x distance for all service categories (105,396,819) is 49% (51,705,513 / 105,396,819).

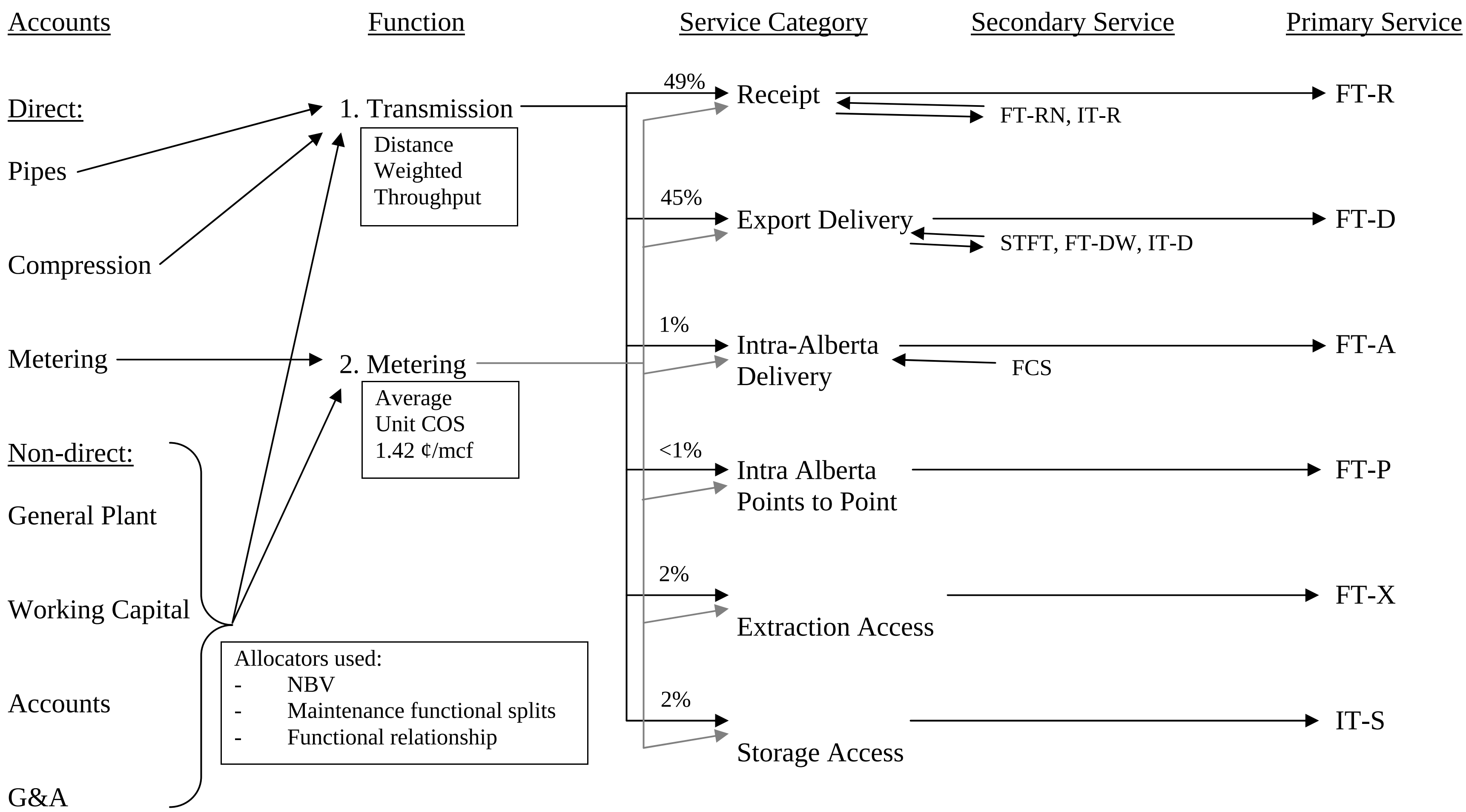
Diagram 7.1-1 shows a pictorial representation of the actual allocations for each service category.

The revenue generated by the secondary services is subtracted from the transmission revenue requirement of each service category. This is an iterative process because the revenue generated by the secondary services is calculated by using the secondary services' rates, which are dependant on the corresponding primary service rate.

Subtracting the secondary service revenue requirement from each service category transmission revenue requirement leaves the transmission revenue requirement for each primary service. The primary service transmission revenue requirement divided by its respective forecast of contract demand and added to the metering charge produces the primary service rate for the year.

Diagram 7.1-1

Application of Cost Allocations to Rates Determination



7.2 ALLOCATION OF REVENUE REQUIREMENT TO ALL TARIFF SERVICES

Diagram 7.2-1 details all the steps required to allocate the total revenue requirement for the test year to all tariff services. In order to gain a fuller understanding of the allocation process, each box on the diagram is explained below. Table 7.2-1 provides the forecasted costs, volumes and rates for all services for the test year.

7.2.1 Box 1 – Total Revenue Requirement

This is the revenue requirement for the test year.

7.2.2 Oval 1 – COS for Metering Facilities

This is the COS for metering facilities as determined by the base year COS Study.

7.2.3 Box 2 – Total Service Volume

This is the total metered volumes for all services for the base year.

7.2.4 Box 3 – Metering Charge

This is the system average metering charge which is included in the rates for all services including FT-X and IT-S. It is determined by dividing the COS for Metering Facilities (Oval 1) by Total Service Volumes (Box 2).

7.2.5 Box 4 – Primary Service Volume

This is the forecasted volumes for all primary services for the test year.

7.2.6 Box 5 – Primary Service Metering Revenue

This is the result of multiplying the metering charge (Box 3) by the primary service volume (Box 4).

7.2.7 Box 6 – Other Service Revenue

This is the revenue that is collected from services other than those in the primary service categories of Receipt, Delivery, Intra-Alberta Delivery (FT-A), Intra-Alberta Delivery (FT-P), Extraction Access, and Storage Access.

OS and PT revenues are based on the costs of providing these services. CO_2 revenue is based on the estimated cost of providing CO_2 extraction. Revenues from LRS-1, LRS-2, and LRS-3 services are calculated based on EUB approved rates and forecasted volumes.

7.2.8 Box 7 – Total Service Category Transmission Revenue Requirement

This is the transmission revenue requirement that needs to be allocated among the various service categories. It is determined by subtracting the other service revenue (Box 6) and primary service metering revenue (Box 5) from the total revenue requirement (Box 1).

7.2.9 Box 8 – Service Categories

This is the step where the cost allocation methodology is used to allocate the transmission revenue requirement to each primary service (FT-R, FT-D, FT-A, FT-P, FT-X and IT-S). The transmission revenue requirement is allocated based on each service category's share of the total distance weighted volume forecast of throughput. The historic volume-weighted DOH is used to forecast distances and provides a measure of the transmission system actually used in transporting one unit of gas for each service category. By multiplying the DOH by the forecasted throughput for the service category, a measure of the transmission system actually used to transport the entire service category is obtained.

Dividing each service category's volume x distance by the volume x distance for all service categories calculates that service category's share of the total transmission costs and thus its share of the transmission revenue requirement. The resulting ratio is called the volume x distance index.

The forecasted throughput quantities do not include FT-R used to provide fuel or LRS-1, LRS-2, or LRS-3 volumes. The forecasted FT-A throughput does not include volumes for extraction, taps or storage. Extraction and storage forecasts are included in their respective service categories. The actual 2003 storage volumes have been used as an estimate of the 2005 forecast volumes. The distance of haul for storage is calculated in a similar manner as the distances for intra-Alberta, export and extraction deliveries (i.e. it is the 2003 DOH from receipt stations to the Storage Delivery Points).

7.2.10 Box 9 – Transmission Revenue Requirement by Service Category

This is the transmission revenue requirement allocated to each service category. It is calculated by multiplying the volume x distance index of each service category (Box 8) by the total service category transmission revenue requirement (Box 7).

7.2.11 Box 10 – Transmission Revenue Requirement by Individual Service

The estimated revenue (both metering and transmission) for each secondary service subtracted from the corresponding service category transmission revenue leaves the transmission revenue requirement applicable for each primary service.

Revenues from FT-RN and IT-R services are based on premiums to the FT-R rate and forecasted volumes for each of these services. Revenues from FT-DW, STFT and IT-D are based on premiums to the FT-D rate and the forecasted volumes for each of these services. Therefore, the process of determining the revenues to be received from these services is an iterative one based on their relationship to either FT-R or FT-D.

7.2.12 Box 11 – Contract Demand by Service

This is the forecasted contract demand by primary service for the test year. For FT-A the contract demand is actually the FT-A throughput. For most services, the contract demand is very close to the forecasted throughput. The one exception is IT-S. The service category revenue for storage access is based on the estimated physical gas that will be delivered to the various storage facilities. Historically the quantity of gas commercially requested to be delivered to a storage facility via IT-S is 3.6 times greater than the quantity physically delivered to the various storage facilities. Therefore, the contract demand for IT-S is calculated by multiplying the forecasted physical storage deliveries by this factor.

7.2.13 Box 12 – Transmission Component of the Average FT-R Rate

The transmission component of the average FT-R rate is determined by dividing the FT-R transmission revenue (Box 10) by the FT-R contract demand (Box 11).

7.2.14 Box 13 – Transmission Component by Service

The transmission component of each service rate is calculated by dividing the transmission revenue requirement for that service (Box 10) by its forecasted contract demand quantity (Box 11).

7.2.15 Box 14 – Metering Charge

This is the metering charge from Box 3.

7.2.16 Box 15 – Average FT-R Rate

The average FT-R rate is determined by adding the transmission component of the average FT-R rate (Box 12) and the metering charge (Box 14).

7.2.17 Box 16 – Receipt Point Allocation

This is the distance-diameter algorithm or allocation methodology used to determine the individual receipt point prices. Each receipt point's price is determined by that receipt point's share of the total volume-weighted distance diameter allocation units. Individual receipt point prices will vary within a floor and ceiling band of ±8 cents/Mcf from the average FT-R rate (Box15).

7.2.18 Box 17 – Receipt Specific FT-R Rates

Based on the receipt point allocation (Box 16), each receipt point rate is determined.

7.2.19 Box 18 – Rates by Service

The rate for each service is determined by adding the transmission component for that service (Box 13) and the metering charge (Box 14).

Diagram 7.2-1 – Illustrative Rate Calculation

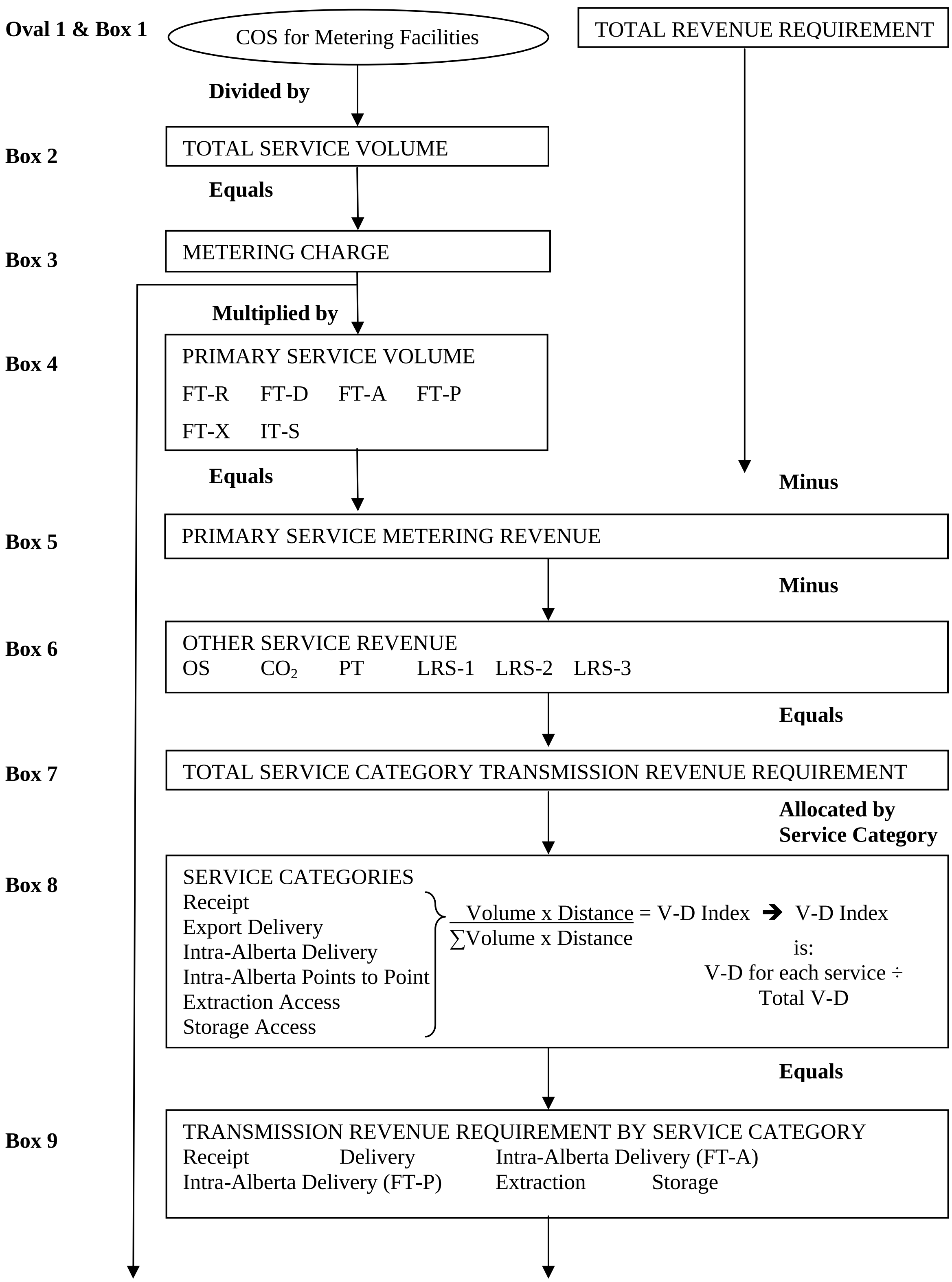


Diagram 7.2-1 – Illustrative Rate Calculation (cont…)

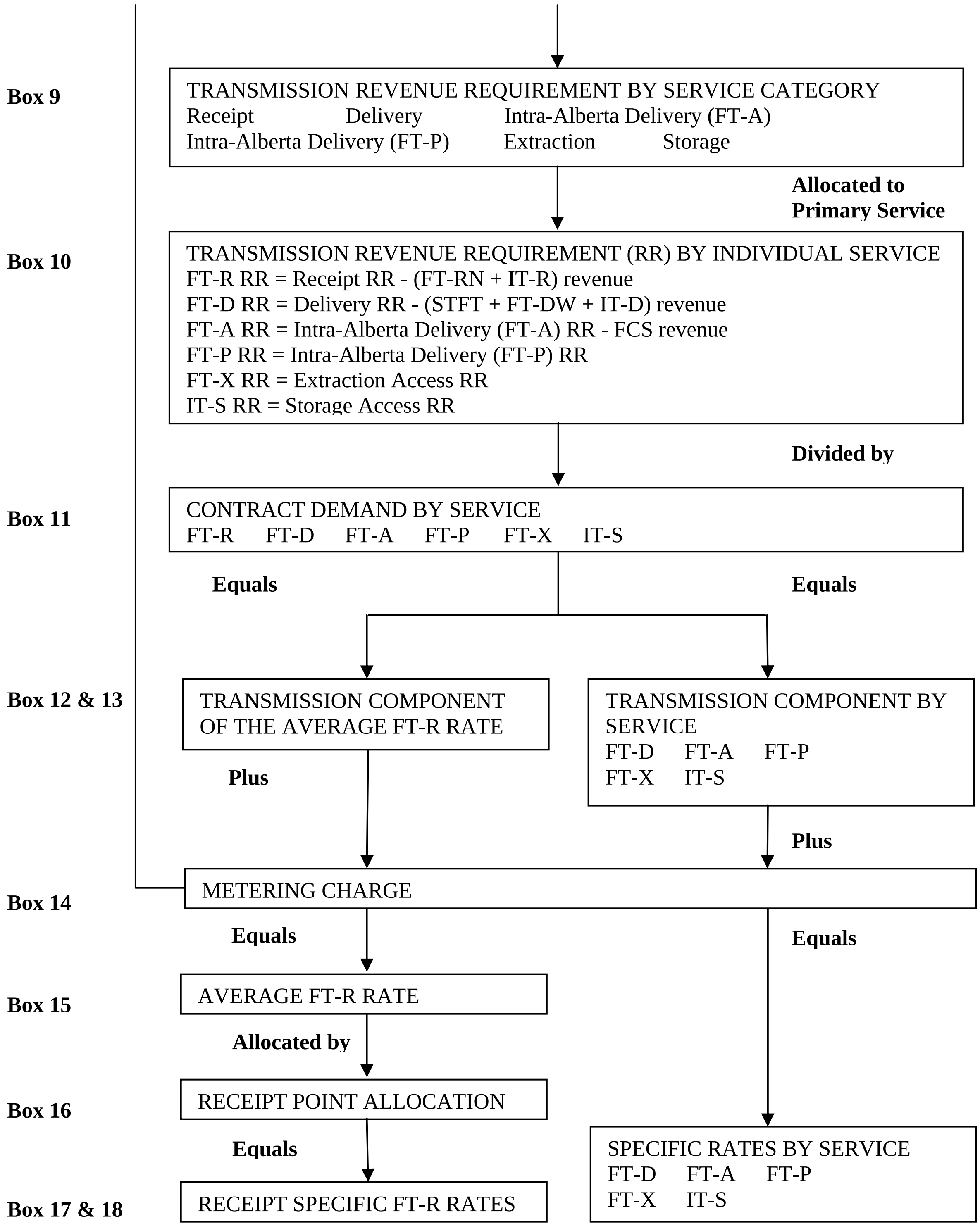


Table 7.2-1 – Allocation of 2005 Revenue Requirement to Services

Service Category	Service	Revenue ($Millions)	Forecast Volume (10^6m^3)	Rates ($/$10^3m^3$)
Receipt	FT-R[1]	408.0	82,271	150.84
Receipt	FT-RN[2]	4.8	696	211.08
Receipt	IT-R[2]	112.2	21,306	5.26
Export	FT-D	414.0	75,640	166.46
Export	STFT[2]	-	-	-
Export	FT-DW[2]	-	-	-
Export	IT-D[5]	64.5	10,715	6.02
Intra-Alberta	FT-A	12.6	10,557	1.19
Intra-Alberta	FCS	4.9	n/a	n/a
Intra-Alberta	FT-P[2]	8.5	3,916	65.74
Extraction	FT-X	23.1	4,370.0	5.28
Storage	IT-S	42.6	38,356	1.11
Other	LRS[2]	43.3	6,733	195.87
Other	LRS-2[3]	0.7	381	50,000/month
Other	LRS-3[3]	3.3	515	192.37
Other	CO_2[2]	15.4	n/a	n/a
Other	PT[4]	0.9	n/a	n/a
Other	Other Service	1.1	n/a	n/a
	Total	**1,160.0**		

Notes:
1. Rate quoted is a volume-weighted average for a three-year contract term.
2. Rate quoted is volume-weighted average.
3. Revenue quoted includes NGTL shareholder contribution.
4. New service only forecasted in 2005.
5. Forecast quantity is net of Alternate Access.

APPENDIX 2C: COST OF HAUL STUDY

TransCanada

NOVA Gas Transmission Ltd.

Cost of Haul Study
2003 Calendar Year

December 2004

TABLE OF CONTENTS

TABLES

1. SUMMARY

The purpose of this cost of haul study (“COH Study”) is to provide an indication of the relative cost of transporting gas between intra-Alberta and ex-Alberta deliveries for the Alberta System. This study is for the 2003 calendar year.

The results indicate that the average cost of haul for intra-Alberta deliveries is 71.9% of the average cost of haul for ex-Alberta deliveries, up from 67.9% in 2002. The intra-Alberta cost of haul to ex-Alberta cost of haul ratio increased in 2003 because in general, stations with a high cost of haul experienced proportionally large volume increases.

2. OBJECTIVES

The primary objective of this COH Study is to provide an indication of the relative cost of transporting gas between intra-Alberta and ex-Alberta deliveries. This COH Study incorporates two well accepted engineering/cost axioms as the basis for determining relative costs which are:

- unit costs increase with an increase in distance and
- unit costs decrease with an increase in pipe diameter

Distance is taken into account by modeling the flow of gas.

Diameter is taken into account by applying a relative cost index against the length of each pipe diameter that was used to transport the gas.

3. METHODOLOGY

For each month, a hydraulic simulation is performed to balance the gas received at each receipt point against the volume of gas delivered to each delivery point on the Alberta System. The flows are balanced based on the operating parameters and conditions employed on the Alberta System during that month. From this, the flow path from each receipt meter station to its associated downstream delivery stations can be determined. By reversing direction, the flow path to each delivery station can also be determined. Based on this hydraulic simulation, the costs of haul are calculated using the following steps:

1) The flow of gas is tracked in the reverse direction of the actual flow through all pipes from each delivery station to all upstream receipt stations that contribute flows to the delivery station. For each pipe in the system the following information is recorded:
   - the length and diameter of this pipe; and
   - the percent of volume at each downstream delivery station that was transported through this pipe. This is called the delivery station flow fraction. Each pipe gets a delivery station flow fraction for each downstream delivery station whose path it is in.

2) The cost of haul for a delivery station for the month is calculated by summing, for all pipes that have a delivery station flow fraction for that delivery station, the product of:
   - the length of the pipe;
   - the delivery station flow fraction; and
   - the unit cost index for this pipe diameter.

   The monthly COH for the delivery station is recorded. This process is repeated for every delivery station for all 12 months.

3) The overall annual average COH for a delivery station is determined by:
   - summing the product of the monthly COH and actual delivered volume (the "Relative Volume-Distance Cost") over all 12 months and
   - dividing this sum by the actual delivery station volume for the year.

   This process is repeated for each delivery station.

4) The average cost of haul for intra-Alberta deliveries and ex-Alberta deliveries is calculated by:
   - summing the product of the overall annual COH and total yearly volume for all stations in each group and
   - dividing this sum by the actual total volume for the year for all stations in each group.

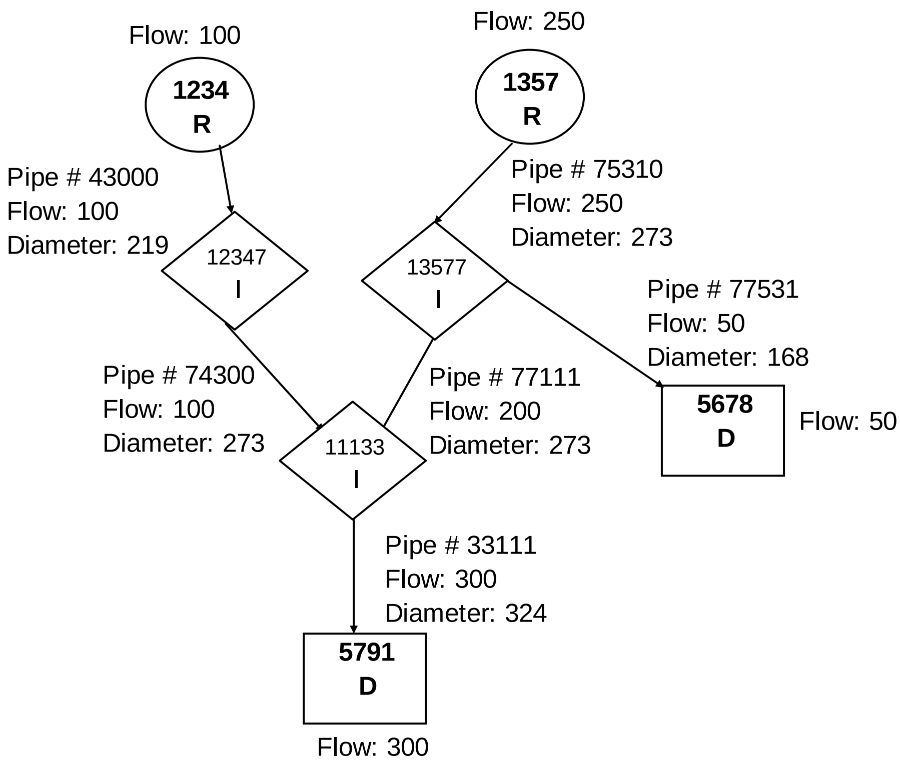
4. ILLUSTRATIVE EXAMPLE

The following is a detailed illustrative example of calculating the cost of haul for delivery stations in a simplified network. The actual delivery stations on the Alberta System have much more complex paths. Nevertheless, their COH is calculated in exactly the same way as described in this simplified example.

In this example the network is composed of two receipt meter stations (R) and two delivery stations (D). There are 6 pieces of pipe and three intermediate nodes (I) that join different pipes together. All stations, intermediate nodes and pipes have their unique identification number. Two of those intermediate nodes are junctions. For this example, assume that the following flows in 10^3m^3 occurred at those stations for the month of January:

Meter station number	Meter station type	Meter station flow in January
1234	R	100
1357	R	250
5678	D	50
5791	D	300

From the hydraulic simulation based on the above actual flows at the meter stations, the following schematic could be derived.



At this stage of the methodology the recording spreadsheet would look like Table #1.

Table #1

Pipe #	January flow
43000	100
74300	100
75310	250
77531	50
77111	200
33111	300

In Step 1 of the methodology, the length and diameter of each pipe and the delivery flow fractions for each delivery meter station at each pipe would be recorded. The flow fraction for a particular delivery station at a particular pipe is calculated as follows:

- Flow fraction = Sum of delivery station flow fraction on links leaving downstream node * flow on current link / sum of flows on all links entering downstream node.

For example, the delivery flow fraction for pipe 33111 for station 5791 is 1.0000 (or 100% of the flow) as it is the first pipe or link. The delivery flow fraction for pipe 77111 for station 5791 is 1.0000*(200/(200+100) = 0.6667 and the delivery flow fraction for pipe 75310 for station 5791 is 0.6667*(250/250) = 0.6667; that means that 67% of the volume for station 5791 flows through pipe 77111 and 75310 (the other 33% of the volume would come from a different path – pipes 43000 and 74300). At the end of Step 1 the recording spreadsheet for this example would look like Table #2.

Table #2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(4)*(5)/(7)
Delivery Station	**Pipe #**	**D/S Node**	**Flow Fraction on Links Leaving D/S Node**	**Flow on Current Link**	**Links Entering D/S Node**	**Flows from Links Entering D/S Node**	**Flow Fraction**
5791	33111	5791	1.0000	300	33111	300	1.0000
	77111	11133	1.0000	200	77111,74300	300	0.6667
	74300	11133	1.0000	100	77111,74300	300	0.3333
	43000	12347	0.3333	100	43000	100	0.3333
	77531	5678	0.0000	50	77531	50	0.0000
	75310	13577	0.6667	250	75310	250	0.6667
5678	33111	5791	0.0000	300	33111	300	0.0000
	77111	11133	0.0000	200	77111,74300	300	0.0000
	74300	11133	0.0000	100	77111,74300	300	0.0000
	43000	12347	0.0000	100	43000	100	0.0000
	77531	5678	1.0000	50	77531	50	1.0000
	75310	13577	1.0000	250	75310	250	1.0000

To calculate the cost of haul, described in Step 2, a cost index is multiplied by the flow fraction and length for each pipe. The cost index is based on historical costs for different pipe diameters and is derived by calculating a unit cost for each pipe size relative to the largest pipe diameter. This is the index used in determining the receipt point rates in accordance with the methodology approved by the EUB in Decision 2000-6. The relative cost index for each pipe diameter for 2003 is shown below.

Outside Diameter (mm)	Cost Index
114	66.45
168	25.45
219	15.16
273	10.25
324	7.27
356	6.77
406	5.47
457	4.51
508	3.66
559	3.30
610	1.83
660	1.69
711	1.57
762	1.47
864	1.26
914	1.18
1067	1.20
1219	1.00

All the information required to calculate the cost of haul for each delivery station for the illustrative month of January is now available. The product of the cost index, length and flow fraction is then summed for all pipes in the path to determine a total cost of haul for each station. After step 2 of the methodology, for the month of January, the recording spreadsheet would look like Table #3.

Table #3

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(4)*(5)*(6)	(9)=(4)*(5)*(7)
Pipe #	**January flow**	**Outside Diameter (mm)**	**Cost Index**	**Length in km**	**Delivery 5678 flow fractions**	**Delivery 5791 flow fractions**	**COH for 5678 in km**	**COH for 5791 in km**
43000	100	219	15.16	2	0.0000	0.3333	-	10.1
74300	100	273	10.25	5	0.0000	0.3333	-	17.1
75310	250	273	10.25	10	1.0000	0.6667	102.5	68.3
77531	50	168	25.45	3	1.0000	0.0000	76.4	-
77111	200	273	10.25	15	0.0000	0.6667	-	102.5
33111	300	324	7.27	5	0.0000	1.0000	-	36.4
					Total Cost of Haul		178.8	234.3

The COH calculations for the remaining months (February to December) would be done exactly the same way as demonstrated above. For this example assume that at the end of the year, the monthly results have been obtained for station 5678 as shown in columns 2 to 4 and station 5791 as shown in columns 5 to 7 of Table #4. By following Step 3, the overall volume weighted average annual COH for each delivery station can be derived as shown at the bottom of Table #4. It should be noted that the COH for meter station 5678 is not volume dependent, so will be 178.8 for all months as only gas from receipt meter station 1357 via pipe 75310 (COH = 102.5) and pipe 77531 (COH = 76.4) is physically available. The COH for station 5791 is volume dependant and does change from month to month as flow fractions for pipe in the station's path change.

Table #4

(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)=(5)*(6)
	Meter Station 5678			**Meter Station 5791**		
	Delivery Volume	**COH**	**Relative Volume-Distance Cost**	**Delivery Volume**	**COH**	**Relative Volume-Distance Cost**
Jan	50	178.8	8,940.5	300	234.3	70,291.6
Feb	75	178.8	13,410.8	350	224.5	78,589.9
Mar	75	178.8	13,410.8	400	235.3	94,112.7
Apr	50	178.8	8,940.5	350	195.3	68,339.1
May	50	178.8	8,940.5	300	219.7	65,898.4
Jun	50	178.8	8,940.5	300	219.7	65,898.4
Jul	-	-	-	320	224.5	71,853.7
Aug	50	178.8	8,940.5	340	234.3	79,663.8
Sep	50	178.8	8,940.5	350	236.3	82,690.3
Oct	50	178.8	8,940.5	300	221.6	66,484.2
Nov	50	178.8	8,940.5	310	207.9	64,463.3
Dec	50	178.8	8,940.5	310	218.7	67,792.4
Total	600		107,286.4	3,930		876,077.6
Annual Average		178.8			222.9	

In accordance with Step 4, the volume-weighted average annual cost of haul for all delivery stations, which in this example is two delivery stations, would be calculated as follows:

(178.8 * 600 + 222.9 * 3,930) / (600 + 3,930) = 217.1

5. RESULTS

Table 5.1 contains the COH results for 2003. The average cost of haul for:

- intra-Alberta deliveries was 673; and
- ex-Alberta deliveries was 936.

For 2003, the average cost of haul for intra-Alberta deliveries is 71.9% of the average cost of haul for ex-Alberta deliveries.

Table 5.2 compares the results for 2003 against the results of the study from the previous year.

TABLE 5.1
RESULTS FOR 2003

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	2003
Aver. Intra-Alberta COH	667	643	651	684	710	726	667	665	679	685	675	655	673
Aver. Ex-Alberta COH	848	856	920	995	1006	1021	987	972	973	947	896	840	936
Aver. Ex-Alberta to Intra-Alberta Ratio	1.27:1	1.33:1	1.41:1	1.45:1	1.42:1	1.41:1	1.48:1	1.46:1	1.43:1	1.38:1	1.33:1	1.28:1	1.4:1
Aver. Intra-Alberta to ex-Alberta Ratio	79%	75%	71%	69%	71%	71%	68%	68%	70%	72%	75%	78%	71.9%

TABLE 5.2
COMPARISON OF ANNUAL RESULTS, 2002 - 2003

	2003 COH	2002 COH	% Change
Average. Intra-Alberta COH	673.14	635.80	5.9%
Average Ex-Alberta COH	935.85	936.36	-0.1%
Average Ex-Alberta to Intra-Alberta Ratio	1.39:1	1.47:1	-5.4%
Average Intra-Alberta to ex-Alberta Ratio	71.93%	67.88%	6.0%

6. APPENDIX – COH FOR EACH DELIVERY STATION

COH for Ex-Alberta Deliveries:

Unit Number	Unit Name	Annual Volume (e3m3)	COH	Relative Volume-Distance Cost
1250	UNITY BORDER	49,767	398.9	19,850,403
1417	COLD LAKE BDR	71,517	316.3	22,623,450
1958	EMPRESS BORDER	52,742,832	964.8	50,884,255,792
2001	ABC SALES #1	9,467,269	752.6	7,125,313,606
2002	ALBERTA-MONTANA	32,792	499.8	16,389,644
2004	ABC SALES #2	9,483,104	747.0	7,084,252,269
3886	GORDONDALE BDR	2,722	536.2	1,459,451
6404	MCNEILL BORDER	21,851,648	1,039.4	22,711,727,347
8002	ESTHER DELIVERY	67,107	252.5	16,942,596
8003	MERIDIAN LK DLV	139,318	8.0	1,116,911
	Subtotal for ex-Alberta deliveries	93,908,075	935.9	87,883,931,469

COH for Intra-Alberta Deliveries:

Unit Number	Unit Name	Annual Volume (e3m3)	COH	Relative Volume-Distance Cost
2360	COCHRANE EXTRCT	1,177,924	618.7	728,758,389
3050	SARATOGA SALES	4,698	654.6	3,075,205
3051	SIMONETTE SALES	7,215	0.4	2,802
3052	COLEMAN SALES	4,039	737.6	2,979,214
3053	SUNDRE SALES	4,990	476.3	2,376,732
3055	GRANDE PRAIR SL	-	-	-
3058	LUNDBRECK-COWLE	1,121	502.2	563,152
3059	ALLISON CRK SLS	8,672	753.9	6,538,159
3060	CARROT CREEK SL	12,777	595.5	7,608,964
3061	PEMBINA SALES	27,481	433.8	11,920,132
3062	E. CALGARY B SL	120,161	1.6	192,487
3063	VIRGINIA HLS SL	2,289	460.1	1,053,325
3065	RAT CREEK SALES	-	-	-
3067	BIGSTONE SALES	4,642	107.3	498,137
3068	BEAVER HILL SLS	36	326.2	11,742
3069	WILSON CRK S SL	4,783	99.4	475,621
3071	CYNTHIA SALES	-	-	-
3072	PADDY CREEK SLS	44,632	63.8	2,846,913
3073	PRIDDIS SALES	45,630	572.0	26,100,357
3074	WATERTON SALES	208,703	0.0	3,817
3076	RAINBOW SALES	71	1.6	114
3077	FIRE CREEK SALE	4,440	1,115.7	4,953,521
3078	JUDY CREEK SALE	-	-	-

Unit Number	Unit Name	Annual Volume (e3m3)	COH	Relative Volume-Distance Cost
3080	LOUISE CREEK SL	29,009	409.6	11,882,677
3082	ELK RIVER S SLS	-	-	-
3083	RAINBOW LK SLS	-	-	-
3085	DEEP VLLY CR SL	4,039	0.6	2,480
3086	PINE CREEK SLS	4,387	417.8	1,832,831
3087	GOLD CREEK SLS	20,802	137.1	2,852,957
3088	VALHALLA SALES	3,172	466.5	1,479,546
3091	OUTLET CREEK SL	91	29.9	2,713
3092	MOOSEHORN R SLS	7,677	257.6	1,977,268
3093	HARMATTAN-LEDUC	-	-	-
3094	BRAZEAU N SALES	100	438.2	43,910
3095	SAKWATAMAU SALE	19,377	355.6	6,890,297
3097	CHICKADEE CK SL	20,460	333.0	6,812,534
3098	DUTCH CREEK SLS	-	-	-
3099	SOUSA CRK E SLS	4,219	37.6	158,405
3100	HEART RIVER SLS	11,528	0.9	10,593
3101	CAROLINE SALES	46	623.0	28,407
3103	VIRGO SALES	4,063	82.0	333,304
3105	CRANBERRY LK SL	107,452	457.5	49,156,942
3106	CARMON CREEK SL	184	736.7	135,631
3107	FERGUSON SALES	33,786	756.9	25,574,220
3109	CALDWELL SALES	4,406	203.0	894,176
3110	MARSH HD CR W S	61	621.7	38,171
3111	MINNOW LK S. SL	1,028	142.2	146,114
3112	FALHER SALES	29,126	879.4	25,613,795
3113	TWINLAKES CK SL	140	652.6	91,496
3114	WEMBLEY SALES	18,825	289.5	5,450,678
3115	USONA SALES	32,499	53.9	1,751,483
3117	GRIZZLY SALES	28,514	172.0	4,905,804
3118	GILBY N#2 SALES	54	10.4	559
3119	DEADRICK CK SLS	4,042	145.1	586,305
3120	MILDRED LK SLS	1,236,125	1,059.5	1,309,634,423
3123	MILDRED LK #2 S	545,728	1,053.0	574,643,716
3124	DEEP VY CK S SL	-	-	-
3125	HUGGARD CREEK S	4,276	716.4	3,063,249
3128	GARRINGTON SALE	2,880	80.1	230,780
3300	OTAUWAU SALES	1,424	162.5	231,385
3301	SAULTEAUX SALES	292	300.9	87,853
3304	FORESTBURG SLS	7,259	881.1	6,395,257
3305	CHIGWELL N. SLS	3,414	0.8	2,631
3368	NOEL LAKE SALES	50,424	658.2	33,187,433
3405	RIM-WEST SALES	245,069	0.1	14,793
3406	REDWATER SALES	93,964	798.0	74,986,835
3410	VIKING SALES	108,688	249.8	27,147,790
3411	MONARCH N. B SL	2,698	0.5	1,256
3412	WAYNE N B SALES	19,129	1.4	26,855

Unit Number	Unit Name	Annual Volume (e3m3)	COH	Relative Volume-Distance Cost
3413	ATMORE B SALES	6,966	0.2	1,317
3414	HANNA S B SALES	8,780	853.5	7,493,814
3416	COUSINS A SALES	-	-	-
3418	COUSINS C SALES	1,212	338.8	410,672
3419	INLAND SALES	976,455	1,055.0	1,030,112,179
3421	WIMBORNE SALES	-	-	-
3422	THORHILD SALES	3,613	1.0	3,448
3423	BASHAW WEST SLS	467	598.5	279,670
3424	GRANDE CENTRE S	20,066	197.2	3,956,745
3425	WOOD RVR SALES	60,363	507.4	30,629,909
3427	WESTLOCK SALES	3,777	2.0	7,711
3429	ST. PAUL SALES	18,341	527.1	9,667,968
3430	FERINTOSH SALES	1,682	361.2	607,503
3432	PETRO GAS PLANT	977,305	900.4	879,997,188
3434	AMOCO INLET	1,486,708	1,032.6	1,535,141,986
3435	PAN CAN INLET	312,780	949.7	297,056,494
3437	HARMATTAN SALES	461	742.3	341,969
3438	REDWATER B SL	41,200	915.5	37,718,632
3439	SHEERNESS SALES	4,432	1,108.8	4,913,498
3440	PROGAS PLANT	211,684	988.0	209,135,458
3444	PINCHER CRK SLS	7,030	474.5	3,335,512
3445	KAKWA SALES	-	-	-
3446	BITTERN LAKE SL	67,441	709.0	47,816,068
3448	ROSS CREEK SLS	93,808	514.1	48,222,958
3449	FLEET SALES	3,037	147.1	446,692
3452	JOFFRE EXTRACTI	89,197	333.2	29,717,606
3453	GREEN GLADE SLS	-	-	-
3454	PENHOLD N SALES	66,691	186.7	12,451,618
3456	ELK POINT SALES	14,398	54.0	777,260
3457	MITSUE SALES	-	-	-
3458	COUSINS B SALES	958,889	344.0	329,876,346
3460	LANDON LAKE SLS	10,859	4.8	51,769
3462	NIPISI SALES	-	-	-
3464	GREENCOURT W SL	17,799	84.5	1,503,707
3465	DEMMITT SALES	718	147.5	105,928
3467	KILLAM SALES	-	-	-
3468	BLEAK LAKE SLS	12,215	448.3	5,475,831
3469	EVERGREEN SALES	368	1.0	367
3470	NOSEHILL CRK SL	16,789	290.8	4,881,874
3471	BLUE RIDGE E SL	50,141	41.1	2,059,055
3472	INNISFAIL SALES	1,828	293.0	535,549
3474	LLOYD CREEK SLS	-	-	-
3476	LAC LA BICHE SL	3,943	439.9	1,734,389
3477	RICINUS S SALES	-	-	-
3478	ONETREE SALES	20,370	0.9	18,720
3479	NOSEHILL CRK N.	4,868	609.5	2,967,019

Unit Number	Unit Name	Annual Volume (e3m3)	COH	Relative Volume-Distance Cost
3481	SAWRIDGE SALES	35,170	8.2	289,499
3482	LONE PINE CK SL	11,827	1.4	16,143
3483	CRAMMOND SALES	9	0.1	1
3484	CARIBOU LAKE SL	-	-	-
3485	SHORNCLIFFE CRK	9	893.4	8,040
3486	WESTERDALE SLS	3,542	7.7	27,196
3488	ARDLEY SALES	11,937	741.3	8,848,697
3489	ATUSIS CREEK SL	102,770	788.2	81,004,842
3490	GAETZ LAKE SLS	6,868	0.7	4,563
3491	JOFFRE SLS #2	574,116	331.9	190,556,055
3492	JOFFRE SLS #3	478,622	331.3	158,559,814
3493	MEYER B SALES	-	-	-
3494	SILVER VLY SLS	1,837	696.7	1,279,682
3495	CAVALIER SALES	1,216	0.1	93
3496	CHIPEWYAN RIVER	224,167	339.2	76,037,505
3497	SUNDAY CREEK SO	47,875	60.6	2,901,067
3562	AMOCO SALES TAP	55	1,085.7	59,280
3600	STORNHAM COULEE	27,334	537.9	14,702,579
3604	MARGUERITE L SL	59,382	1,037.0	61,581,361
3605	LEMING LAKE SLS	1,632,538	513.6	838,396,634
3606	LOSEMAN LAKE SL	289,033	193.7	55,983,463
3609	SARRAIL SALES	42,234	562.2	23,744,203
3610	RANFURLY SALES	27,274	785.5	21,424,635
3611	HERMIT LAKE SLS	161,007	629.6	101,362,318
3612	CONKLIN W SALES	136,554	367.0	50,118,767
3613	SHANTZ SALES	1,004	55.1	55,328
3615	HAYNES SALES	27,332	320.8	8,767,737
3616	GAS CITY SALES	25,296	535.2	13,537,488
3618	JENNER EAST SLS	1,858	1,086.7	2,018,700
3621	LOSEMAN LK SL#2	9,361	194.2	1,817,953
3622	CHEECHAM W. SLS	14,886	378.7	5,636,851
3623	FERINTOSH N. SL	286	804.4	229,990
3624	GODS LAKE SALES	64	853.9	54,562
3626	MIRAGE SALES	-	-	-
3632	EAST CALGARY SA	-	-	-
3633	RUTH LK SLS	152,195	1,136.2	172,931,216
3634	CANOE LAKE SALE	243	0.7	169
3635	ROD LAKE SALES	1,980	445.1	881,451
3637	RUTH LK SLS #2	1,112	1,136.2	1,263,917
3639	VEGREVILLE SALE	16,834	998.2	16,803,716
3640	RUTH LK SLS #3	862	1,156.3	996,134
3642	VENTURES KV OIL	164,949	1,090.2	179,827,691
3884	COALDALE S. JCT	3,740	150.5	562,927
3885	CHIP LAKE JCT	7,383	0.7	4,906
5007	HOUSE RIVER	29,559	668.0	19,744,480
5024	CROW LAKE SALES	-	-	-

Unit Number	Unit Name	Annual Volume (e3m3)	COH	Relative Volume-Distance Cost
6903	MCNEILL A UTIL	60	1,008.9	60,734
	Subtotal for Intra-Alberta deliveries	14,305,815	673.1	9,629,823,151

APPENDIX 2D: DIRECT EVIDENCE OF DR. J. S. GASKE

BEFORE THE ALBERTA ENERGY AND UTILITIES BOARD

NOVA Gas Transmission Ltd.

2005 General Rate Application, Phase 2

Written Testimony of
Dr. J. Stephen Gaske
On Behalf of
NOVA Gas Transmission Ltd.

Zinder Companies, Inc.
15 April 2005

TABLE OF CONTENTS

1. Written Testimony of Dr. J. S. Gaske

1.0 Introduction

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7508 Wisconsin Avenue, Suite 300, Bethesda, MD 20814.

Q2. Would you please describe your educational and professional background?

A. For the past 28 years, I have been engaged in consulting, studying, and teaching about economic and financial issues related to regulated industries. During this time I have testified or filed testimony or affidavits as an expert witness in numerous regulatory proceedings.

I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from The George Washington University. I also received a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics. A detailed curriculum vitae is attached as Appendix A of this testimony.

Q3. Are you familiar with the operations of Nova Gas Transmission Ltd.'s ("NGTL's") Alberta System?

A. Yes. During the 1990s I provided extensive consulting advice to NGTL in connection with NGTL's Products and Pricing initiative which resulted in the essential elements of the Alberta System's existing toll design. In addition, I appeared before the Alberta Energy and Utilities Board ("EUB") on behalf of NGTL as an expert witness on cost allocation and rate design matters in NGTL's 2004 GRA Phase 2 proceeding.

Q4. What is the purpose of your testimony?

A. In Decision 2004-097 concerning Phase 2 of NGTL's 2004 General Rate Application ("GRA"), the Alberta Energy and Utilities Board ("EUB" or "Board") approved NGTL's existing toll design methodology for the Alberta System, which is based on a settlement between NGTL and its customers. However, in Decision 2004-097 the Board also ordered NGTL to file a 2005 Phase 2 General Rate Application that includes additional cost analyses that were not before the Board during the 2004 GRA. Since that time, NGTL has prepared fully-allocated cost of service studies of its Alberta System using its Existing Methodology for conducting a cost-of-service study and alternative cost-of-service study methodologies. It is presenting these cost analyses for the Board's consideration in this 2005 GRA Phase 2 Application.

In the context of this Application, I have been asked by NGTL to:

- describe the concepts and principles that are important for analyzing NGTL's costs of providing services;
- evaluate from an economic and ratemaking perspective the reasonableness of each of the cost allocation and rate structure methodologies examined by NGTL;
- review NGTL's existing accountability provisions for intra-Alberta delivery services and render an opinion as to whether these are reasonable and appropriate; and,
- review the role of competition in determining a reasonable rate structure for NGTL's Alberta System.

1.1 Summary of Testimony

Q5. Would you please summarize your testimony?

A. NGTL's Alberta System provides several different transportation-related services to more than 200 customers at more than 1,000 points within the Alberta portion of the Western Canadian Sedimentary Basin. In order to establish rates for its different services and geographically-dispersed customers, it must determine a reasonable method for allocating costs to its various services and customers.

In section 1.2 of this testimony I describe the concept of pipeline costs and the various cost concepts that are relevant for analyzing the cost of providing specific services or service for specific customers. As I discuss in this testimony, the costs of serving any single customer on the system generally cannot be determined with any degree of precision. Moreover, the nature of regulated ratemaking usually prevents a pipeline or regulated entity from charging rates that precisely reflect actual costs. Consequently, a regulated rate structure generally will attempt to reflect a reasonable relationship between the costs of serving different customers.

In section 1.3 of this testimony, I discuss the standards that should be used in evaluating a fully-allocated cost of service study and then, in section 1.4, I apply these standards in evaluating NGTL's Existing Methodology for conducting a cost-of-service study. The alternative methodologies for allocating costs to services and customers are evaluated in section 1.5 and a summary of my evaluations is contained in section 1.6. The fact that a large portion of a NGTL's costs cannot be precisely attributed to any one service or customer, means that there are an infinite number of cost allocation outcomes that could satisfy the theoretical and practical constraints of a reasonable rate structure. For this reason, the utility must develop a method that reasonably meets the theoretical and practical constraints posed by its cost and market characteristics and that, within those constraints, also satisfies any other explicit public policy objectives.

My analysis of NGTL's Existing fully-allocated cost of service methodology and the Alternative methodologies contained in NGTL's Application leads me to conclude that NGTL's Existing Methodology for conducting a cost-of-service study continues to be appropriate at this time because it provides a reasonable allocation of costs that has achieved customer acceptance.

In section 1.7, I examine the existing accountability provisions for intra-Alberta delivery service and conclude that changes could be made to the Extension Annual Volume ("EAV") component of the FCS charge in order to align the EAV requirements with the costs of particular intra-Alberta facilities. However, it is not a clear-cut case that changes to accountability are required. The desirability of such a change depends, among other possible considerations, on the level of risk that is appropriate for the Alberta System to undertake.

Finally, in section 1.8, I discuss the competitive circumstances and related policy issues that are relevant for this GRA Phase 2 proceeding.

Q6. What are the main conclusions of your testimony?

A. The main conclusions of my testimony with regard to the theory of cost-of-service studies are as follows:

1) There are many different possible definitions of cost when one refers to the "cost" of providing specific pipeline services or the costs of serving individual

pipeline customers. Prominent among the possible definitions are concepts such as average costs, short-run marginal costs, long-run marginal costs, stand-alone costs, opportunity costs, and fully-allocated costs;

2) Because of the pervasiveness of common, joint and inseparable costs it generally is impossible to isolate and measure the costs of providing specific pipeline services or the costs of serving individual pipeline customers;

3) From the perspective of cost causation, there is a range of costs that reflect the various economically-relevant "costs" of providing specific pipeline services or the costs of serving individual pipeline customers. From a short-run perspective the range extends from the pipeline's marginal variable cost at the low end, to the value of service and opportunity cost of potential customers at the high end. From a long-run perspective, the range extends from long-run marginal costs at the low end to stand-alone costs at the high end.

4) Rates set equal to one of the economically relevant concepts of cost causation generally will not generate revenues equal to the regulated revenue requirement because there are large economies of scale in pipeline cost structures. Furthermore, regulated rates are based on the embedded, net depreciated original cost of facilities rather than the replacement cost of facilities denominated in current dollars, which further limits the ability of conventional regulated rates to reflect cost causation.

5) A proper fully-allocated cost study should produce a compromise result that generally meets the constraints posed by: (i) the economically-relevant concepts of cost causation, and (ii) the overall revenue requirement of the

regulated company. Generally, there is a wide range of fully-allocated cost of service methodologies that can meet these constraints and reasonably reflect costs. The choice among cost allocation methods should depend upon considerations such as the relative elasticities of demand, and a weighing of various ratemaking principles and policy objectives.

The main conclusions of my testimony with regard to the existing and alternative cost-of-service study methodologies examined by NGTL are as follows:

1) Because the Alberta System incurs common, joint and inseparable costs to provide nearly all of its services, it generally is impossible to determine the level of costs that are causally-related to any particular service or customer. This is especially true for service combinations such as FT-R/FT-A and FT-R/FT-D that provide access to NIT because each customer of these service combinations has commercial access to the entire system and can receive gas that is delivered by displacement.
2) NGTL's Existing Methodology for conducting a cost-of-service study is a fully-allocated cost of service methodology that employs reasonable procedures for allocating costs fully, and in a cost-reflective manner, among the Alberta System's services and customers.
3) Each of the alternative cost-of-service study methodologies presented by NGTL also could provide a reasonable approach for allocating the Alberta System costs, depending upon the principles, goals and policies that are considered to be most important.

4) The Alberta System faces a considerable amount of actual and potential competition that constrains its rates in both the intra-Alberta and export gas transportation markets. This competition is an important consideration in establishing rates for the Alberta System because the system has lost significant amounts of business to competitors in the past several years and will continue to face competition in the future.

5) NGTL's method of splitting transmission costs between the receipt and delivery components of intra-Alberta transportation rates is a reasonable method of assigning costs based on the constraints posed by (i) the general relationship that physical gas flows required to transport gas to intra-Alberta markets have historically flowed approximately 50 percent of the distance of physical flows required to provide transportation to export markets, and (ii) the goal of splitting export transportation rates 50-50 between the receipt and delivery component of the rates. A change in either one of these constraints will require a change in the other constraint under the current rate structure.

6) The FT-P service provides a more accurate method for determining the relative costs of specific intra-Alberta transportation services than does the FT-R/FT-A service combination.

7) The FT-A component of the FT-R/FT-A intra-Alberta transportation service combination provides reasonable and appropriate accountability when considered in conjunction with the Facilities Connection Service ("FCS") charge for facilities. Some changes to the EAV component of the FCS charge could be considered however, if it is deemed desirable to change the

allocation of risks among parties and/or align the level of the EAV commitments with costs of specific facilities.

1.2 The Concept of Pipeline "Costs"

Q7. What does it mean to determine the "cost" of providing pipeline service to a particular customer or group of customers?

A. There are many different cost concepts that can be considered when one sets out to determine the cost of providing service to any one pipeline customer or group of customers. Consequently, when someone advocates that a cost of service study is required to determine the costs of providing service to particular customers, it is necessary to clarify what is meant by the term "cost."

For example, there are important distinctions to be made between marginal costs and average costs and there are many costs that may not be precisely attributable to the usage of any one particular customer. Therefore, an important part of conducting, or evaluating, a cost-of-service study requires one to specify which types of "costs" one is attempting to estimate.

1.2.1. The Role of a Fully-Allocated Cost Study

Q8. When you use the term "fully allocated" cost study in this testimony, what do you mean?

A. For an entity whose rates are regulated, a "fully allocated" cost study distributes the total revenue requirement (the amount the company is allowed to collect in the aggregate) over the entire basket of regulated services using a methodology that attempts to reflect the manner in which costs are incurred.

Q9. Is there a single prescribed methodology, applicable among all jurisdictional authorities, for conducting a "fully-allocated cost" study?

A. No. Specific methodologies and techniques vary. They can vary over time, among different regulated entities, and among different service offerings by regulated entities. Specific allocation techniques or ratemaking formulae generally are not prescribed by statute. Instead, when the issue of specific methodologies has arisen (either before regulatory entities or by courts who interpret regulatory statutes), the result that emerged was that techniques might vary, depending on the facts and circumstances, and that the end result (i.e., "just and reasonable" rates) was governing.

Q10. Does economic and ratemaking literature support the proposition that the specific "costs" of providing particular services generally cannot be determined by a fully-allocated cost of service study and that there are many methods by which to allocate costs as a predicate to the design of "just and reasonable" regulated rates?

A. Yes. By illustration, in *Principles of Public Utility Rates*, Bonbright, Danielsen and Kamerschen state at page 110:

> [N]o ***such simple identification of reasonable rates with rates measured by costs of service is attainable***. One major reason is due to the excessive complexity of the cost relations … Two other reasons are due to ***the inherent conflict between a cost-based system of reasonable rate levels and a cost-based system of specific rates and rate relationships***. The sources of this conflict lie, on the one hand, in the fact that incremental costs are non-additive so cost-based rates under circumstances of decreasing cost will fail to meet a company's revenue requirement. On the other hand, ***the problem of joint and common costs makes it impossible to allocate, at least on a cost basis, the costs attributable to specific classes and units of service***. (Emphasis added).

Q11. Why is it important to understand that it generally is impossible to isolate and identify the pipeline costs that are attributable to specific services or customers?

A. Clearly, when one speaks of the need to determine the "costs" of providing specific services, or the need to determine the "costs" of serving specific, individual customers, it is important to understand that it generally is impossible to determine such costs when a large portion of the costs are incurred on behalf of multiple services or customers. Instead, there generally is a wide range of "costs" associated with individual services or customers and this range depends upon whether one is considering short-run costs (which include "opportunity" costs) or long-run costs. This range of costs is bounded in the long run by long-run marginal costs and stand-alone costs. In the short run the range is bounded by the pipeline's variable costs and the customers' opportunity costs. An attempt to perform many cost studies that each uses one of the relevant cost concepts would be enormously difficult or impossible, and still would not resolve the conflict as to which cost concept is the most appropriate. Nor would it be the case that the costs determined by any one of the studies would add up to the pipeline's regulated revenue requirement. Thus, a fully-allocated cost of service study should be properly understood to be a compromise among various cost concepts that is guided by policy and pragmatic considerations.

Q12. Are these foregoing concepts illustrated in recent regulatory rulings of the EUB?

A. Yes. In its September 24, 2004 GRA Phase 2 Decision 2004-079 for ATCO Pipelines, the Board stated as follows (page 5, *emphases* added):

> Traditionally, a GRA Phase 2 decision will consider and determine how to apply the appropriate rate design criteria for the determination of just and reasonable rates to collect the utility's approved revenue requirement, determine the rates for the proposed services and establish the appropriate terms and conditions for these services. ***Certain of those rate design criteria address the accuracy of the cost allocation methodologies used to support the collection of a share of revenue requirement from***

> ***each class through rates***. The primary tool utilized in determining an appropriate cost allocation is a cost of service study (COSS). A COSS will ordinarily analyze the costs incurred in providing regulated services, categorize or functionalize these costs and then determine an appropriate set of methodologies for the allocation of these costs. ***An appropriate allocation may be done in one of any number of ways, including on a fully allocated cost basis for all costs or a mixed allocation of costs with costs that can not be attributed to a single customer class (general system costs) being allocated on a fully allocated basis and costs that can be attributed to a single customer class being direct assigned to that class***.

Q13. Have other regulatory agencies in Canada recognized that there is a relatively large range within which any particular regulated rate can be determined to comply with the statutory standard of "just and reasonable?"

A. Yes. By illustration, the National Energy Board has acknowledged over a span of nearly two decades that the practical limits of "just and reasonable" interruptible pipeline rates are (i) at the lower end, the variable cost of service and (ii) at the upper end, the value of service to the customer. The range of reasonableness is self evident for virtually any category of pipeline service. Rates that fail to recover the out-of-pocket, variable costs of service are generally improper on their face, absent some compelling, express public interest justification to the contrary. At the other limit, rates that exceed the value of service to the customers are generally not sustainable, insofar as the customer will attempt either to forego consumption entirely, or to substitute cheaper alternative service from another vendor. The Board has recognized this problem in approving load retention ("LRS") rates in several proceedings in the past.

Q14. In general terms, how is a fully-allocated cost study conducted?

A. In some instances it may be possible to identify a particular cost that is incurred in providing only one service and that is for the benefit of only one customer class.

These costs can be *directly assigned* to that service and class because they are unrelated to providing any other service or service for any other class. Some costs may also be directly assigned to services or customer classes if the company has records that isolate the incremental costs actually expended for each customer class.

In a large integrated pipeline system, the vast majority of costs cannot be directly assigned because the same costs are incurred in providing multiple services to multiple customer classes. Instead, these costs must be *allocated* among the various services and/or classes in some manner. Costs that vary in relation to a specific, measurable service characteristic can be allocated based on that service characteristic. For example, metering costs vary with the number of receipt and delivery points which allows a portion of metering costs to be allocated to rate components associated with each receipt and delivery point. Similarly, total transmission costs often vary according to distance, diameter, or other characteristics that can be used to allocate the transmission costs to specific customers or services. In cost allocation *a set of ratios*, or allocation factors, is calculated using the amount of the relevant, measurable service characteristic consumed or used by each class or service.

It is important to note that the factor or service characteristic that causes a specific cost category to vary can be different depending upon the specific facts and circumstances present for any given company. In addition, some cost categories may not vary in direct proportion to any measurable service characteristic, but they might have at least one (there could be several) measurable service characteristic that partially cause(s) the cost to vary and reasonably correlates with the total amount expended by the company for that particular cost category.

To the extent that one or more measurable service characteristic can be identified that causes a cost category to vary, or that reasonably correlates with the level of that cost category, the costs in that category are "allocable" costs.

Many cost categories, such as most Administrative and General costs, are not truly allocable because there is no measurable service characteristic that correlates strongly with the level of costs in that category. Nevertheless, those unallocable costs are often "allocated" to individual services using ratios that are based in some way on the measurable service characteristics.

Q15. How do cost allocation and rate design interrelate in the cost analysis?

A. As a matter of computational mechanics, the analyst first allocates the costs associated with each function to each service or rate class, and often to different cost classification categories (e.g., fixed, variable, distance-related, customer, demand, commodity, seasonal, diurnal, etc.) within each service or rate class. Next, the analyst designs rates based on the costs that are allocated to the cost classification categories within each service or rate class.

However, it would be incorrect to assume that the mechanics of the computation represent the order in which the analyst approaches the task. Instead, the analyst starts with some understanding of the utility's cost structure, operations, markets and customers. The analyst also considers factors such as the type and quality of data available, the metering technology, and the level of complexity that is practicable for the final rates. With all of these considerations in mind, the analyst reviews what services will be offered, what rate classes will be established, what cost functions and classifications are to be used to reflect costs, and what rate components will be used to collect costs.

Thus, before the cost allocation process begins the analyst knows generally what the final rate and service structure is to be. In other words, the entire *skeleton* of the final rate structure is generally known before the initial cost allocation begins. Knowing in advance what the skeleton of the rate structure and rate design is to look like, the analyst then begins to allocate costs to the different cost classifications within each service or customer class and then uses the costs allocated to each cost classification category as a basis for designing final rates. The point is that – although rate calculation appears to be a linear process that starts with cost allocation and then proceeds to rate design – cost allocation and rate design should be properly understood to be steps in an integrated and iterative process.

Q16. In every fully-allocated cost study, are all elements of the revenue requirement always costs that are fully allocated or distributed?

A. No. In many cases, a portion of the revenue requirement in reality may consist of some category of *revenues* (derived on some separate bases) that are treated essentially as "credits" to the aggregate cost of service. Some examples can include: (1) revenues from for interruptible service, which may be derived by an exogenous formula and effectively credited to the total cost of service prior to the design of firm service rates; and (2) revenues from "non standard" or ancillary services.

Q17. What level of detail is utilized in a fully-allocated cost study?

A. The level of detail employed in a cost study can be very different depending upon the cost structure, operations, and goals of the allocated cost of service study. Virtually every fully-allocated cost study employs the concept of averaging to one degree or another, and the level at which costs are averaged can have a significant effect on the estimate of the "cost" of service for each group of customers. Moreover, the type of allocation factor to use can depend in part on the weighting that one gives to different cost characteristics and the usage characteristics of the customer base.

Q18. After any preliminary allocation or distribution of pipeline system costs, what are some of the principles, standards or considerations that might lead to departures from such allocated costs in order to establish just and reasonable rates?

A. There are many such considerations. For example, "allocative efficiency" might lead the utility to propose higher relative rates in circumstances of excess demand, or lower relative rates in instances of excess supply that might otherwise go unused. Also, some cost allocation calculations function as a general point of reference and not a final, precise mathematical formula for rates. For example, the mechanical application of a certain cost formula might result in final rates which, if approved and effectuated all at once, are judged to be too abrupt a change. Sometimes, traditional formulae are adjusted on case by case bases, either in one direction or another, in order to address pragmatically the then current facts and circumstances. Sometimes, rate differentials otherwise determined by formula are modified in order to promote some social or public interest objective. Any of these foregoing illustrative adjustments might be (i) initiated by the utility itself, or (ii) agreed upon by all or most of the customer base, or (iii) imposed by the regulatory agency. The type of practical or policy adjustments to allocated costs that often occur at the rate design level may be circumscribed by the EUB guideline that ultimate rates generally should be within a band of 95%-105% of allocated costs. This guideline places additional emphasis on the need to consider all relevant criteria for proper ratemaking and cost apportionment when evaluating cost allocation methods.

1.2.2. Marginal (or Incremental) Costs v. Average Costs

Q19. What is the difference between "marginal" (or "incremental") cost and "average" cost?

A. Marginal cost reflects the additional cost that must be expended to provide one additional unit or service; or, depending upon the context, it is the cost that can be avoided if usage of the service is reduced by one unit. The concept of incremental cost is essentially the same as the concept of marginal cost, however, incremental cost involves the cost associated with providing increments of service greater than just one additional unit of service. With regard to pipeline services, incremental cost is often the more useful of the two concepts because capacity and utilization often are added in relatively large increments.

Average cost is simply the total costs of providing service, divided by the number of units of service provided. Overall average cost is very easy to calculate on an aggregate basis if there is a single measure of output, such as throughput, and no attempt is made to further identify factors that can affect the cost of serving one individual customer versus another. Usually, however, there can be significant differences in the costs of serving specific individual customers such that it is rare that the cost of serving any one customer is equal to the average system-wide costs. In an attempt to account for these differences, pipelines often will offer a variety of services, and develop a multi-part rate design that attempts to recover costs in a manner that reasonably reflects the differences in the costs of serving specific customers.

Q20. Are there different types of marginal cost and different types of average cost?

A. Yes. Even within each of these two cost categories there are distinctions between (i) short-run marginal costs and long-run marginal costs, and (ii) the numerous distinctions that can be made for purposes of determining the average costs for specific categories of customers (e.g., classes), specific services (e.g., firm, interruptible, network, point-to-point, etc.) or specific variables that cause costs to vary (e.g., number of customers, peak demand, total throughput or commodity usage).

Q21. Which type of cost is most relevant for determining the cost of serving a particular customer?

A. From an economic standpoint, marginal costs are most relevant because they reflect the amount of society's resources that must be used in order to provide additional units of service. However, which type of marginal cost to use as a basis for setting prices depends upon the primary goal to be achieved and the time-frame that is to be considered.

For example, short-run marginal cost reflects the cost or value attached to a resource or service at a specific point in time when many of the production inputs (e.g., supply, capacity or production capabilities) are fixed. Long-run marginal costs reflect the cost of production when all factors of production are assumed to be variable so that fixed factors of production can be adjusted to provide an efficient amount of a product or level of service.

Prices (or rates) that are equal to *short-run* marginal cost generally promote the most efficient usage and allocation of available resources at any given point in time. On the other hand, prices (or rates) that are equal to *long-run* marginal cost can promote efficient construction of facilities and capacity. However, exclusive use of either of these forms of marginal cost pricing is unlikely to produce revenues that are equal to the revenue requirement of a regulated entity. Consequently, various forms of average cost, as determined by some form of cost allocation study, are generally used as a starting point for establishing regulated rates.

Q22. How do prices based on short-run marginal costs work in practice?

A. Short-run marginal cost reflects the fact that at any given point in time, there are a fixed, limited amount of specific resources available. Economic theory suggests that the most efficient method for allocating the existing resources to potential customers is to sell the existing resources at a price that reflects whatever the market is willing to bid for the resources at any point in time, so long as the price is sufficient to recover any variable costs required to produce additional units of the product or service. Prices in many unregulated markets, especially commodity markets such as the natural gas spot market, reflect short-run marginal costs.

It is noteworthy that during periods of tight supply and relatively high prices, the concept of "short-run marginal cost" does not necessarily reflect the producers' costs; instead, at these times short-run marginal cost generally reflects the *opportunity cost*, or the value attached to natural gas by the marginal consumer (i.e., that consumer who attaches the lowest value to natural gas, but is still willing to pay the market price required to buy the last unit of supply available at that time).

Q23. How can short-run marginal costs operate with respect to setting rates for pipeline services?

A. Sunk costs of long-lived assets such as pipelines or compressors generally do not enter into the calculation of short-run marginal costs because they are essentially irrelevant for any prospective decisions concerning whether to incur additional costs in order to provide an additional unit of service. For a pipeline, short-run marginal costs can vary within a wide range under changing conditions during various periods of time, similar to the variations in the gas commodity markets, however, although it is closely related to the gas commodity market, the pipeline market is a separate market. Prices based solely on short-run marginal costs could be set by allowing a pipeline to charge whatever the market will bear at any given point in time. Such prices could be as low as the pipeline's variable costs (e.g., compressor fuel), or as high as the market is willing to pay. Obviously, rates that are established in this manner could not be subject to regulatory constraints and would not necessarily reflect the costs incurred by the pipeline to provide service.

However, there are many ways in which short-run marginal cost concepts can be reflected in regulated rates. For example, demand for pipeline capacity often varies on a seasonal basis such that the value of such capacity often is far above the regulated rate during peak periods, and the value also may be lower than the regulated rate during off-peak periods. Seasonal rates are used by many regulated companies in order to provide rates that approximately reflect seasonal variations in the value of capacity.

Q24. How do long-run marginal costs operate in pipeline markets?

A. The concept of long-run marginal costs incorporates costs that may be fixed in the short-run, but that can be altered or replaced in the long-run if market conditions change. Unlike short-run marginal costs, long-run marginal costs do not incorporate the opportunity costs of customers. Long-run marginal costs are significant for evaluating pipeline rates, and possibly competitive situations, because it is economically efficient to construct capacity sufficient to serve all customers who are willing to pay rates at least as great as the long-run marginal cost of providing the service, including the cost of adding the last unit (or increment) of capacity.

Because pipelines experience substantial economies of scale related to providing and maintaining transmission facilities, a single large pipe serving a market is considerably less costly than two or more small pipes serving the same market. This characteristic is a major reason that pipelines sometimes do not face strong competition and that pipeline rates are generally regulated. However, to say that pipelines are characterized by “economies of scale” means that, over a wide range of capacities, the long-run marginal cost of adding a unit of capacity is less than the average cost of adding a unit of capacity. Thus, if all customers were to pay rates that are equal to long-run marginal cost, those rates generally would be less than the average cost of providing service and the pipeline would be unable to recover its overall costs.

Nevertheless, there are many circumstances in which it is efficient to set rates equal to long-run marginal cost. For example, if a particular customer is willing and able to pay the long-run marginal cost of providing the service, but does not value the service sufficiently to pay the pipeline's average cost of providing service, it may be efficient to provide that customer with a rate equal to long-run marginal cost. Similarly, it is efficient to expand existing capacity in order to serve any customers that are willing to pay a rate that is at least equal to the long-run marginal cost of providing the additional units of service.

1.2.3. Common, Joint and Inseparable Costs

Q25. What are "common" costs in the context of pipeline services?

A. Common costs occur when multiple customers are served, or multiple services are provided, by using the same facilities. In addition, "common" costs can be incurred to provide service to various customers in different proportions.

Some common costs are simply costs of operating a system and are relatively fixed, regardless of the number of customers or the amount of service provided. These types of common costs cannot be exclusively and directly assigned to specific customers or service classes based on a rigorous examination of cost causation. Illustrative of such common costs are the costs for an office building (ownership or rental) that houses a pipeline company. Even many purely operational assets or systems (communications, safety, etc.) are difficult to assign directly to individual customers or services. Such common costs support activities that generally benefit multiple customers, often in a manner that is unrelated to their respective usage levels, and also relatively unrelated to the number of customers. For example, once a company has established a headquarters, staff and computer systems for 50 customers, the costs of these administrative functions will increase very little, if at all, as the company takes on additional customers or increases its throughput. Both the total costs and the average costs per unit for administrative overheads are usually significant; however, the *marginal* cost per unit is generally very low for a pipeline. Thus, because these types of common costs generally cannot be identified as being caused by any *particular* customer or class of customers, fully allocated or distributed costing methodologies can differ materially in their treatment of those common costs that are essentially fixed in both the short run and the long run.

A second type of common costs are those common costs that do vary, at least in the long run, with respect to the amount of service required by an individual customer. Transmission costs related to pipeline capacity are an example of this type of common cost. For example, Customer A may require 60 percent of the capacity on a given pipeline segment during a period while Customer B requires 40 percent of the capacity on that pipeline segment during the same period. Alternatively, Customer A may use only 20 percent of the pipeline during a period when Customer B uses 80 percent. In either case it is possible to say that some portion of the costs are "caused" by A's usage of the facilities, and another portion of the costs are "caused" by B's usage of the facilities.[1] In the long run the facilities are sized and maintained in order to provide capacity to serve both customers so that, from a cost perspective, it can be said that a portion of these common costs can be attributed directly to each customer individually.

Common costs associated with transmission facilities are often allocated to each customer according to the customer's relative usage or firm capacity rights. This method of identifying and assigning responsibility for common costs is relatively straightforward and uncontroversial when there are constant returns to scale (i.e., there are neither economies of scale, nor dis-economies of scale) so that the average cost per unit is also equal to the marginal cost per unit.[2]

However, when there are economies of scale present, as there are with pipelines, it is not necessarily clear as to *how much* of the costs are *caused* by any individual customer. For example, suppose that a pipeline can be constructed for $100 to provide 100 units of service solely for Customer A; and another pipeline also can be constructed for $100 to provide 100 units of service for Customer B. In this example, it would cost $1 per unit ($200/200 units) to provide service to each customer using separate pipelines. Also suppose that an alternative approach

[1] See, for example, A. Kahn, *The Economics of Regulation, Volume I*, page 79: "If services produced in common are to have separate marginal production costs it must be possible to vary their proportions. … If then the proportions are effectively (that is, economically) variable, one can unequivocally identify as the marginal cost of any one product the addition to the total cost of the joint production process occasioned by increasing the output of that one product, while leaving the output of the others unchanged"

[2] For example, when there are constant returns to scale for a particular facility a 50 percent increase in capacity will require a 50 percent increase in costs. In other words, a percentage change in capacity causes costs to change by the same proportion. In contrast, economies of scale are present when a 50 percent increase in capacity can be accomplished by incurring an increase in costs of only 25 percent. Dis-economies of scale occur when a 50 percent increase in capacity is associated with a 75 percent increase in costs.

would be to serve both customers in common by installing a single, large pipeline that could provide 200 units of service for $150. The average cost of providing service from a common pipeline would be 75¢ per unit ($150/200). The two customers can be served by a single pipeline at a lower average cost per unit (75¢ instead of $1.00) because there are economies of scale.

In the presence of economies of scale, the cost of providing service to any particular customer cannot be precisely determined. In analyzing cost causation we could assume that the cost incurred to provide 100 units of service to Customer A is $100, or $1 per unit, because that is the *stand-alone* cost that would be incurred to serve Customer A alone. With this assumption, the *incremental* cost of adding enough capacity to also provide 100 units of service for Customer B is only $50, or 50¢ per unit. In other words, Customer B is causally responsible for only $50 of the costs and the pipeline could recover all costs caused by Customer B by charging Customer B a rate equal to only 50¢. Although this analysis is technically correct, in the absence of additional information an analyst could just as easily flip the analysis and treat Customer B as the first customer – responsible for $100 of the cost – and conclude that the incremental cost of serving Customer A is only 50¢ per unit. Indeed, both analyses are correct, but the pipeline cannot recover its overall costs unless it can collect an average of 75¢ per unit.

Q26. Are there clear and unambiguous dividing lines between costs that are "common" costs and those that are not?

A. Typically not. By illustration, a gas pipeline company generally operates facilities configurations that are highly integrated. Few customers are served solely and exclusively by many specific facilities, assets or expenditures. Instead, groups of facilities generally operate together to serve all or groups of customers, depending on the facts and circumstances. Therefore, pipeline costs are generally "functionalized" (grouped as among their various operational functions) and then even further divided before such resulting baskets of classified costs are assigned to services or classes of service.

Q27. What are "joint" costs?

A. Joint costs occur when costs that are incurred to provide one service, or to serve one customer, allow the company to provide other services, or services to other customers, as a by-product of providing the first service. Joint costs are distinguishable from common costs because joint costs allow additional services to be offered in relatively fixed proportions. For example, shepherds produce both mutton and wool from a grown sheep, and cotton growers produce cotton and cotton seed oil from the same plant. In other words, when they set out to produce one product (e.g., mutton or cotton) they also produce some other valuable product (e.g. wool or cotton seed oil) as a by-product.

When joint costs are present, it is impossible to determine the cost of producing a particular product solely by reference to production cost characteristics. Instead, demand and market-value characteristics become pre-eminent. For example, for the shepherd the net cost of producing mutton is reduced by whatever amount the shepherd can get by selling the wool by-product. On the other hand, the net cost of producing wool is reduced by whatever amount the shepherd can get by selling mutton in the market. Similarly, for the cotton grower the cost of producing cotton is reduced by the amount that can be obtained by selling cotton seed oil in the market. And, on the other side of the coin, the cost of producing cotton seed oil is reduced by the market value of the associated cotton. In both examples, the total cost of raising sheep or growing cotton does not tell us the cost of growing any particular one of the products that are produced. Instead, the "cost" of producing any single product depends upon the demand for, and the value of, the associated by-product.[3]

Q28. How do joint costs enter into the process of determining pipeline costs?

A. Perhaps the most important joint cost characteristic for pipelines occurs because construction of sufficient capacity to provide firm service during peak periods often also produces capacity that could be sold as interruptible service during off-peak periods. Thus, the "cost" associated with peak firm service may be offset by the value (or revenues) associated with off-peak interruptible services.[4] At the same time, the "costs" of providing interruptible services could be reduced by the value (or revenues) derived from selling firm capacity. As a general matter, regulated pipelines are often encouraged within certain bounds to maximize the incremental revenues obtained from interruptible service so as to offset the "costs" caused by firm services.

Another joint cost can occur on a pipeline to the extent that it is able to make deliveries to various locations through displacement at a far lower cost than

---

[3] See for example, A.E. Kahn, *The Economics of Regulation, Volume I*, page 134: "Joint services do not have separable production costs. And … the joint costs *must* be distributed between them … on the basis of the relative intensities and elasticities of the separate demands." (Emphasis in the original).

[4] The analysis of joint costs and appropriate rates is more complicated in situations where a customer is able to substitute interruptible service for firm service and still retain essentially the same reliability as firm service.

the pipeline would incur to construct facilities to make physical deliveries between all points on the system. The use of displacement deliveries reduces the correlation between the cost of providing transportation between two points and the distance between those points. Moreover, the appropriate portion of joint costs to attribute to any particular transportation delivery should be determined by the relative value of the displacement deliveries at each point on the system.

Q29. What are "inseparable" costs?

A. Costs that are required to provide a single service or product are "inseparable" when the expenditure for one of the required inputs of production has little or no productive value without expenditures for other required inputs. This is a concept that is not in the economic literature, but it is an important cost concept that applies to the relatively unique way that NGTL has split the rates and commercial contracts for transportation service into separate receipt and delivery components. The concept of inseparable costs is particularly relevant to pipelines or other transportation companies.

For example, a parcel service can buy trucks and gasoline, and hire a driver to come to the Board's offices to pick up packages, but those expenditures have no value if the parcel service tells the driver to go off-duty once the package is picked up and placed in the truck. By letting the driver go off duty as soon as the package is picked up, the company can avoid incurring any further wages for the service and by leaving the truck parked in front of the Board's offices it can also avoid additional costs of gasoline and wear-and-tear on the truck. But all of the expenditure to pick up the Board's package will have been wasted unless the parcel service incurs the additional costs required to deliver the packages to the destination that the Board requests. In this sense, costs required to pick up the package are inseparable from costs required to deliver the package: the costs of pickup and delivery are incurred to provide a single service.

Q30. How are inseparable costs incurred in the gas pipeline industry?

A. In the pipeline industry, costs incurred to connect gas to a receipt point have no value unless additional costs are incurred to take the gas to a delivery point requested by the customer. Most pipelines provide gas transportation service as a single transaction under a single contract, because transportation is a single service. The entire cost of transportation from receipt to delivery point normally is paid by a single party such as:

- a producer or other party at a receipt point;
- an end-user at a delivery point;
- a marketer;
- a local distribution company; or
- some other type of shipper.

The reason that pipelines normally charge a single shipper the entire transportation cost is that the transportation from receipt to a delivery point is a single service. The prices at which gas is exchanged between producers, marketers, LDCs and end users is undoubtedly affected by which party pays for transportation, but the pipeline normally provides transportation from receipt to delivery point as a single service that is purchased by a single shipper. How the buyers and sellers of gas explicitly or implicitly divide the transportation costs among themselves normally is not a part of the pipeline's service and rate structure.

NGTL, and only a few other pipelines that I am aware of, offer a rate schedule that splits the rate for a single transportation service into a receipt component and a delivery component. This practice explicitly splits the cost of transportation between two parties and also allows enormous flexibility and liquidity to operate on the Alberta System. However, from a cost attribution stand-point, the receipt and delivery components of the rate structure are inseparable costs of providing a single transportation service.

1.2.4. The Bounds of Reasonable Rates (Marginal and Stand-alone Costs)

Q31. Why is the difference between marginal costs and average costs per unit relevant for calculating the cost of serving particular customers or groups?

A. From the standpoint of economic analysis of common costs, only those costs that are caused by the marginal addition of a customer or unit of output can be specifically identified as being the cost of serving that customer or providing that unit of output. Thus, in the example of common transmission costs in the preceding section, the long-run marginal cost of providing transmission facilities for any particular customer would be only 50¢ per unit, and each customer also would have a stand-alone cost of $1.00 per unit if the other customer were not available to provide economies of scale. This means that there is a *range* of common costs between 50¢ and $1.00 that could be economically ascribed to each customer. Within that range are the common costs that cannot be causally assigned specifically to one customer or the other. Depending on the units of measurement that are used, a fully-allocated cost study could assign 75¢ to each customer, which is the average cost of the transmission component of service, or it could assign 50¢ to one customer and $1.00 to the other customer and, purely from a long-run marginal cost standpoint, still have an economically reasonable allocation of costs to each customer group.[5] The amount of unattributable costs that are allocated or assigned to a particular customer or service can depend upon many factors, including the relative elasticity of demand that various customers or services are perceived to have.[6]

1.2.5. The Role of Demand Elasticity in Costing and Ratemaking

Q32. How does demand elasticity affect the determination of costs and ratemaking?

A. As the previous sections discussed, the economically efficient allocation of costs to particular customers or groups of customers often depends upon the level of demand, demand elasticity, or the value that various customers place on a particular pipeline's service. In addition, when joint costs are considered, the "costs" attributable to any one of the by-products produced by jointly-incurred costs depend upon the relative market values of the products.

Most ratemaking for regulated entities starts with an underlying premise that the regulated entity has a monopoly or some degree of market power for a large portion of its business and that the elasticity of demand for its services is

[5] Moreover, if the pipeline is in a period of excess capacity, it could be economically reasonable to temporarily allocate or assign costs on a *short-run* marginal cost basis to some customers until such time as demand grows such that the capacity has a higher value.

[6] Note that it is difficult, if not impossible, to measure a precise value for the demand elasticity of particular customers, but it is often easy to ascertain that a particular customer or group will discontinue or greatly curtail use when rates get above a certain general level, while other customers might withstand significantly higher rates before they reduce usage by a significant amount.

very low.[7] Consequently, rates based on fully-allocated costs that essentially assign to all customers the same average costs per unit (depending upon the factors and measurable customer characteristics that tend to cause costs to vary) can be a viable, fair and efficient means for assigning unallocable costs. However, when a pipeline faces competition from alternative actual and potential pipelines, as does NGTL, the demand elasticity faced by the pipeline can increase substantially and a fundamental reassessment of how unallocable costs are assigned or allocated among the various customers may be required. A fully-allocated cost study provides very little useful information concerning the actual costs "caused" by any particular customers, and in the presence of competition such a study can be especially ill-suited for determining the most efficient method to use in allocating or assigning those costs that cannot be attributed to a particular customer or group of customers.

Q33. What role does demand elasticity play in determining an appropriate allocation of costs?

A. When a pipeline can attract additional business by reducing its rate below average costs, while still collecting rates that exceed the marginal cost of providing the additional service, the company and, in a regulated setting, the other customers will be better off if the pipeline reduces its rates so as to attract the additional business. The Board has already dealt with this concept on many occasions with regard to "load retention" or "non-standard" rates that have been provided for

[7] In fact, for a pipeline with a strong monopoly the demand for its services is a "derived demand" that generally is very low because the demand for the pipeline's transportation services is a direct function of the end-use demand for the delivered product (i.e., natural gas).

specific rate-sensitive customers or groups of rate-sensitive customers without benefit of a specific allocation of the pipeline's costs. However, if some form of cost allocation study is required, efficiency generally can be promoted by considering demand elasticity in choosing among alternative cost allocation methodologies that might all be deemed to be within the range of causally-attributed costs.

Q34. Is this conclusion supported by economic and ratemaking theory?

A. Yes. For example, in his treatise *The Economics of Regulation*, Professor Alfred Kahn observes that:

> The basic defect of full cost distributions as the basis for pricing is, then, that they ignore the pervasive discrepancies between marginal and average cost. And, as this chapter has demonstrated, those discrepancies may require prices that take into account not just the costs but also the elasticities of demand of the various categories of service if the company is to recover its total costs. Whenever there is some separable portion of the demand sufficiently elastic that a rate below fully-distributed costs for it would add more to total revenue than to total costs, any insistence that each service or group of patrons pay their fully allocated costs would be self-defeating. It would force the firm to charge a price that would result in its turning away business that would have covered its marginal costs – in other words, would prevent it from obtaining from customers with an elastic demand the maximum possible contribution to overheads. Thus, under the guise of ensuring a fair distribution of common costs and preventing undue discrimination, it would be serving the interests neither of the patrons who would be prepared to take additional quantities if prices were closer to marginal costs, nor of the customers with the more inelastic demands. [footnote omitted][8]

Thus, a cost allocation study can provide a starting point from which final rates may deviate for reasons of demand elasticity (or other considerations), but

[8] *Kahn*, at page 155.

demand elasticities also can be a consideration in determining the services, customer classes, and allocation factors that are employed in a cost allocation study.

1.2.6. Distinction Between Pipeline Costing and Distribution Company Costing

Q35. Do gas LDCs generally approach ratemaking, and the underlying cost study allocations, in the same way as do natural gas pipelines?

A. No. LDCs, both gas and electric, have generally defined their classes of customers/services so as to distinguish among *types* of customers and/or end users. By illustration, a typical LDC rate structure may distinguish between residential, commercial and industrial end-users, with each of those major categories being further subdivided (e.g., the residential service category may be divided to distinguish between detached houses with discrete meters, and multi-family buildings with a single meter; the commercial and industrial customer classes may have further subdivisions of size or customer category – e.g., schools, hospitals, government, etc.) Gas pipelines rarely group their services in this customer/end-use manner. Instead, the characteristics and quality of the services provided are generally the key service determinant (firm, interruptible, distance of haul, etc.) for making rates, not the type of downstream customer or the nature of their end use.

One important reason for the rate class and cost allocation distinctions between pipelines and LDCs is that pipelines sell firm transportation service as a right to use a certain fixed, known amount of capacity (or contract quantity) while LDCs have large portions of their load taking either firm transportation or gas sales service on a “full requirements” basis. This means that many of the costs incurred by LDCs to ensure reliable firm service are generally determined by the actual usage characteristics of individual customers or customer groups, and the LDCs. (To some degree, NGTL adds capacity at various points on its networked system based on localized usage characteristics that cannot be ascribed to a single customer or contract, but this type of capacity expansion is still guided by the level of contracts in an area in addition to usage characteristics).

NGTL also is distinguishable from most LDCs in that it separates the transportation service into receipt and delivery rate and contract components. Few, if any, LDCs sell receipt rights that are disembodied from delivery rights.

1.3 Evaluation of NGTL's Fully-Allocated Cost Studies

Q36. What are the service choices for transporting gas on NGTL's Alberta System?

A. Currently, NGTL offers three firm service choices for transporting natural gas on the Alberta System.

First, shippers can use the FT-R service to put gas into the Alberta pipeline system at a discrete receipt point where that gas enters the NIT market, and then is sold to an ex-Alberta customer. That customer then pays the FT-D toll associated with the longer distance that, on average, is required to transport gas to export delivery points.

Second, shippers can use the FT-R service to put gas into the Alberta pipeline system at a discrete receipt point where that gas enters the NIT market and is transported to the doorstep of nearby intra-Alberta delivery points. There it can be sold to customers who pay the FT-A charge to cover the balance of the full-haul intra-Alberta transportation charge.

Third, intra-Alberta shippers can procure FT-P service, thereby foregoing the benefits of the NIT mechanism, but paying their transmission charges on a basis that tracks the particulars of their own points-to-point transaction.

Q37. How has NGTL allocated or assigned costs in the cost of service study that uses the Existing Methodology for conducting a cost-of-service study and the six Alternative cost-of-service study methodologies presented in this Phase 2 GRA Application?

A. In each instance, NGTL has functionalized the costs into metering, transmission, and general and administrative ("G&A") overheads. It then allocated or assigned G&A overheads to the Metering or Transmission functions. The total costs associated with or allocated to Metering and Transmission functions are then allocated or assigned to primary services.[9] The cost allocation and assignment methods utilized in NGTL's studies are summarized in Appendix 2D-2.

1.3.1. Standards for evaluating a Fully Allocated Cost of Service Study (Cost reflection and Bonbright Principles)

Q38. How should one evaluate a fully-allocated cost of service study?

A. In general terms there are two primary questions to consider:

1. Does the study reasonably reflect the relative costs of providing different services to different customer groups?
2. Will the study produce rates that meet the commonly recognized criteria of a sound rate structure?

I use these standards to evaluate NGTL's cost of service methodologies.

[9] For purposes of this study, "primary services" are those services that receive a direct allocation or assignment of costs. In contrast, "secondary services" are services for which a rate is derived based on relationships to the primary service rates. The projected revenues from the secondary services are then credited to the revenue requirement so as to offset a portion of the costs that are allocated to, and recovered from, the primary services.

Q39. What factors are considered in determining whether a fully-allocated cost-of-service methodology reasonably reflects the costs of providing a particular service or service to particular customers?

A. In distinguishing the costs of providing specific services or serving different customer groups, some of the most important questions to consider are:

(1) whether the level of averaging used to allocate or assign costs is reasonable;

(2) whether functionalization and cost classification is conducted at a reasonable level of detail;

(3) whether there is a sufficient causal relationship between the allocation factors employed and the level of costs required to provide each service, or to serve each customer; and,

(4) whether there are any relevant policy considerations or goals.

Q40. What are the criteria of a sound rate structure for the services that are offered by a regulated company?

A. As a general matter, the following eight criteria of Professor James C. Bonbright have remained viable and resilient over the four decades since their first publication (*Principles of Public Utility Rates*, 1961, page 291):

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretations.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amount of use.

Q41. Are the foregoing ratemaking objectives all consistent with one another?

A. No, they need not be. By illustration, a given rate structure that embodies the ultimate in rate *stability* could soon become unacceptable with respect to other criteria, e.g., achieving a fair rate of return, or relative fairness among customer classes. Thus, there can be tensions and conflict among these rate criteria, based on the specific facts and circumstances of any company.

Q42. Does each of these foregoing rate criteria carry equal importance and weight?

A. No. I agree with Professor Bonbright's assessment (page 292) that the rate criteria designated as items (3), (6) and (8) above are the three primary ones. Many rate design and rate structure disputes revolve around the tensions that can arise between items (6) and (8), i.e., the potential conflict between standards of "fairness" and "efficiency" as among the affected customer classes. From these potential conflicts arise many current rate debates, such as the proper nature and form(s) of marginal-cost pricing. However, a set of rates that putatively meet all of the other rate criteria, but that jeopardizes the basic viability of the operation and its ability to render service cannot be considered to be reasonable.

Q43. How is your evaluation of NGTL's methodologies organized?

A. In the next three sub-sections I discuss each of the functional cost categories (administrative and general overheads, metering, and transmission), the factors that can cause the costs of each function to vary, and some of the cost allocation methods that might be used to approximate the manner in which costs vary. Then, I evaluate NGTL's Existing Methodology for conducting a cost-of-service study and each of the alternative cost-of-service study methodologies presented in NGTL's evidence. Finally, I present a summary of my evaluations.

1.3.2. Allocation of Administrative and General Overheads

Q44. How are administrative and general ("A&G") overhead costs allocated when they cannot be directly attributed to any one service or customer group?

A. A variety of techniques have been used to allocate A&G costs in various circumstances. A common method, and the one that is used by NGTL in its analyses, is to allocate A&G using allocation factors that are based on the level of facilities-related costs allocated to each service or customer group.

Another common approach is to use allocation factors that are based on records of direct labor costs expended on maintenance for facilities used by each class or service. That approach is used by some retail utilities that have a significant portion of facilities that can be cleanly delineated as being used solely for the benefit of specific classes of customers, and that also keep maintenance records in a form that identifies the direct labor costs that are expended to maintain facilities used solely by each particular service or customer class. In the case of the Alberta System, the direct labor costs that can be directly attributable to any single service is a very small portion of the total direct labor costs because the vast majority of transmission and metering facilities are used to provide multiple services on a common, joint and/or inseparable basis. Thus, an A&G allocator based on direct labor would not necessarily be a reasonable method for the Alberta System. For a pipeline like the Alberta System, the proportion of facilities' costs allocated to each service provides a reasonable method for allocating A&G because there is likely to be a general relationship between the amount of facilities on a pipeline and the level of its A&G costs, and there is not another method that obviously would be superior to facilities' costs as an A&G allocator for the Alberta System.

1.3.3. Allocation of Metering Costs

Q45. Would you describe how the level of averaging might be considered in selecting a method for allocating metering costs for a pipeline operation?

A. Metering costs might be allocated based on the number of meters, which implicitly allocates the same average cost per meter to every class or service. The costs actually incurred to install each individual meter usually vary widely and depend upon when the meter was installed, the location where it is installed, the capacity and/or capabilities of the meter, and possibly other issues surrounding the purchase and installation of the meter.

At one level of detail, each customer could be charged a rate that reflects the specific costs that were incurred to install the meter used by that customer. This level of detail requires very detailed record-keeping and precludes the ability to provide a stated tariff rate. A decision to use this level of detail also involves issues of fairness as between customers since the vintage, and therefore the original cost and net book value, of facilities can be different based solely upon when the meter was installed.

At a somewhat higher level of detail, one might analyze the average cost of meters for a particular class of customers or service. If the average cost of meters is significantly different for each class or service, and the costs for individuals within the class or service group are sufficiently alike, metering costs could be allocated to each class or service based on some ratio that reflects the average cost of meters for that group.

However, if no significant differences exist, or the costs involved are not large, or there are policy reasons to not adopt a distinction among the metering costs for each group, an overall average cost per meter might be appropriate. Thus, the level of averaging to adopt is an important decision for which there is not necessarily an obvious answer; there can be many possible answers depending upon the circumstances and intended goals.

Q46. How can the weighting of cost characteristics affect the type of factor to use for allocating metering costs?

A. The prior example discussed the possibility of allocating metering costs based on the number of customers. It may be that the cost of each individual meter depends in part on the capacity of the meter installed. In that case, one might allocate the metering costs based on the total contract demand ("CD") associated with each class or service, thereby implicitly using the average cost of metering per unit of CD.

However, metering costs rarely would be directly proportional to the customers' CD. There are typically fixed costs associated with installing any meter that are incurred regardless of the capacity of the meter. In addition, there may be economies or dis-economies of scale so that, for example, a meter twice as large as another might cost only 1.5 times as much. In this case the average cost per unit of CD may not provide a particularly good indicator of the "cost" of providing meters to different customer groups and, thus, an allocator might be developed based on some combination of number of meters and the CD of the customers in the group.

Q47. How can the usage characteristics of customers affect the type of factor to use for allocating metering costs?

A. In addition to the possibility of fixed costs and/or economies of scale in metering, the CD of the customers may not correspond well to the metering costs of a group because the group uses a large amount of interruptible service or because contracts at a number of points are less than the design capacity of those points.

Moreover, if there is a wide variation in the capacity factors of different customers and the rates that are developed from the allocation factors attempt to collect fixed costs on a commodity basis, high load factor customers within a class or service group would pay more than the average cost per meter, while low load factor customers would pay less than the average cost per meter. This raises the policy question as to whether the metering costs avoided by low load factor customers should be paid by other customers *within the same class*, or whether it would be more reasonable and equitable to either: (i) change the toll design so that metering costs are recovered in a manner that is not dependent upon capacity factor; or (ii) allocate metering costs to a broader group of classes and services that would all share in making up any shortfall associated with the usage of low load factor customers.

Q48. Is there a single best method that can be used for allocating metering costs on all pipelines?

A. As the foregoing discussion indicated, there can be different levels of averaging employed. Some factors that might be employed include average cost per meter, average cost per unit of CD, average cost per unit of volume transported, or some combination of these approaches. In addition, there are numerous approaches that might consider marginal costs or other factors in allocating metering costs that were not discussed above. Many considerations can go into selection of the appropriate method for allocating metering costs for a particular pipeline depending upon its particular facts, circumstances, and policy considerations. Because there is never a single method that is best for allocating or approximating costs in all circumstances, any cost allocation approach must be evaluated in terms of whether it provides a *reasonable* method for assigning costs to individual services or customer groups under particular circumstances.

Q49. How has NGTL allocated metering costs?

A. Metering costs are allocated to the various services and rate components using an average cost per Mcf of gas that was metered during the base period. This results in an average cost of 1.42¢ per Mcf.

Q50. What is your evaluation of this method of allocating metering costs?

A. The level of averaging employed in this approach is reasonable for NGTL's current circumstances and services. Although sub-groups may be found that have differing average costs of metering per unit, the concept of an overall average cost of all meters is consistent with the nature of the services where every transportation haul requires metering at both the receipt and delivery points. Averaging the system-wide metering costs causes the receipt and delivery components of the single transportation service to split the metering costs equally and is a reasonable method of sharing metering costs. Because the perception of fairness is a consideration in splitting metering costs between different groups, one factor in my evaluation of this approach is prior customer and Board acceptance. This method has been shown to be accepted as reasonably fair in its acceptance by the customers in the past. In addition, the Board recognized this broad acceptance in Decision 2004-097 and also recognized that there was wide variability of metering costs within sub-groups of customers that reduces the significance of allocating different metering costs to specific sub-groups of customers.[10]

By allocating metering costs based on the volume of gas metered on the system, low-load factor services receive a lower allocation of costs than might be appropriate when one considers that metering costs generally vary with respect to the number of customers, but that metering costs are fixed with respect to volumes of throughput. This effect is compounded by the fact that the FT-A rate is collected on a commodity (or volumetric) basis that may allow shippers to avoid paying for fixed metering facilities during times when they do not use the facilities, or when they use the facilities at a low load factor. In addition, it would be appropriate to allocate some portion of metering costs to storage service since meters are required as an integral part of that service.

On the other hand, allocation of metering costs based on volumes may create rates that roughly reflect the relative costs of meters used by various sub-

[10] EUB Decision 2004-097, October 26, 2004 in *NOVA Gas Transmission, Ltd., 2004 GRA Phase II*, page 18.

components of the transportation service. For example, customers with a high CD generally will require larger, more costly meters. NGTL's method of allocating costs and designing rates to recover the metering costs from FT-R and FT-D customers on a demand basis will charge more total dollars for meters to customers with higher CD and, thus, roughly reflect the relative costs of meters for each customer group. This rough approximation may also hold true for FT-A customers to the extent that total throughput is related to the size and cost of meters used by individual customers. Thus, a size-of-meter cost dimension is reflected in this method of allocation and cost recovery, but other factors such as load factor or economies of scale are not well represented.

This emphasis of one cost factor over others is not a significant issue if the policy goal is to share metering costs equally among the different rate and contract components of transportation service. However, some of the price signals that might be provided to encourage efficient construction in the long run and/or efficient usage of facilities in the short run may be dampened by excluding these other factors from the allocation factor calculation. Because NGTL layers accountability provisions on top of the cost allocation and rate design, the efficacy of price signals for promoting efficient construction of facilities should not be evaluated in isolation. Instead, the accountability provisions for new facilities augments the price signals provided by the cost allocation and rate design.

With respect to price signals for efficient *usage* of facilities that have already been constructed, the FT-A rate has some drawbacks because it collects fixed metering costs on a volumetric basis if no Minimum Annual Volume

("MAV") charge is in place, or if the volumes exceed the MAV. In those circumstances FT-A customers face a price signal that charges an additional metering cost every time they contemplate the nomination of additional gas volumes, even though there is no variable cost, or short-run marginal cost, of metering once the meter is in place. Thus, a volumetric toll design could discourage additional usage and consumption that in fact would be efficient.

Q51. What do you conclude from your evaluation of NGTL's metering costs?

A. NGTL's existing method of allocating metering costs reasonably satisfies Bonbright's principles (1), (2), (3), (5) and (6) that deal with practicality, feasibility, efficacy, stability and fairness. In addition, the Existing Methodology for allocating metering costs is reasonable with regard to long run price signals for construction of new facilities when NGTL's accountability provisions are considered. The recovery of fixed FT-A costs on a commodity basis may discourage efficient short-run usage or consumption at the margin, but that also is not a major problem at the current level of the FT-A rate. Thus, Bonbright's principle (8), discouraging wasteful use of service while promoting all justified types and amounts of use, is reasonably satisfied for metering costs under the Existing Methodology for conducting a cost-of-service study. Similarly, although the FT-A rate collects fixed metering costs on a commodity basis, the existing allocation and rate design would not jeopardize the satisfaction of Bonbright's principle (4), revenue stability, because intra-Alberta metering costs are a small part of NGTL's total revenue requirement and, in many instances, the MAV component of the FCS charge ensures that these costs are collected regardless of throughput. Finally, because the method of allocating metering costs reflects a judgment that these costs should be shared equally among NGTL's customers, and the fact that it roughly reflects the size dimension of metering costs, the Board can reasonably conclude that there is no undue discrimination in the allocation of metering costs and therefore that Bonbright's principle (7) is satisfied.

1.3.4. Allocation of Transmission Costs

Q52. Is the allocation of transmission costs generally more complicated than the allocation of metering costs?

A. Yes. A meter generally is used to provide a specific service to a specific identifiable customer or group of customers. In contrast, if transmission facilities are generally used to provide multiple services to many different customers, the transmission facilities will have common and joint cost characteristics that make it impossible to determine how much of the total transmission costs are required to provide any particular service or to provide service to any particular customer.

Q53. What role does averaging play in the allocation of pipeline transmission costs?

A. Because it generally is impossible to determine the level of transmission costs that are caused by any one customer or transportation shipment, it is common to develop services or customer classes around characteristics that very generally reflect service/cost differences, and then allocate costs to those services or customer classes in a way that reflects the *average* costs for the services and customer classes established.

For example, if distance is incorporated into the toll design, it is common to establish geographical rate zones and implicitly assign costs as if all customers who use a zone ship the same average distance within the zone. Distance also sometimes is reflected by establishing distance bands and then assuming that everyone who ships gas between any two points ships the same average distance and requires transmission facilities that have the same average costs.

In addition, many pipelines ignore the role that pipeline diameter plays in causing transmission costs to vary. In doing so, they allocate costs by implicitly assuming that all pipeline segments have a diameter equal to the average. However, cost differences related to diameter on specific parts of a system can be reflected in a variety of ways that reduce the level of averaging involved.

Similarly, transmission costs on various segments of a pipeline system can be significantly impacted by the level of compression required, but it is relatively unusual to allocate costs to customers and services based the level of compression required. Instead, it is often assumed that all customers on the system, or within a zone or distance band, require the same average costs of compression per Mcf, or per Mcf-mile. But it also is possible to reduce the level of averaging by directly assigning, or disproportionately allocating, compression costs to particular customers or services in some situations.

Most transmission cost allocation approaches ignore the vintage and remaining net book value of particular transmission segments; thereby implicitly assuming that all transmission assets have the same average remaining life, and that the original cost gross book value of all transmission facilities were purchased with funds that had the same average real value (i.e., inflation and/or technological change has not had an effect on the replacement costs of different vintages facilities). However, it is not uncommon for a pipeline to directly assign the net book value of certain facilities to a particular service and price that service on a separate, incremental-cost basis.

Q54. What role does distance between receipt and delivery points play in determining and allocating pipeline transmission costs?

A. For all pipelines, the total miles of pipe is an important factor in determining *total* transmission costs. However, there are many situations where the distance between the receipt and delivery points used by particular services or customer groups may not provide a good reflection of the relative transmission costs per unit caused by, or incurred on behalf of, individual services or customer groups.

For example, the distance between receipt and delivery points may not be particularly significant if the pipeline system has economies of scope associated with network characteristics that reduce the correlation between distance and cost. Thus, it is relatively common for pipelines that have receipt points and delivery points spread throughout their system – and that deliver large portions of their gas by using multiple routes, displacement, and/or flow reversals – to adopt postage stamp rates that ignore distance in the allocation of costs.[11]

Similarly, distance may be overwhelmed by diameter and economy of scale effects if a straight line of pipe is designed primarily to serve receipts concentrated at one end of the system and deliveries concentrated at the other end of the system. Although there may be receipt and/or delivery points with relatively small volumes at intermediate points along such a pipeline, a marginal

[11] Although system-wide postage stamp rates can be appropriate for most gas flowing on such a system, there can be special situations where exceptions to the postage stamp rate are required because of special cost characteristics in a particular area, or high demand elasticity due to competition or other factors.

cost analysis would not necessarily be able to determine that there is a significant difference between transmission costs required to serve the large volume, long-haul customers and the small volume, short-haul customers.

For example, suppose the transmission cost of service associated with providing a relatively short, small-diameter pipeline to serve only the short-haul customers is 50¢ per Mcf/d. It may be the case that a pipeline twice as long could be constructed to serve both (i) the small, short-haul market, and (ii) the much larger long-haul market. If the *marginal* cost of constructing additional transmission facilities to also serve the large, long-haul market is only 30¢ per Mcf/d (because of the economies of scale associated with constructing a larger diameter pipe to serve the large, long-haul market), we might conclude that the analysis shows that it costs 50¢ per Mcf/d to serve the short-haul customers and only 30¢ per Mcf/d to serve the long-haul customers. In other words, the relative distance between receipt and delivery points may not provide a strong basis for allocating more transmission costs to long-haul customers than to short-haul customers if the long-haul customers are considered to be the marginal group.

An opposite conclusion might be reached if one were to conduct the analysis by first considering the stand-alone transmission costs to serve only the large, long-haul market, and then determine the marginal costs required to size the transmission facilities so that the pipeline also has capacity to serve the small, short-haul market. Approaching the marginal cost analysis in this way might indicate that it costs 35¢ per Mcf/d to serve the large, long-haul market on a stand-alone basis and the long-run marginal cost of adding transmission facilities to also serve the short-haul market is only 5¢ per Mcf/d.

Q55. When would it be appropriate to treat a particular service or customer as the marginal service or customer?

A. When a clear distinction in the demand elasticity of different services or customers is present, it can be efficient and appropriate to evaluate the costs of providing the most price sensitive services, or service to the most price sensitive customers, from the standpoint that they represent the marginal service or customer. For example, a large difference in the price sensitivity of different services or customers becomes important in cost allocation when one possibly reasonable cost allocation method might cause the most price sensitive customers to avoid or cease using the pipeline's service(s) (or make a major reduction in its use of the service(s)), while another possibly reasonable cost allocation method might attract or retain large amounts of business from the most price sensitive customers. Both of these alternatives assume that usage by customers who are less price sensitive will be relatively unaffected by the selection of an appropriate allocation method. In these circumstances, so long as the most price sensitive customers pay rates that cover long-run marginal costs, it generally will be efficient to evaluate costs by considering the most price sensitive services or customers as being marginal from the standpoint of cost causation and responsibility.

Q56. What does the foregoing discussion mean with regard to the appropriate method to use for allocating transmission costs to particular services or customer groups?

A. When selecting or developing a method for allocating pipeline transmission costs to particular services or groups of customers, there are many factors to consider, including: configuration of facilities, distance, diameter, competition and demand elasticity. All of these factors, and possibly other factors, have an effect on the cost of transmission facilities that is incurred to provide a particular service or service to a particular group of customers. Because there are many ways that transmission costs can be allocated, it is necessary to weigh the importance of various factors.

Q57. What economic characteristics of the Alberta System are most important for allocating transmission costs and designing an appropriate toll structure?

A. Overall, the average rates for transportation services should equal the average costs per unit of providing services in order to provide revenue adequacy. Efficient prices for transportation services also should reasonably reflect the costs of providing individual services.

However, the Alberta System has economies of scale that produce long-run marginal costs that are less than average costs in many instances. Short-run marginal costs also are less than average costs on most parts of the existing system simply because NGTL already has sufficient capacity to serve demand at those locations. In addition, NGTL has substantial network economies of scope in the sense that its integrated system can transport gas between numerous receipt and delivery points at a cost that is far less than the cost of constructing a separate pipeline between each receipt and delivery area in the province. These economies of scope are magnified by the existence of receipt points throughout the province, combined with delivery points throughout the province, that allow NGTL to use displacements and flow reversals to efficiently deliver gas between supply and demand locations that can change daily, seasonally, or permanently from time to time. These economic characteristics are significant because they suggest that: (i) not all customers can receive rates that are equal to marginal cost or NGTL would be unlikely to recover its total costs; and, (ii) a large portion of the costs cannot be precisely assigned to one particular service since the same facilities are used to provide many different services.

Determining the cost of transmission facilities required to provide any particular service, or service to any particular group of customers is particularly difficult under NGTL's contract, rate and service structure because NGTL separates receipt contracts from delivery contracts. Splitting the transportation service into separate components in this way allows a highly liquid and flexible market for natural gas to operate through the NIT system. However, it generally is impossible to say precisely which facilities were used and what costs were incurred to provide any particular transportation shipment on the Alberta System because:

(1) the specific receipt point and the specific delivery point used in a NIT transaction are not tied together and identified as the origination and destination points for the gas shipment in a NIT transaction;

(2) the gas often does not physically flow on a transportation path that goes from the specific receipt point to the specific delivery point that is involved in the transaction; and,

(3) NGTL's service structure and the NIT market effectively allow the receipt and delivery point pairs used in transportation shipments a great deal of flexibility to change on a continuous basis.

As a consequence of these characteristics of the NGTL contract, rate and service structure, every receipt point has access to every delivery point on the system and every delivery point has access to every receipt point on the system. Thus, on a service and contractual basis, all shippers generally have access to the same transportation facilities, unless they elect to take FT-P service.

Q58. Are there other characteristics of the Alberta System that are important for allocating transmission costs?

A. Yes. The Alberta System consists of an unusually wide array of pipeline diameters primarily because it collects gas from many receipt points throughout Alberta that vary greatly in their capacity requirements. In addition, on many portions of the system NGTL is able to use relatively expensive small diameter pipelines to aggregate gas from numerous receipt points and achieve tremendous economies of scale by using larger diameter pipelines for portions of the transportation haul. Thus, there can be a large difference in costs as a result of the volume of gas and the economies of scale that can be achieved in particular situations. Many pipelines ignore or minimize the role of diameter in transmission costs because the diameters of their various pipeline facilities tend to be much more homogeneous than those of NGTL and/or because they face far less competition than NGTL.

In addition, although there are significant network characteristics on the Alberta System that reduce the importance of distance in determining overall transportation costs, a significant majority of the gas volumes flowing on the Alberta System are delivered to three border delivery points in the southern part of the province. This means that distance to those border points is a significant determinant of the transmission costs for a majority of the gas on the system.

In contrast, because intra-Alberta deliveries occur throughout the Alberta System, distance to the border points is not a strong determinant of *intra-Alberta* transmission costs. In addition, because network characteristics are present, the distance between contractual receipt and delivery points has a diminished relationship to the distance of physical flows required to provide any given FT-R/FT-A transportation service combination. The significance of distance as a determinant of intra-Alberta transportation costs is much stronger when a customer takes FT-P service because the distance of physical flows generally corresponds more closely to the distance of contractual flows under the points-to-point service. When a customer takes FT-P service, that service greatly limits the portions of the Alberta System which (s)he uses on a contractual basis, thereby limiting the differences between contractual flows and physical flows.

1.4 Evaluation of NGTL's Existing Allocation Methodology

Q59. Have you evaluated NGTL's Existing Methodology for conducting a cost-of-service study and the Alternative methodologies with respect to the principles of a reasonable rate structure?

A. Yes. These evaluations are discussed below. Because each alternative examined utilizes the same method of allocating metering costs that I described and evaluated in section 1.3.3, the evaluations in this section will not repeat the metering evaluation but, instead, will focus primarily on the allocation of transmission costs and the overall impact on rates and rate relationships.

Q60. What is your understanding of the way that NGTL: (a) apportions transmission system costs between the intra-Alberta and ex-Alberta transportation, services; (b) splits the transmission costs allocated to intra-Alberta transportation service between receipt and delivery components; and (c) splits the transmission costs allocated to the generally longer export transportation service between receipt and delivery components?

A. NGTL allocates transmission costs between intra-Alberta and ex-Alberta transportation services so as to include an average transmission cost component in the total "full-haul" rate for intra-Alberta transportation that is 50 percent of the average transmission costs allocated to the total ex-Alberta "full-haul" transportation services. This allocation factor based on 50 percent serves two purposes: (i) it roughly corresponds to the ratio of the average distance of physical flows used to provide intra-Alberta transportation, as compared with the average distance of physical flows used to provide export transportation; and, (ii) it accommodates a 50-50 split of transmission costs between receipt and delivery components of the export transportation rate.

As a result of historical practice and procedure for NGTL, the first leg of transportation, between receipt points and the NIT pool or the doorstep of intra-Alberta delivery points, is referred to as "receipt" service. The second legs of transportation are referred to as: "export delivery" service between the NIT pool and the generally more distant border export points; and "intra-Alberta delivery" service between the NIT pool and the generally closer intra-Alberta delivery points.

Service for transportation on these foregoing transportation elements or legs is separated, both contractually and for ratemaking purposes, into a receipt component, an export delivery component, and an intra-Alberta delivery component. By simultaneously allocating to intra-Alberta transportation 50 percent of the transmission costs allocated to export transportation, and also splitting export transmission costs 50-50 between receipt and delivery components, the transmission costs allocated to intra-Alberta transportation must all be collected in the receipt component of the service in order to satisfy the ratemaking constraints. This use of the same transmission component in the average receipt rate for both intra-Alberta and export transportation, while assigning a 50 percent cost split to the export delivery component, and a 0 percent cost split to the intra-Alberta delivery component, is a functionalized form of "zone-based" and/or distance-sensitive ratemaking. Zone-based or other types of distance-sensitive rates are common on many long-distance pipelines, but the zoning concept has been adapted to the complex nature of the Alberta System and services. The assignment of transmission costs in the Existing cost-of-service methodology also recognizes that transmission costs are inseparable with regard to the receipt and delivery components of transportation service.

Q61. How is the concept of averaging incorporated into the existing rate structure?

A. It is important to recall that until recently NGTL's transportation tolls generally were all set to equal the average cost for the entire system (i.e., a "postage stamp" toll), where transportation to delivery points within Alberta paid a charge that was approximately one-half the level of the charge for deliveries to export points.

This lower charge for local deliveries reflected the fact that, on average, gas transported to intra-Alberta delivery points traveled half the distance required for delivery to export points. With this one exception, distance, economies of scale and other cost characteristics formerly were ignored in establishing postage stamp rates based on two large averages.

However, that large average toll structure became unsustainable once competition was introduced into the Province; largely by proposed export pipelines that would be under NEB jurisdiction. A particularly strong impetus for these proposed export pipelines was the fact that large volumes of gas were paying tolls that reflected NGTL's average costs, but the stand-alone costs of transporting some of those volumes were below the average. Proposals for competing pipelines were not confined to just one area. Instead, such proposals appeared throughout the Province wherever economic characteristics provided transportation costs that would be below the Alberta System's system-wide intra-Alberta and ex-Alberta averages. In these circumstances NGTL was forced to de-average its toll design and develop a design that more closely tracks the transmission costs of providing services between specific points. In recent years, the existing toll structure has met Bonbright's principle (3), revenue adequacy, and it appears to be sustainable for now in the sense that it reduced the incentives to construct uneconomic export pipelines that "cherry picked" those customers who could be served at a cost significantly below the system-wide average cost that was the basis for the prior, postage stamp, toll design.

This background is significant because it also highlights the fact that the existing toll design was developed in response to many competitors, at many locations, which forced NGTL to implement a toll design that more closely reflects costs of providing transportation services throughout the system. This competition highly constrains the ability of NGTL to implement a toll structure that unduly discriminates for or against particular groups of customers or that requires any customers to unfairly cross-subsidize other customers. Thus, Bonbright's principles (6) and (7) should be reasonably satisfied or NGTL will have difficulty recovering its total revenue requirements.

Q62. Does the Existing Methodology for conducting a cost-of-service study reasonably reflect the manner in which transmission costs are incurred on the Alberta System?

A. Yes. Most transportation services on the Alberta System allow customers to buy and sell gas in the NIT market and have gas transported under contracts that separate the receipt and delivery components of the transportation charge. This split-contract structure allows shippers on the system to transact to buy and sell gas with other parties located throughout the entire Alberta System. As a consequence of the flexibility of the split-contract structure, large volumes of gas are delivered on the Alberta System using displacement operations that are far more efficient than constructing numerous separate pipelines to provide each receipt and delivery point with the same level of access to alternative sources, markets and liquidity that the Alberta System provides. Under this type of split-contract, system-wide service, contractual distance is not necessarily a primary determinant of transmission costs. However, because the great majority of gas flows from points throughout the province to a few export points at the southwestern and southeastern borders, the costs of many contractual flows are related in a general way to distance from those export points.

The Existing Methodology for conducting a cost-of-service study provides a reasonable blending of the uncertain distance and broad flexibility of contractual flows in NIT on the one hand, with the known physical flows on the other hand. For example, it reflects distance in the allocation of transmission costs between export transportation and intra-Alberta transportation. The average intra-Alberta total transportation rate is responsible for one-half of the unit transmission costs that are allocated to the average export transportation rate. This 2-1 allocation of transmission costs between export transportation and intra-Alberta transportation is a rough approximation of the distance of haul that has been convenient because it allows the FT-R rate to be used to provide transportation service that includes access to NIT for both intra-Alberta and export volumes, while also maintaining the intuitively appealing equal cost split between the FT-R rate and the FT-D rate components. In addition, because the quantities of gas at particular locations, and the diameter of pipe that can be utilized to serve those locations, is an important determinant of costs, the Existing Methodology for conducting a cost-of-service study also utilizes factors that reflect both distance and the economies of scale associated with larger pipe diameters in designing separate FT-R rates for each receipt point. Because the FT-D rate component is a postage stamp rate out of NIT and not based on distance or diameter, a 50-50 split of transmission costs between FT-R and FT-D for export transportation implicitly gives a 50%

weighting to distance and diameter characteristics related to physical flows, and a 50% weighting to network displacement characteristics and the largely untraceable nature of contract flows.

One consideration of the Existing Methodology appears in the allocation of transmission costs to those intra-Alberta deliveries that are made through the FT-R/FT-A service combination. Because the FT-R component of the rate is developed based on the distance between the receipt point and the Alberta border export points, the FT-R/FT-A full-haul rate can, in many situations, place too much of the transmission cost burden on intra-Alberta transportation service and thereby encourage uneconomic by-pass of the system. NGTL introduced the FT-P service option for intra-Alberta deliveries in order to ensure that intra-Alberta shippers would have a rate and service option that reflects the actual distance between specific intra-Alberta receipt and delivery points. However, in the process of providing a more precise allocation of transmission costs to specific intra-Alberta transportation transactions, the FT-P service requires customers to forego access to the NIT market so that there is a stronger correspondence between their contractual flows and the physical flows required to provide the service.

Another consideration of the existing approach is that there are some costs that might be allocated or directly assigned to FT-X or IT-S service but, as a result of historical practice and industry preference, these services do not pay toll charges under the existing toll design.

Nevertheless, the methods used by NGTL to approximate and reflect factors that affect the level of transmission costs for particular services and customers is a reasonable approach at this time. Thus, it should be considered to satisfy Bonbright's principle (6), fairness, and Bonbright's principle (7), avoidance of undue discrimination.

Q63. In the past it has been suggested that it is inefficient or anti-competitive for NGTL's toll structure to levy all, or most, of the transmission costs of intra-Alberta transportation through charges at the receipt point. Do you agree?

A. No. In fact, that is the normal method of charging for services in many transportation industries and it is a very common method of pricing in many communications industries as well. For example, railroads, trucking companies and postal services routinely recover all of their costs from the shippers at the receipt end, and generally do not charge anything to the party at the delivery end. Other pipelines in Alberta have also used this approach. For example, ATCO Pipelines has a zero delivery charge for gas that ATCO Pipelines delivers to the Alliance and Many Islands export pipelines. Presumably, ATCO Pipelines recovers the full costs of transportation to those export pipelines through the receipt charge. Most people do not pay the postal service or FedEx to take delivery of their mail and packages; instead all of the transportation charges are paid by the shipper who initiates the shipment at the receipt end of the transportation system. This is a common practice in highly competitive industries.

Consequently, since all intra-Alberta delivery volumes will already bear an average FT-R rate loading for the short-haul, first-leg transmission costs, the existing NGTL practice of assessing Alberta users an additional delivery charge that only recovers metering costs continues to be reasonable. Stated alternatively, the gas received by NGTL and transported through NIT to the doorstep of intra-Alberta delivery points *already is responsible* for a proper share of NGTL transmission system costs when shippers pay the NGTL FT-R transportation rate.

There has been a concern that a low FT-A charge may encourage inefficient construction of facilities to attach intra-Alberta delivery customers, but NGTL's accountability provisions and the Board's regulatory policies augment and supplement the long-run price signals for new construction conveyed by the existing level of the FT-A rate. Thus, NGTL's existing cost allocation and toll design approach reasonably satisfies, Bonbright's principle (8), efficiency in discouraging wasteful service.

Q64. What is your evaluation of the Existing Methodology for conducting a cost-of-service study?

A. NGTL's Existing Methodology appropriately reflects the effects that average distance of haul plays in determining transmission costs. Although distance is an important factor in transportation, the use of displacement to accomplish many deliveries on the system and provide system-wide access to customers somewhat diminishes the importance of distance for determining the overall costs of transportation. Allocation of a 2-1 ratio of transmission costs to export versus intra-Alberta transportation is reasonable because it roughly reflects the historical ratio of the average distances of haul for these two services. This is a satisfactory method of allocating these costs because it is impossible to say how much weight distance should receive on the Alberta System. A precise measure of the distance of physical flows does not provide a precise determination of the relative costs of making deliveries when the service provides access to the entire system and, on a contractual/commercial basis, accomplishes many deliveries for the Alberta System using displacement operations. Therefore, basing the allocation on a precise distance of haul calculation will not necessarily provide a more precise determination of relative costs.

For export transportation, the Existing Methodology provides a reasonable balance between the effects of distance on cost and the effects on cost of system-wide access provided by network displacement operations. This balance occurs by virtue of the 50-50 split between (i) the average transmission component of the FT-R receipt component of export transportation rates, which is then designed to reflect distance and diameter cost factors, and (ii) the average transmission component of the FT-D export delivery component of export transportation rates, which is designed on a single system-wide basis. By splitting these two rate components 50-50, NGTL places a 50 percent weighting on distance-diameter effects and a 50 percent weighting on network displacement effects. This methodology reasonably reflects the manner in which transmission costs are incurred on the Alberta System.

For intra-Alberta transportation, the Existing Methodology for conducting a cost-of-service study places a large weight on distance-diameter to the export points as a determinant of costs. This would not necessarily provide a good reflection of the relative costs of different intra-Alberta transportation hauls if NGTL did not also offer the FT-P service, which uses a highly de-averaged approach for establishing rates for specific transportation hauls based on the known distance expressed in each individual contract. For those customers who opt to use the FT-R/FT-A service combination, it is reasonable to split the intra-Alberta transmission costs so that all of these costs are collected in the FT-R component. This split provides a reasonable allocation of transmission costs to the full-haul intra-Alberta transportation rate, and it is synchronized with the FT-R/FT-D full-haul export rate in a way that reasonably assigns costs while also allowing the intra-Alberta shippers to participate in the NIT market with the export shippers.

Q65. Are there other factors that are important for your evaluation of the Existing Methodology?

A. Yes. Because it resulted from a settlement, NGTL's Existing Methodology for conducting a cost-of-service study has been shown to be at least reasonably satisfactory to (nearly) all of NGTL's customers. It therefore should be viewed as reasonably satisfying Bonbright's principle (**6)**, fairness in apportioning costs among the different consumers. By definition, the existing method also best satisfies Bonbright's principle (**5)**, stability with a minimum of unexpected changes seriously adverse to existing customers. It also has been shown in practice to satisfy Bonbright's principles (**1)** and **(2)**, understandability, public acceptability, feasibility of application, and ease of interpretation, as well as Bonbright's principle (**3)**, effectiveness in yielding revenue requirements, and Bonbright's principle (**4)**, revenue stability from year to year. Bonbright's principle **(7)**, avoidance of undue discrimination, is satisfied by the way in which partial transmission cost determinants such as distance of flow and pipe diameter are blended with factors related to unmeasurable network economies and untethered contractual flows to provide a reasonable reflection of cost responsibilities. Finally, Bonbright's principle **(8)** is reasonably satisfied by the fact that (i) most fixed transmission costs are recovered through a demand charge, (ii) a reasonable level of costs have been allocated to intra-Alberta transportation and recovered either through the FT-P rate or the FT-R component of the rate, and (iii) the long-run price signals provided by the FT-A rate are augmented by NGTL's accountability provisions and the Board's authority to regulate new construction.

1.5 Evaluation of NGTL's Alternative Cost-of-Service Study Methodologies

1.5.1. <u>Alternative 1</u>: DOH Split for Intra- v. Export and FT-R v. FT-D

Q66. What are the characteristics of Alternative 1?

A. Alternative 1 is similar to NGTL's existing toll design approach, except that the allocation of transmission costs between export and intra-Alberta markets is changed. Under NGTL's existing toll structure the average export transportation movement (FT-R/FT-D) bears twice the amount of transmission costs that are allocated to the average intra-Alberta transportation movement (FT-R/FT-A). Although the 2-to-1 relationship in the existing toll design is based on an approximation of the average distances of haul for intra-Alberta and ex-Alberta transportation, at a lower level of rounding the long-term average relationship has been 2.2 to 1. Alternative 1 adopts the actual long-term average DOH relationship by reducing the portion of transmission costs in the FT-R rate and increasing the portion of transmission costs in the FT-D rate. The net result is a reduction of approximately 1.14¢ per Mcf/d in the total FT-R/FT-A rate for intra-Alberta transportation and an increase of approximately 0.28¢ per Mcf/d in the total FT-R/FT-D rate for export transportation.

Q67. What is your evaluation of Alternative 1?

A. The advantage to this alternative is that it utilizes a more precisely measured relationship between average intra-Alberta distances and export distances and, therefore, is the direct result of a measured allocation factor. It should be noted that this approach upsets the tradition of splitting the transmission costs for export evenly between the average receipt component (FT-R) and the delivery component (FT-D) of the total export transportation charge. Moreover, because it is based on calculations of average physical flow distances, it is difficult to say that this allocation approach is a more accurate method for determining the costs incurred to provide FT-R/FT-A service combinations where *contract* flow distances may be very different from *physical* flow distances.

1.5.2. <u>Alternative 2</u>: DOH Split for Intra- v. Export; Directly Assign Facilities to Intra-Alberta

Q68. What are the characteristics of Alternative 2?

A. Alternative 2 is similar to Alternative 1 in that both alternatives allocate transmission costs between export and intra-Alberta markets using the actual long-term average DOH relationship. Alternative 2 also includes a direct assignment of a 50 percent share of certain transmission costs to the intra-Alberta transportation rates. The transmission costs that are directly assigned to intra-Alberta transportation service are based on the costs of those transmission facilities that are associated solely with receipt and delivery of intra-Alberta transportation volumes. These directly-assigned costs are split 50-50 between the FT-R receipt component and the FT-A delivery component of the intra-Alberta rate. Because this method maintains the average allocation of transmission costs to intra-Alberta transportation service at 45.5 percent of the transmission costs allocated to the export transportation service, direct assignment of certain transmission costs to the FT-R and FT-A rate components causes only a slight increase of 0.02¢ in the total intra-Alberta rate compared with Alternative 1. However, as a result of the change in the FT-R/FT-A transmission cost split this change also causes a change in the split of transmission costs between the FT-R and FT-D components of the average export transportation rate. Thus, both the FT-A and FT-D rate components increase by approximately 0.5¢ per Mcf/d in comparison with Alternative 1, while the average FT-R rate component declines by approximately 0.4¢.

The advantage of Alternative 2 might be that it directly assigns to intra-Alberta service the costs of facilities that are not associated directly with export, storage or extraction services. However, to the extent that directly assigning costs of transmission facilities that are solely associated with intra-Alberta service is adopted as an objective, there may be other transmission facilities that could arguably be directly assigned to export, storage or extraction services that have not been separately accounted for in this Alternative 2.

1.5.3. <u>Alternative 3</u>: DOH Split for Intra- v. Export; Directly Assign Facilities & TBO to Intra-Alberta

Q69. What are the characteristics of Alternative 3?

A. This alternative is similar to Alternative 2 in that it uses the same allocation of transmission costs between export and intra-Alberta transportation services, and both alternatives also directly assign to the FT-A component one-half of the costs of NGTL transmission facilities that are not associated with export, storage or extraction services. Alternative 3 is different because it also directly assigns to intra-Alberta transportation the costs of intra-Alberta TBO arrangements with Ventures, Kearl Lake and ATCO. These TBO costs are split between the FT-R and FT-A components of the intra-Alberta transportation rate with one-half of the costs going to each component. Alternative 3 results in an FT-D rate that is approximately 3¢ per Mcf/d greater than the FT-D rate calculated using the Existing Methodology. This ensures that the transmission cost component of the total intra-Alberta transportation rate remains 45.5 percent of the transmission costs included in the export rate. Alternative 3 goes further in the direction of directly assigning to intra-Alberta services costs of facilities that are not used in common to provide other services. However, it may not be an improvement over the preceding alternatives unless all facilities that can be directly assigned to other services are also identified and assigned accordingly.

1.5.4. Alternative 4: Volume*Distance for FT-R, FT-D and FT-A

Q70. What are the characteristics of Alternative 4?

A. Alternative 4 allocates the revenue requirement to each primary service based on that service's share of the total volume*distance units. The primary services are defined as FT-R, FT-D, and FT-A in this alternative. The use of volume and distance can be a strong indicator of the relative costs of transportation associated with particular services. However, the two services that are to receive an allocation of costs are intra-Alberta transportation (FT-R/FT-A) and export transportation (FT-R/FT-D). Nevertheless, Alternative 4 allocates costs to FT-R, FT-D, and FT-A as if they are separate services.

As an approach for allocating transmission costs between intra-Alberta and ex-Alberta transportation services, Alternative 4 assumes that each delivery, both intra-Alberta and export, is provided by all of the upstream receipt points based on actual system flows. Alternative 4 could be seen as being more accurate in terms of the origination of physical flows. However, on the Alberta System many of the commercial deliveries are made through displacement transactions so that the contract paths do not necessarily correspond to the physical paths that the gas flows. Thus, neither assumption concerning the origination points of gas is superior to the other when the assumption is used to design contract rates.

1.5.5. Alternative 5: Vol.*Distance for FT-R, FT-D and FT-P (No FT-A)

Q71. What are the characteristics of Alternative 5?

A. Alternative 5 allocates the revenue requirement to each primary service based on that service's share of the total volume*distance units. The primary services are FT-R, FT-D, and FT-P. This alternative is very similar to Alternative (4) except that it includes FT-P as a primary service and eliminates FT-A service, thereby requiring all intra-Alberta volumes to convert to FT-P service.

1.5.6. Alternative 6: Vol.*Dist. for FT-R, FT-D, FT-A, FT-P, FT-X, and IT-S

Q72. What are the characteristics of Alternative 6?

A. Alternative 6 allocates the revenue requirement to each primary service based on that service's share of the total volume*distance units. The primary services for this alternative are defined as FT-R, FT-D, FT-A, FT-P, FT-X, and IT-S. This approach also is similar to Alternative 4, but it allocates costs to the storage and extraction services, as well as to the intra-Alberta point-to-point service. The same advantage of perceived accuracy could be ascribed to both Alternatives 4 and 6. In addition, an allocation of costs to storage and extraction services may be reasonable in order to reflect the fact that NGTL incurs some costs to provide these services.

1.6 Summary of Evaluations

Q73. Which of the cost allocation methods is best from the standpoint of practical attributes of implementation and interpretation?

A. All of these alternatives satisfy Bonbright's principles (1) and (2) in terms of NGTL's ability to implement the alternatives, however, the existing method is the only one that has received broad acceptance by NGTL's customers.

Q74. Which of the methods is best from the perspective of producing an "accurate" allocation of costs?

A. All of the allocation approaches attempt in various ways to identify the factors that affect the relative costs of providing each service, and incorporate those factors in the allocation of costs. None of these alternatives is clearly the most accurate, but alternative 6 is the most detailed in terms of allocating costs to all services.

Alternatives 2 and 3 directly assign identifiable intra-Alberta transmission costs to intra-Alberta services, but this is only more accurate if there are no transmission costs that could be identified and directly assigned to other services, such as export transportation or storage. If such directly-assignable costs exist for other services, then an unreasonably skewed cost allocation would result from directly assigning some costs to intra-Alberta transportation and allocating directly-assignable costs of other services to all services, including intra-Alberta transportation. Moreover, directly assigning transmission costs may not make sense as a long-term practice on the Alberta System, because, in many instances, a segment that is a transmission stub at one point in time may become a general transmission facility as new supplies and facilities are connected to the system.

Alternatives 2 and 3 also allocate transmission costs between intra-Alberta and export transportation services based on the actual long-term average distance of haul ("DOH") calculation. To the extent that distance of physical flows is a good reflection of the relative costs of providing contractual flows to each service, this DOH approach is more accurate than the rough approximation of a 2-1 distance relationship that is used in the existing allocation method. However, it is not entirely clear how much weight to give to the distance of physical flows when the contractual flows are as flexible as they are for NGTL's services that utilize NIT.

Alternatives 4, 5 and 6 all allocate transmission costs to various services based on the volumes associated with each service and the average distance that each receipt and/or delivery point is from every downstream or upstream delivery or receipt point. In effect, these alternatives treat every service component as if it is a stand-alone service, even though the FT-R/FT-D and FT-R/FT-A service combinations are actually transportation services that each require two components, receipt and delivery, to provide the service. This general approach gives the appearance of greater accuracy because it produces objective factors for allocating transmission costs to each service and service component, and the volume*distance allocation approach roughly reflects factors that can cause transmission costs to vary.

In this context, Alternative 5 provides by far the most “accurate” of the three volume*distance allocation factor approaches for allocating costs to intra-Alberta services as it eliminates the FT-R/FT-A service option for intra-Alberta service and moves all intra-Alberta customers to FT-P service. By requiring intra-Alberta shippers to specify a certain limited combination of receipt and delivery points, allocation factors based on the volume*distance of physical flows will be a reasonably accurate reflection of the relative costs of facilities required to provide the contractual flows of intra-Alberta shipments. One consideration with Alternative 5 is that it sacrifices the ability of intra-Alberta customers to choose to use NIT so that the cost analysis will be more accurate.

Similarly, Alternative 6 is more “accurate” than either 4 or 5 in the sense that it allocates costs to all services, but there is concern that this alternative may not provide a reasonable allocation of costs to extraction services to the extent that transportation for extraction services is actually a joint cost. As discussed earlier in this testimony, the proper determination of relative responsibility for joint costs is determined based on the relative demand and demand elasticity for each service.

Q75. Which alternatives are best in terms of effectiveness in recovering the total revenue requirement?

A. With some qualifications or adjustments, all of the approaches should have a high probability of allowing recovery of the total revenue requirements. The total FT-R/FT-D rate is in a relatively narrow range within 0.47¢ of the Existing Methodology for all of the alternatives except Alternative 6, which produces a reduction of approximately 1.7¢ from the rate produced by the existing method.

However, one area of concern is related to the level of the FT-D rate in Alternative 3. This alternative would result in a significant increase in the FT-D rate and effectively reduce the influence of the distance and diameter factors that are used in developing the FT-R rates. As a result, the total FT-R/FT-D transportation rate may become too high at certain points and induce competitive bypasses if the FT-D rate experiences a significant increase. Because the influence of distance and diameter in the FT-R rates is already muted by the ceilings and floors that NGTL uses to limit the range of FT-R rates, an increase in the band between the ceilings and floors used to calculate the FT-R rate may be required in order to restore the influence of distance and diameter that is reduced by raising the FT-D rate. Alternatively, the large increase in the FT-D rate may cause a need to offer additional LRS rates in the future.

In addition, as discussed below, NGTL has concerns that the FT-X rate may be too high in Alternative 6. Thus, with some modifications or adjustments, all of the alternatives could satisfy Bonbright's principle (4), effectiveness in yielding total revenue requirements.

Q76. Which cost allocation methods are likely to provide the greatest stability in rates and a minimum of unexpected changes that are adverse to existing customers?

A. The Existing Methodology for conducting a cost-of-service study is likely to provide the greatest stability in both the near term and possibly further into the future and, thus, has the greatest merit with respect to Bonbright's principle (5). In the near term, the existing method produces no change in the rates that would otherwise be charged. Further into the future, the use of a fixed 2-1 factor for allocating transmission costs between intra- and ex-Alberta transportation should provide less variation in rates than either the actual long-term average DOH or the volume*distance approaches since each of these approaches can cause swings in rates if the pattern of physical gas flows changes from year to year. Much of the instability of the Alternative DOH approaches, Alternatives 1, 2 and 3, is mitigated by using a 16-year average DOH in the calculation. Consequently, the stability advantage of the Existing Methodology over the Alternative DOH measures is relatively small. The volume*distance approaches are likely to be more unstable for the delivery rates than the other approaches, but the degree to which they would be more unstable has not yet been explored.

Q77. Which alternatives are best in terms of fairness in allocating costs to all services and avoidance of undue discrimination?

A. Both attributes, fairness and avoidance of undue discrimination, can be achieved from an economic perspective when costs are allocated on a basis that reasonably reflects costs. On the Alberta System it is impossible to precisely or accurately identify the costs of providing each service or rate component because a large portion of the costs are incurred on a common, joint or inseparable basis to provide several services and serve multiple customers simultaneously.

The existing method and each of the first five alternatives have the weakness that no costs are allocated to FT-X or IT-S service. At least some allocation of costs to these services would be an improvement in terms of Bonbright's principles (6), (7) and (8), which involve fairness, avoidance of undue discrimination, and promoting efficient use of services. Thus, some version of Alternative 6 can be superior to the other methods with respect to these principles.

However, the level of costs that reasonably should be allocated to the FT-X service should be relatively low because: (i) NGTL does not incur metering costs at most extraction plants because the plants provide the metering service, (ii) extraction occurs essentially as a by-product of transportation on the system, (iii) FT-X customers purchase and pay for the transportation of replacement volumes, and (iv) the demand elasticity for this service could become high if the FT-X rate exceeds the value of the service. Because transmission costs associated with FT-X service are largely joint costs incurred to provide FT-X and other transportation services, the FT-X charge calculated for Alternative 6 is not necessarily an accurate reflection of the marginal transmission costs required to provide the service. Moreover, the FT-X customers purchase make-up gas that effectively has paid two FT-R charges for the volumes that the extraction customers require. The energy equivalent of the gas extracted at the extraction plants is provided back to the system via purchases of make-up gas by the extraction customers. As the energy content of the gas extracted is approximately twice the energy content of receipt gas, approximately 2 units of make-up gas are required for every unit of gas extracted. Thus, an argument could be made that costs allocated to FT-X service in Alternative 6 should be no less than the costs that can be directly attributably to the service, but the level of metering and transmission costs allocated to this service should be quite low in order to reasonably satisfy the principles of a sound rate structure. Moreover, because two FT-R rates are effectively paid for gas associated with FT-X service, it could be argued that no additional charge should be levied to collect the small directly-attributable costs associated with FT-X service.

Q78. Does the method of collecting the FT-A charge affect your evaluation of the ability of NGTL's existing cost allocation and rate design to satisfy the principles of a reasonable rate structure?

A. Yes. Although the FT-A rate collects fixed costs on a commodity basis, Bonbright's principle (4), revenue stability, is satisfied reasonably with NGTL's existing cost allocation and rate design method, so long as the FT-A rate recovers a relatively small portion of the total costs and the MAV accountability provision is maintained. With a relatively small portion of intra-Alberta costs recovered in the FT-A volumetric component of the total transportation rate, year-to-year cost recovery should not vary significantly as a result of variations in use by the intra-Alberta market. However, to the extent that the FT-A rate is increased significantly to collect transmission costs, the conversion of the FT-A rate to a demand-based rate should be considered in order to satisfy Bonbright's principle (4), revenue stability, and Bonbright's principle (8), promotion of all justified types and amounts of use. A high volumetric rate for recovering fixed costs would needlessly discourage efficient consumption and usage of facilities at the margin.

In addition, under the existing toll design methodology which collects fixed costs from FT-A customers on a commodity basis, low load factor FT-A customers could pay significantly less than high load factor FT-A customers for the same fixed transmission cost components and possibly fail to satisfy Bonbright's principle (7), avoidance of undue discrimination. Consequently, if fixed transmission costs are added to the FT-A rate component, a fixed charge for these costs should be implemented through either the FCS charge or conversion of FT-A to a demand charge. Alternatives 3 and 4 produce the largest increases in the FT-A rate. Consequently, consideration should be given to converting the FT-A charge from a commodity charge to a demand charge at this time if either of these alternatives is adopted.

Q79. Do the existing and alternative cost of service methodologies prepared by NGTL provide reasonable allocations of costs?

A. Yes. Like most pipelines, NGTL's costs of serving each of its different Alberta System customers are determined based on distances, economies of scale (e.g., pipeline diameter), economies of utilization (e.g., load factor), economies of scope (e.g., flexibility), existence of joint costs, common costs, and inseparable costs. All of these concepts play a role in determining the amount of costs that may be causally attributed to any one particular service. In preparing the alternatives contained in its fully-allocated cost of service studies, NGTL has utilized various reasonable methods of determining average, or fully-allocated costs so as to assign all costs to the identifiable services that it provides.

However, although a large portion of NGTL's costs are not necessarily *caused* by any single customer, or group of customers, none of these studies calculates the marginal costs that are incurred to provide service to each customer or group of customers. Cost causation is measured by *marginal* costs, but a fully-allocated cost study attempts to select a reasonable level of averaging and then calculate the *average* costs of services within a group.

Q80. Would you please summarize your conclusions concerning NGTL's fully-allocated cost of service studies?

A. My conclusions are:

(1) All of the methodologies prepared by NGTL are fully-allocated cost of service studies;

(2) All of the alternatives prepared by NGTL provide reasonable allocations of costs;

(3) The alternative to implement is determined by a weighing of the importance and significance of various characteristics and principles, such as stability, the distributional impacts on customers, and competitive constraints.

(4) The Existing Methodology for conducting a cost-of-service study continues to be appropriate at this time.

1.7 Intra-Alberta Delivery Service Accountability

Q81. How does NGTL ensure accountability for new intra-Alberta transportation facilities?

A. Like many transportation companies, NGTL recovers costs such as those of intra-Alberta transportation facilities primarily through receipt charges and FT-P charges levied on the parties who initiate the transportation. In addition, NGTL will not construct new facilities unless it is reasonably assured that demand for such facilities is sufficient to economically justify the costs of providing the facilities. The determination as to whether there is sufficient demand to justify construction of particular pipeline facilities can be based in part on a somewhat subjective judgment that there are likely to be additional customers and/or new loads developing near that location in the future. However, NGTL also employs specific charges and specific, measurable criteria to ensure that new facilities are economically justified. NGTL's FCS charge, its EAV and MAV requirements are described in Section 2.4.2 of its evidence. NGTL's MAV requirement ensures collection of all metering costs from customers at the metering point during the life of the facilities. In addition, the EAV requires delivery of at least 109.5 Bcf over three to five years after a new delivery point is connected; thereby ensuring that a substantial amount of FT-R revenues will be generated to pay transmission costs associated with new delivery points. These large volumes also ensure that new facilities have significant economies of scale and low costs per unit.

All of these charges and provisions act to ensure that NGTL does not construct new transportation facilities for which there is no demand, and that customers ensure a level of usage that justifies the cost of service for the new facilities. The FCS charge in particular is a "direct" price signal that provides a level of customer accountability for new facilities.

Q82. In some instances can there be other assurances that new facilities are economically justified?

A. Yes, but other assurances are unnecessary if new facilities meet NGTL's requirements for an EAV, an MAV, and possibly an FCS charge. For example, as described in Section 2.4 of NGTL's evidence, a large portion of the volumes transported to Simmons utilize FT-P service that commits the customers to paying for gas transportation between a limited number of receipt points and the Fort McMurray area. This FT-P service is another example of the type of "direct" price signal that is provided in the existing intra-Alberta rate structure.

Q83. What are the mechanisms for discouraging construction of uneconomic facilities?

A. In addition to the Board's ability to review new construction proposals, NGTL requires shippers on new facilities to sign contracts that include an FCS charge that is similar to a minimum bill commitment. The FCS charge includes an MAV component that requires the customer to ship at least a minimum volume of gas on the new facilities for the life of the facilities. A second component of the FCS charge is an extension annual volume ("EAV") which requires the shipper to ship at least 36.5 Bcf (an average of 100 MMcf per day) each year during a term of three years, or 109.5 Bcf over a maximum term of five years with volumes of 36.5 Bcf or more during at least one of the five years, in order to ensure that there is a substantial level of demand for the new facilities. If the shipper fails to meet these minimum volume commitments, a supplemental charge is levied under the FCS provision so that the minimum level of revenues required under the shipper's commitments is achieved. The FCS charge and its associated commitments, which are described in Section 2.4 of the Application, provide a guarantee that the new facilities will generate at least a certain amount of total transportation revenues from (i) delivery revenues through the volume and contract term commitments, and (ii) receipt revenues through the throughput commitment.

Q84. What are the concerns with intra-Alberta Delivery Service Accountability?

A. In the past there has been a concern that the intra-Alberta Delivery rate is too low to ensure that new delivery facilities are efficient. However, the evaluation of accountability for new facilities should be based on a combination of rate level, contract term, and throughput commitments.

Q85. Has NGTL evaluated the cost of service associated with intra-Alberta delivery facilities?

A. Yes, section 2.4 of NGTL's 2005 GRA Phase 2 Application shows the costs associated with intra-Alberta delivery meters, and those pipeline segments that are solely used to make physical deliveries to intra-Alberta consumption markets and not export or storage markets. This analysis also includes costs associated with the Simmons acquisition. The direct cost of service associated with these intra-Alberta delivery facilities is $10.41 million per year. When allocated overheads are added to this total, the total cost of service for intra-Alberta delivery facilities is $19.56 million.

Q86. How does the cost of service for intra-Alberta delivery facilities compare with the projected revenues that are expected to be collected from customers that are using these facilities?

A. The direct revenues from the FT-A, FT-P and FCS charges to be levied for use of these facilities are projected to be $32.35 million; an amount that is 65 percent greater than the $19.56 million cost of service, including allocated overheads, that is associated with the intra-Alberta delivery facilities. This is a very substantial margin above the cost of service of directly-attributable facilities. Therefore, there is no deficiency in the total direct revenues collected for intra-Alberta deliveries.

NGTL also projects that it will indirectly collect an additional $58 million in receipt revenue through the FT-R charges collected to serve the intra-Alberta markets.

Q87. Is it appropriate to consider Receipt revenues in assessing the economic value of new facilities?

A. Yes. In a competitive market, evaluation of new delivery facilities should consider the total Receipt revenues that can be retained as part of the total transportation revenues associated with a new project.

Q88. As a general matter why is the calculation of marginal revenue different for a pipeline that (i) splits the cost of transportation service between separate receipt and delivery contracts and (ii) operates in a competitive market?

A. A pipeline that splits the cost of transportation between separate receipt and delivery contracts might be able to ignore the impact on receipt revenue that occurs when it adds or loses a delivery contract customer if the pipeline faces no competition and can confidently predict that its receipt revenue is entirely unaffected by the decision to deliver gas to a particular market.

However, a pipeline that faces competition cannot assume that its existing receipt revenues are assured in the future. Nor does it have any guarantee that new receipt points and new receipt volumes will attach to its system as existing production is exhausted and must be replaced. A competitive pipeline can only retain and attract customers at receipt points to the extent that it transports gas to markets where its customers want to sell their gas, and only to the extent that it offers a better overall value than its competitors. When a large new market develops that is sufficiently attractive to its existing customers, a competitive pipeline cannot ignore that development. Instead it must seek to serve the changing needs of its customers or some other pipeline will provide the services that those customers desire, and *current* receipt customers will become *former* receipt customers.

A proper economic analysis in a competitive market therefore will recognize that many of the current receipt revenues may not exist in the future if the pipeline fails to provide transportation access to large new nearby gas consumption markets. This realization frames the choice for the future as being between (a) retention and attraction of receipt revenues by providing facilities to deliver gas to new downstream markets, or (b) reduced receipt revenues at some receipt points as competitors construct dual-connections and/or connections to new receipt points and capture both the delivery and, eventually, the receipt ends of the market. Thus, proper calculation of marginal receipt revenues in a competitive market generally would be as follows:

Marginal Receipt Revenue — With Competition	
	Future Expected Receipt Revenue
(a) Build new delivery facilities	$100
(b) Decline to build delivery facilities	**$0** .
Marginal Receipt Revenue ((a) – (b))	**$100**

A forward-looking comparison of option (a) to option (b) clearly reveals that retained receipt revenues generally will be positive marginal revenues for purposes of analyzing the merits of new delivery facilities in a competitive market. Thus, constructing new facilities may or may not increase receipt revenues in the future, but receipt revenues generally must be treated as "marginal" revenue when a ***competitive*** pipeline evaluates the economic consequences of serving the evolving needs of the market.

Q89. How does competition impact the analysis of revenues associated with projects undertaken by NGTL to directly attach its system to intra-Alberta consumption markets?

A. As shown in section 2.3 of NGTL's evidence, NGTL has lost a portion of the intra-Alberta market that it formerly served by providing upstream transportation into the ATCO Pipelines systems. For NGTL this has meant a loss in receipt revenues that can be collected by NGTL for transporting gas to intra-Alberta markets.

Q90. Does competition constrain NGTL's ability to cross-subsidize uneconomic mainline extensions?

A. Yes. The past decade has demonstrated that NGTL is constrained to a very large degree by competition. Customers and other transportation providers have demonstrated the ability and willingness to construct by-pass pipelines wherever NGTL's rates exceed the competitive cost of providing service. This competition prevents NGTL from charging excessive rates to some customers and using the excess revenues to subsidize other services.

Q91. Are there other features that prevent cross-subsidization of uneconomic mainline extensions?

A. In the 1990s there was some concern that tolls in NGTL's rolled-in, postage stamp rate structure were not fully-recovering the costs of constructing and operating high-cost, small-diameter facilities that would only be used by a very small number of customers. This concern was primarily expressed by customers that required use of low-cost facilities since these customers felt that they were subsidizing the use of high-cost receipt facilities that were longer and/or of smaller-diameter. NGTL addressed these concerns by adopting a distance-diameter toll design that more closely reflects the costs of individual facilities. But NGTL also went an extra step further in agreeing not to roll in "laterals," which often have a relatively high cost per unit. Instead, these types of facilities are to be constructed in a competitive market that does not include NGTL. This step also largely satisfied those parties that wished to compete with NGTL, but felt that NGTL's regulated rate structure provided cross-subsidies to "laterals" that would prevent fair competition. NGTL's ability to cross-subsidize high-cost, uneconomical facilities is greatly constrained by: (i) its definition of laterals, (ii) its MAV and EAV tests for facilities, (iii) its FCS charge, (iv) its distance-diameter toll design, and (v) pervasive actual and potential competition that it faces throughout its regulated system – including competition with companies that are not under the jurisdiction of the EUB.

Q92. Is NGTL proposing any changes to the accountability provisions currently in its tariff?

A. No. NGTL is not proposing any changes to the accountability provisions in its tariff at this time, but in its testimony NGTL outlines several changes that could be made if the Board feels that changes to the accountability provisions are required.

Q93. Could changes to the intra-Alberta EAV provision be made to better align accountability with the costs of pipeline facilities required to attach new intra-Alberta delivery points?

A. Currently the Extension Annual Volume commitment requires a standard level of throughput, regardless of the cost of the extension. In order to more closely align the EAV commitment with the costs of specific projects, the EAV component of the FCS charge could be revised so that the throughput commitment is designed to ensure that the cumulative present value of estimated transportation revenues (“CPVR”) equals a specific portion of the cumulative present value cost of service (“CPVCOS”) of the extension facilities. The CPVR could be based on the amount and timing of the volume commitment for the facilities, multiplied by the transmission component of the rates that is embedded in either: (i) the average FT-R/FT-A service combination rate, or (ii) the FT-P rates for FT-P contracts at the new delivery point(s). The initial CPVR does not need to equal the CPVCOS of the extension facilities if the company is reasonably confident that the facilities will be used to transport additional volumes during and after the initial firm contracts, but an initial contractual commitment from some combination of customers that ensures recovery of, for example, 50 percent of the CPVCOS would be reasonable in many instances. In addition, there should be a high level of flexibility for NGTL and the customer(s) to agree on a combination of timing and volume level that would achieve the required CPVR. This possible change in accountability would allow inexpensive extension facilities to make an EAV commitment that is smaller than the EAV commitment required for more expensive EAV facilities and, in some instances, might somewhat reduce the risks borne by the Alberta System when delivery extensions are constructed.

1.8 Competitive Considerations for the Alberta System's Rates

Q94. Is competition a consideration in evaluating various cost allocation methodologies for the Alberta System?

A. Yes. In recent years, at the receipt end Alberta has been an open, competitive market with a considerable amount of new pipeline construction to provide dual-connections to gas receipt points. The Alberta System has lost portions of its export transportation business to competing direct-export pipelines such as Alliance and Suffield (AltaGas), and to indirect exports accomplished through ATCO Pipelines deliveries to TransGas[12] and Alliance.

In addition, although the Alberta System has historically been an important upstream transporter of gas for ATCO Pipelines and ATCO Gas, there has been a large increase in the amount of competition between the Alberta System and ATCO Pipelines in recent years. The results of that increase in competition are discussed in section 2.3 of NGTL's 2005 GRA Phase 2 evidence. Some of that competition is to serve new, unserved markets or incremental loads, but much of it involves ATCO Pipelines building upstream facilities that duplicate receipt point connections and eliminate the Alberta System from the transportation chain. The Alberta System's loss of load to ATCO Pipelines is shown graphically on Figures 2.3-1 to 2.3-3 in section 2.3 of NGTL's evidence.

Q95. Can the Alberta System maintain a reasonable competitive position with rates based on its existing cost allocation methodology?

A. Yes. Although it has experienced significant losses of volumes and revenues in both the export and the intra-Alberta transportation markets, rates based on the

[12] TransGas operates at Alberta border export points through the Many Islands Pipe Line.

Existing Methodology for conducting a cost-of-service study appears to give the Alberta System a reasonable opportunity to compete for business because it reasonably reflects the costs of transportation on the Alberta System. In addition, although pipeline rates are an important consideration, there are several other dimensions that play an important role in the competition between pipelines in Alberta. For example, different pipelines compete with each other within Alberta by providing access to different markets, different flexibility of services, and different potential to connect new supplies of gas in the future.

In the following sub-sections I describe some of the competitive considerations with respect to the Alberta System's rates as it competes to serve (i) intra-Alberta markets and (ii) export markets.

1.8.1. Competition Between ATCO Pipelines and the Alberta System

Q96. What kinds of competitive transactions have been responsible for the Alberta System's loss of business to competitors in the intra-Alberta market?

A. There have been many different types of transactions whereby the Alberta System has lost business to competitors in the intra-Alberta market. However, one of the most common transactions has occurred when the Alberta System has been attached to a gas plant and delivers gas to an intra-Alberta pipeline, such as ATCO Pipelines, that in turn is attached to various intra-Alberta consumption markets. In these situations, the two pipelines act in a cooperative manner to transport intra-Alberta gas volumes; the Alberta System is attached to gas production on the receipt side and delivers to a downstream pipeline that is attached to consumption markets on the delivery side of its system. The cooperation ends, and the competition begins, when either:

(i) the pipeline in the chain that is primarily attached to consumption markets (e.g., ATCO Pipelines) constructs a backward extension of its system to create a dual-connection to a production plant, and thereby bypass the Alberta System's upstream facilities and avoid the total FT-R/FT-A transportation charges; and/or

(ii) the pipeline that is primarily attached to gas production markets (e.g., the Alberta System) attempts to construct a forward extension of its system to create a dual-connection to an end-user or consumption market, and thereby bypass the downstream pipeline so that the Alberta System can replace or retain FT-R/FT-A revenues.

In either competitive situation, it is revenue from a total transportation charge, FT-R plus FT-A, that is at risk for the Alberta System's business.

Q97. Has the Alberta System been able to compete successfully with ATCO Pipelines to serve intra-Alberta markets?

A. Both pipelines have had some successes in attempting to attach and serve entirely new intra-Alberta consumption markets. However, in recent years the Alberta System has lost intra-Alberta business in situations where the Alberta System was part of a transportation chain that served intra-Alberta markets by delivering gas to ATCO Pipelines which, in turn, is directly connected to consumption markets.

As shown in section 2.3 and Figures 2.3-1 to 2.3-3 of NGTL's evidence, ATCO Pipelines has constructed facilities to provide dual receipt-point connections to gas production facilities that are also connected to the Alberta System. As a consequence, the Alberta System has effectively been by-passed and eliminated from the receipt end of the transportation chain in situations where

ATCO Pipelines is the pipeline in the chain that is directly connected to intra-Alberta delivery markets. Thus far, the Alberta System has been largely unsuccessful in its attempts to compete to regain receipt volumes and revenues lost to ATCO Pipelines by constructing its own pipeline segments to connect directly to intra-Alberta delivery markets that are also connected to ATCO Pipelines. However, the Alberta System may be able to mitigate further losses of volumes and revenues at receipt points by using TBO arrangements with ATCO Pipelines so that the Alberta System can obtain its own direct access to intra-Alberta consumption markets. Nevertheless, as shown on tables 2.3-2 and 2.3-3 of NGTL's Application, the Alberta System has lost both receipt and delivery volumes when ATCO Pipelines has constructed dual connections at receipt points.

Q98. How do the Alberta System's rates that are calculated according to the Existing Methodology compare with those of ATCO Pipelines?

A. As shown on Table 1.8 in Appendix 2D-3, the stations that have dual connections to both ATCO Pipelines and the Alberta System all have separate receipt and delivery rates associated with their intra-Alberta transportation service options. For most of the stations in the ATCO Pipelines-North area, ATCO Pipelines has the lowest *total* transportation rate. However, it also can be seen that the total transportation rates of the two companies in the north generally consist of (i) ATCO Pipelines' receipt rates that are lower than the Alberta System's receipt rates, and (ii) ATCO Pipelines' delivery rates that are higher than the Alberta System's delivery rates. ATCO Pipelines' lower receipt rates in the North are in part a result of the Alberta System's toll design which sets individual receipt rates according to diameters and distance to the Alberta border export points.

Conversely, the Alberta System's *total* transportation rates in the ATCO Pipelines-South area tend to be lower than those of ATCO Pipelines at the dual-connected receipt points because the Alberta System's receipt rates in the south tend to be lower than its receipt rates in the north. Neither company has lower total transportation rates at all stations and, thus, there is no clear competitive advantage obvious in the rates of these two companies. In considering individual service components, ATCO Pipelines' Receipt tolls generally are lower than the Alberta System's receipt tolls, but these relationships are reversed for the delivery tolls.

Q99. What implications do these rate relationships have for evaluating the Alberta System's rates?

A. It is the total rates for transportation service that is most important for evaluating reasonable rates.

In addition, unlike the vast majority of pipelines, the Alberta System and ATCO Pipelines separate the receipt and delivery components of the total transportation rate, but they split transmission costs between receipt and delivery components very differently. From the standpoint of cost causation, there is no single correct ratio to use in splitting transmission costs among receipt and delivery services because both "services" are simply components of a single transportation service.

To the extent that the Board believes that the Alberta System's FT-A rate does not include a sufficient share of transmission costs, it is clear that the total transmission costs in the total intra-Alberta transportation rate are not particularly low relative to those of competitors. It also is clear that NGTL's attempt to design FT-R rates that apply simultaneously to both (i) export and (ii) intra-Alberta delivery markets may not accurately reflect the relative total transportation costs for intra-Alberta transportation service in different parts of the Province. Primarily for this reason, the Alberta System also offers points-to-point transportation service that encompasses the receipt and delivery components within a single transportation service.

Q100. Should the Alberta System's tolls be set with a goal of improving ATCO Pipelines' competitive position?

A. No. the Alberta System's tolls should reflect the costs of its services and whatever competitive constraints that it faces, but they should not be set with a goal of improving the competitive position of its competitors so long as the method used to set the tolls reasonably reflects costs.

1.8.2. Competition Between NGTL and Non-Jurisdictional Entities

Q101. What is the significance of competition between NGTL and non-jurisdictional pipelines for setting the Alberta System's rates?

A. the Alberta System substantially de-averaged its postage stamp toll design in 2000 to respond to the fact that its toll design encouraged numerous proposals to construct export pipelines where, because of the transportation load characteristics, a new pipeline could be constructed and operated at a cost that was lower than the Alberta System's postage stamp toll design. Although the revenue requirement and overall rate level is still based on average, embedded costs, the Alberta System's distance-diameter toll design tracks its costs of providing transportation services to specific customers more closely than did its postage stamp toll design. Nevertheless, competition from non-jurisdictional export pipelines forces NGTL to ensure that the Alberta System's full-haul export rates are competitive.

1.9 Conclusions

Q102. What are your conclusions concerning the cost allocation methodologies filed by NGTL in this proceeding?

A. At the outset of this testimony I discussed why it is impossible to accurately measure the costs causally attributable to specific services or customers on the Alberta System. Instead, there can be a wide range of reasonable rates and a fully-allocated cost of service study is a method of calculating a set of rates that represents a compromise between the various cost concepts that can be economically relevant. There are numerous fully-allocated cost of service methodologies that can be used on a pipeline such as the Alberta System, but the methodology employed should generally reflect the manner in which costs are incurred on average as well as reasonable differences in the costs of providing different services, and also consider factors such as demand elasticity and various policies and priorities. Each of the alternatives prepared by NGTL provides a reasonable allocation of embedded costs to various services because they are based on allocation factors that reasonably reflect the major determinants of costs on the Alberta System. Although each of the alternatives discussed in Section 2 of NGTL's 2005 Phase 2 GRA Application are reasonable, there are different characteristics associated with each alternative that the Board may wish to consider within the context of its policies concerning relevant costs, competition, accountability, or other considerations. However, the Existing Methodology for conducting a cost-of-service study continues to be appropriate at this time.

Q103. Does this conclude your written testimony?

A. Yes.

APPENDIX 2D-1

Curriculum Vitae
Of J. Stephen Gaske

J. STEPHEN GASKE

H. Zinder & Associates
7508 Wisconsin Avenue
Bethesda, MD 20814

CAREER SUMMARY

Consulting:

1988-Present	H. Zinder & Associates, President/Senior Vice-President/Consultant
1982-1988	Independent Consulting on Public Utility issues
1980-1981	Olson & Company, Inc., Public Utility Consultant
1977-1980	H. Zinder & Assocs., Research Assistant and Supervisor of Regulatory Research

Academic/Teaching:

1986-1988	Trinity University, Assistant Professor of Finance
1982-1986	Indiana University School of Business, Associate Instructor of Public Utilities and Transportation
1978	Northern Virginia Community College, Lecturer in Accounting

EDUCATION

Indiana University School of Business — Ph.D. • 1987
Concentrations: Major - Public Utilities; Minor - Finance; Methodology - Economics
Dissertation: **Two-Part Tariffs, Welfare, and the Cost of Capital to the Regulated Firm**

George Washington University — M.B.A. • 1977
Major Concentration: Finance and Investments

University of Virginia — B.A. • 1975

PROFESSIONAL ASSOCIATIONS

American Economic Association
American Finance Association
American Gas Association Rate Committee (1989-2001)
Financial Management Association

PROFESSIONAL EXPERIENCE

Testimony and Litigation Support

Dr. Gaske has testified or filed testimony or affidavits in approximately 60 regulatory proceedings on the following topics:

Commission	Topic
Alaska Regulatory Commission	Oil Pipeline Rate of Return/Rate Base
Alberta Energy and Utilities Board	Gas Pipeline Cost Allocation/Rate Design
U.S. Economic Regulatory Administration	Gas Distribution Rate Design
U. S. Federal Energy Regulatory Commission	Gas Pipeline Cost Allocation and Rate Design; Rate of Return and Capital Structure; Competition; Revenue Requirements; Oil Pipeline Rate of Return
Iowa UB	Electric Avoided Costs/Externalities
Maine PUC	Electric Rate Design/Demand Management
CRE de México	Gas Pipeline Rate of Return
Montana PSC	Gas Distribution/Electric Rate of Return; Electric Cost Allocation and Rate Design
Minnesota PUC	Gas Distribution Rate of Return
New York PSC	Gas Pipeline Capital Structure
North Dakota PSC	Electric/Gas Distribution Rate of Return; Natural Gas Market Pricing; Electric Cost Allocation and Rate Design
U.S. Postal Rate Commission	Postal Pricing/Rate Design
South Dakota PUC	Gas Distribution Rate of Return
Texas PUC	Electric Cost Allocation and Rate Design
Wisconsin PSC	Electric Generation Economics
Wyoming PSC	Electric/Gas Distribution Rate of Return

Dr. Gaske has testified in property tax valuation proceedings before the Wyoming Board of Equalization and the Colorado Board of Assessment Appeals. He also has provided expert litigation support on cost of capital, cost allocation, rate design, cost of service, competition, market power and other economic and finance-related issues as part of numerous rate cases, antitrust and civil proceedings in which he did not testify.

Reports and Economic/Financial Analyses

Dr. Gaske has worked on many consulting projects in the area of utility economics, rates and regulation. Some of these projects have included:

- advisor to numerous U.S. and Canadian pipelines on rate design and/or competitive economics;
- rate and financial advisor during development stage for a new pipeline designed to carry Canadian gas to U.S. New England markets;
- an analysis of the applicability of various finance theories to telephone ratemaking by the U. S. Federal Communications Commission;
- a study of the economic structure, risks and cost of capital of the satellite telecommunications industry;
- development of computerized cost of service models for calculating both traditional and levelized rates for gas and oil pipelines, and rates for electric utilities;
- author of several issues of the H. Zinder & Associates Summary of Natural Gas Pipeline Rates;
- several studies of regional natural gas market competition, market power, pricing and capacity needs;
- an evaluation of Federal Energy Regulatory Commission policies designed to promote liquidity in the natural gas commodity markets;
- numerous studies of electric rate, regulatory and market issues such as canceled plant treatment, time-differentiated rates, non-utility generation, competitive bidding, and open-access transmission;
- author of the two most recent updates of the Edison Electric Institute Glossary of Electric Utility Terms;
- several studies of pricing, contract provisions, competitive bidding programs, and transmission practices for independent electric generation; and,
- several reports and projects on incentive regulation and the application of price cap regulation to both electric and natural gas companies.

Teaching/Speaking

Dr. Gaske has spoken on utility finance and economic issues before numerous professional groups. From 1983-1986, he served as Coordinator of the Edison Electric Institute Electric Rate Fundamentals Course. In addition, Dr. Gaske has taught college courses in Public Utility Economics, Transportation, Physical Distribution, Financial Management, Investments, Corporate Finance, and Corporate Financial Theory.

TABLE 1.3-1
Summary of Cost Allocation Methodologies

Administrative and General Overheads

Functions Allocated or Assigned		Allocation Factor	Split	Used By
A&G Overheads				
Metering v. Transmission		Generally allocated to Metering or Transmission Functions Based on the Relative Net Book Values of Metering and Transmission Assets		All
Exceptions:				
- Line Pack		100% to Transmission		All
- Maintenance		Allocated using historical average ratios of 35% related to metering and 65% related to transmission		All
Method of Allocating Costs to Rates or Rate Components		A&G costs are allocated to Metering or Transmission Functions and then allocated or assigned to rates or rate components on the same basis that Metering and Transmission function costs are allocated or assigned.		All

TABLE 1.3-2
Summary of Cost Allocation Methodologies

Metering Costs

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
<u>Metering Costs</u>				
All services, excluding FT-X and IT-S		Average Rate is Calculated Using Base Period Metered Volumes from all Services, Metering Costs are then Allocated to all Services Excluding FT-X and IT-S		E, 1, 2, 3, 4, 5
All services, including FT-X and IT-S		Average Rate is Calculated Using Base Period Metered Volumes from all Services, Metering Costs are then Allocated to all Services Including FT-X and IT-S		6

Note:

E – "Existing Methodology"
– Alternative Number

TABLE 1.3-3
Summary of Cost Allocation Methodologies

Transmission Costs – Existing Methodology

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Allocation Based on Approximate DOH: Intra-Alberta Cost per Mcf = 50% of Export**		**E**
- **Export:** FT-R/FT-D		Split based on DOH	50-50	E
- **Intra-AB:** FT-R/FT-A		Split based on 50-50 constraint	100-0[1]	E
- **Intra-AB:** FT-P		Rate Derived From FT-R/FT-A		E,1,2,3, 4
- **Intra-AB:** FT-X & IT-S		No costs allocated to these services		E,1,2,3, 4,5

[1] The 100-0 split of transmission costs between FT-R and FT-A results from two constraints: (i) allocating to intra-Alberta transportation 50% for of the total transmission costs per Mcf that are allocated to Export transportation; and (ii) the 50-50 split of transmission costs between the FT-R and FT-D components of the total export transportation rate.

TABLE 1.3-4
Summary of Cost Allocation Methodologies

Transmission Costs – Alternatives 1, 2 and 3
Alternative 1

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Allocated Based on CD Distance of Haul: Intra-Alberta Cost per Mcf = 45.5% of Export**		**1, 2, 3**

Alternative 1

- **Export:** FT-R/FT-D		Split based on actual long-term average DOH	45.5-54.5	1
- **Intra-AB:** FT-R/FT-A		Split Based on DOH constraint	100-0[1]	E,1
- **Intra-AB:** FT-P		Rate Derived From FT-R/FT-A		E,1,2,3,4
- **Intra-AB:** FT-X & IT-S		No costs allocated to these services		E,1,2,3,4,5

[1] The 100-0 split of transmission costs between FT-R and FT-A results from two constraints: (i) allocating to intra-Alberta transportation 45.5% of the total transmission costs per Mcf that are allocated to Export transportation; and (ii) using a 45.5-55.5 split of transmission costs between the FT-R and FT-D components of the total export transportation rate.

TABLE 1.3-4
Summary of Cost Allocation Methodologies

Transmission Costs – Alternatives 1, 2 and 3
Alternative 2

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Allocated Based on CD Distance of Haul:** **Intra-Alberta Cost per Mcf = 45.5% of Export**		**1, 2, 3**

Alternative 2

- **Export:** FT-R/FT-D		Split based on actual long-term average DOH and Direct Assignment constraints[2]		2
- **Intra-AB:** FT-R/FT-A		Direct Assign 50% of Intra-Alberta Delivery Facilities to FT-A.[3] Remainder of Intra-Alberta Delivery Facilities assigned to FT-R		2
- **Intra-AB:** FT-P		Rate Derived From FT-R/FT-A		E,1,2,3, 4
- **Intra-AB:** FT-X & IT-S		No costs allocated to these services		E,1,2,3, 4,5

[2] The split of transmission costs between FT-R and FT-D results from two constraints: (i) allocating to intra-Alberta transportation 45.5% of the total transmission costs per Mcf that are allocated to Export transportation; and (ii) directly assigning 50% of the costs associated with intra-Alberta facilities to the FT-A component of the total intra-Alberta transportation rate.

[3] These are facilities that are not associated with export, storage or extraction and, thus, are associated with receipt and intra-Alberta delivery.

TABLE 1.3-4
Summary of Cost Allocation Methodologies

Transmission Costs – Alternatives 1, 2 and 3
Alternative 3

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Allocated Based on CD Distance of Haul: Intra-Alberta Cost per Mcf = 45.5% of Export**		**1, 2, 3**

Alternative 3

- **Export:** FT-R/FT-D		Split based on actual long-term average DOH and Direct Assignment constraints[4]		3
- **Intra-AB:** FT-R/FT-A		Direct Assign 50% of costs associated with Intra-Alberta Delivery Facilities & TBO's to FT-A.[5] Remainder of Intra-Alberta costs are assigned to FT-R.		3
- **Intra-AB:** FT-P		Rate Derived From FT-R/FT-A		E,1,2,3, 4
- **Intra-AB:** FT-X & IT-S		No costs allocated to these services		E,1,2,3, 4,5

[4] The split of transmission costs between FT-R and FT-D results from two constraints: (i) allocating to intra-Alberta transportation 45.5% of the total transmission costs per Mcf that are allocated to export transportation; and (ii) directly assigning 50% of the costs associated with intra-Alberta facilities and TBO transmission costs to the FT-A component of the total intra-Alberta transportation rate.

[5] These are facilities that are not associated with export, storage or extraction and, thus, are associated with receipt and intra-Alberta delivery.

TABLE 1.3-5
Summary of Cost Allocation Methodologies

Transmission Costs – Alternatives 4, 5 and 6
Alternative 4

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Implicitly Allocated Using Volume*Distance For Each Rate or Rate Component**		**4, 5, 6**

Alternative 4

FT-R v. FT-D v. FT-A		Allocated using Volume * Distance Index for Each Primary Rate Component As If It Is A Stand-Alone Transportation Service		4
- **Export:** FT-R/FT-D		Sum of transmission costs allocated to FT-R and FT-D using Volume * Distance		4
- **Intra-AB:** FT-R/FT-A		Sum of transmission costs allocated to FT-R and FT-A using Volume * Distance		4
- **Intra-AB:** FT-P		Rate Derived From FT-R/FT-A		E,1,2,3, 4
- **Intra-AB:** FT-X & IT-S		No costs allocated to these services		E,1,2,3, 4,5

TABLE 1.3-5
Summary of Cost Allocation Methodologies

Transmission Costs – Alternatives 4, 5 and 6
Alternative 5

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Implicitly Allocated Using Volume*Distance For Each Rate or Rate Component**		**4, 5, 6**

<u>**Alternative 5**</u>

FT-R v. FT-D v. FT-P		Volume * Distance Index for Each Primary Rate or Rate Component As If It Is A Stand-Alone Transportation Service (Eliminates FT-A)		5
- **Export:** FT-R/FT-D		Sum of FT-R plus FT-D transmission costs allocated using Volume * Distance		5
- **Intra-AB:** FT-R/FT-A		Not applicable: FT-A eliminated		5
- **Intra-AB**: FT-P		Transmission costs allocated to FT-P using Volume * Distance[1]		5, 6
- **Intra-AB:** FT-X & IT-S		No costs allocated to these services		E,1,2,3, 4, 5

[1] Alternative 5 would eliminate the FT-R/FT-A service option for intra-Alberta transportation. FT-P allocation units are calculated using volume * distance for all intra-Alberta delivery points assuming that FT-R/FT-A customers convert to FT-P service by connecting each intra-Alberta delivery point to the receipt points upstream of that delivery point based on actual system flows.

TABLE 1.3-5
Summary of Cost Allocation Methodologies

Transmission Costs – Alternatives 4, 5 and 6
Alternative 6

Allocated or Assigned to Rates/Compon.		Allocation Factor	Split	Used By
Intra-Alberta v. Export		**Implicitly Allocated Using Volume*Distance For Each Rate or Rate Component**		**4, 5, 6**

Alternative 6

FT-R v. FT-D v. FT-A v. FT-P v. FT-X v. IT-S		Volume * Distance Index for Each Primary Rate or Rate Component As If It Is A Stand-Alone Transportation Service[2]		6
- **Export:** FT-R/FT-D		Sum of FT-R plus FT-D transmission costs allocated using Volume * Distance		6
- **Intra-AB:** FT-R/FT-A		Sum of FT-R plus FT-A transmission costs allocated using Volume * Distance		6
- **Intra-AB**: FT-P		Transmission costs allocated to FT-P using Volume * Distance		5, 6
- **Intra-AB:** FT-X & IT-S		Transmission costs allocated to FT-X and IT-S using Volume * Distance		6

[2] FT-P, FT-X and IT-S allocations are based on the assumption that each delivery point attaches to the receipt points upstream of that delivery point based on actual system flows.

Table 1.8

Comparison of NGTL and ATCO Pipelines
Full Path Tolls from Dually-Connected Stations

(¢/Mcf)

			NGTL Intra-Alberta Tolls				ATCO Pipelines Tolls (FSD)				Difference	AP Tolls (FSU)		Difference
ATCO Station Name	NGTL Station #	NGTL Station Name	3-YR FT-R	Fuel	FT-A	Total Full Path	Receipt Tolls	Fuel	Delivery (FSD)	Full Path (FSD)	ATCO (FSD) Less NGTL	Delivery (FSU)	Full Path (FSU)	ATCO (FSU) Less NGTL
ATCO NORTH														
ANSELL	1064	EDSON	11.2	5.1	1.42	**17.7**	9.1	4.9	7.0	**21.0**	**3.2**	7.9	21.8	4.1
BONNIE GLEN	1796	BONNIE GLEN	14.7	5.1	1.42	**21.2**	9.1	4.9	7.0	**21.0**	**(0.2)**	7.9	21.8	0.6
LLOYD CREEK	1949	RIMBEY/WESTEROSE SUMMARY	10.0	5.1	1.42	**16.5**	9.1	4.9	7.0	**21.0**	**4.5**	7.9	21.8	5.3
MANNVILLE	1164	RANFURLY	21.5	5.1	1.42	**28.0**	9.1	4.9	7.0	**21.0**	**(7.0)**	7.9	21.8	(6.2)
MCLEOD RIVER	1572	MARLBORO	15.8	5.1	1.42	**22.3**	9.1	4.9	7.0	**21.0**	**(1.3)**	7.9	21.8	(0.5)
SOUTH CARROT CREEK	2111	LOBSTICK	10.4	5.1	1.42	**16.9**	9.1	4.9	7.0	**21.0**	**4.0**	7.9	21.8	4.9
SUNDANCE CREEK	1516	SUNDANCE CREEK	16.5	5.1	1.42	**23.0**	9.1	4.9	7.0	**21.0**	**(2.1)**	7.9	21.8	(1.2)
TRIBUTE	2022	JUDY CREEK	22.7	5.1	1.42	**29.3**	9.1	4.9	7.0	**21.0**	**(8.3)**	7.9	21.8	(7.4)
VANTAGE	2209	CYNTHIA #2	9.5	5.1	1.42	**16.0**	9.1	4.9	7.0	**21.0**	**5.0**	7.9	21.8	5.8
VIKING NORTH	1841	TORLEA EAST	16.7	5.1	1.42	**23.2**	9.1	4.9	7.0	**21.0**	**(2.3)**	7.9	21.8	(1.4)
System-Wide Average Rates			15.5	5.1	1.42	**22.0**	9.1	4.9	7.0	**21.0**	(1.0)	**7.9**	**21.8**	(0.2)
ATCO SOUTH														
GAYFORD	1747	NIGHTINGALE	7.5	5.1	1.42	**14.0**	9.8	2.7	5.2	**17.7**	**3.7**	6.4	18.9	4.9
HILLSDOWN	1739	PIPER CREEK	11.0	5.1	1.42	**17.5**	9.8	2.7	5.2	**17.7**	**0.2**	6.4	18.9	1.4
JUMPING POUND W	2036	JUMPING POUND W	7.5	5.1	1.42	**14.0**	9.8	2.7	5.2	**17.7**	**3.7**	6.4	18.9	4.9
NEVIS SOUTH	1019	NEVIS SOUTH	12.0	5.1	1.42	**18.6**	9.8	2.7	5.2	**17.7**	**(0.8)**	6.4	18.9	0.3
OLDS	1053	OLDS	9.5	5.1	1.42	**16.0**	9.8	2.7	5.2	**17.7**	**1.7**	6.4	18.9	2.9
SHARPLES	1623	GATINE	7.5	5.1	1.42	**14.0**	9.8	2.7	5.2	**17.7**	**3.7**	6.4	18.9	4.9
System-Wide Average Rates			15.5	5.1	1.42	**22.0**	9.8	2.7	5.2	**17.7**	(4.3)	**6.4**	**18.9**	(3.1)

Assumptions:

FTR Receipt Tolls based on NGTL 2005 Phase 2 Application
ATCO Tolls 2004 Final Rates (these rates carry over to 2005)
North Receipt Rate = 8.5 ¢/GJ, South Receipt Rate = 9.2 ¢/GJ
North 3 yr FSD = 6.6 ¢/GJ, South 3 yr FSD = 4.9 ¢/GJ
North FSU = 7.4 ¢/GJ, South FSU = 6.0 ¢/GJ
ATCO's tolls converted to Mcf based on a conversion of .9390 GJ = 1 Mcf (based on a heat value of 37.8 mj/m ^{3})
APN UFG & Fuel Rate – 0.836%
APS UFG & Fuel Rate – 0.460%

NGTL Fuel Rate – 0.87% (July/03 - Dec/03 average fuel rate)
Gas Price - $5.50/GJ (Mid December winter strip for AECO “C” Monthly)
Fuel costs converted to Mcf based on a conversion of .9390 GJ = 1 Mcf (based on a heat value of 37.8 mj/m ^{3})

3.0 SERVICES AND TARIFF AMENDMENTS

3.1 INTRODUCTION

Q1. What is the purpose of this evidence?

A1. The purpose of this evidence is to support NGTL's request for approval of certain modifications to export delivery services (FT-D, FT-DW, STFT and IT-D) to implement the use of energy units (GJ) rather than the existing volumetric units (10^3m^3) for existing and new contracts.

It is also to support proposed housekeeping changes to the Tariff.

3.2 ENERGY CONVERSION

Q2. Please provide an overview of the current contracting practice for service at export delivery points.

A2. Currently, all Alberta System contracts for service at export delivery points are in volumetric units while customer inventories are tracked and transactions are conducted in energy units. In order to calculate the energy equivalent of a volumetric contract for service, every month NGTL posts a heat value for each of the major export delivery points. The posted heat value is determined from historical trends, projected throughput, and anticipated changes in the overall operation.

Q3. Does NGTL have any concerns with volume contracting?

A3. Yes. NGTL's current practice of contracting in volumetric units at export delivery points results in inefficiencies due to the need for conversions between volumetric and energy units. Customer inventory accounts are maintained in energy and NOVA Inventory Transfers (NITs) are transacted in energy (GJs). Pipeline to pipeline transactions at export delivery points are conducted in energy units but NGTL export contracts and rates are volumetric.

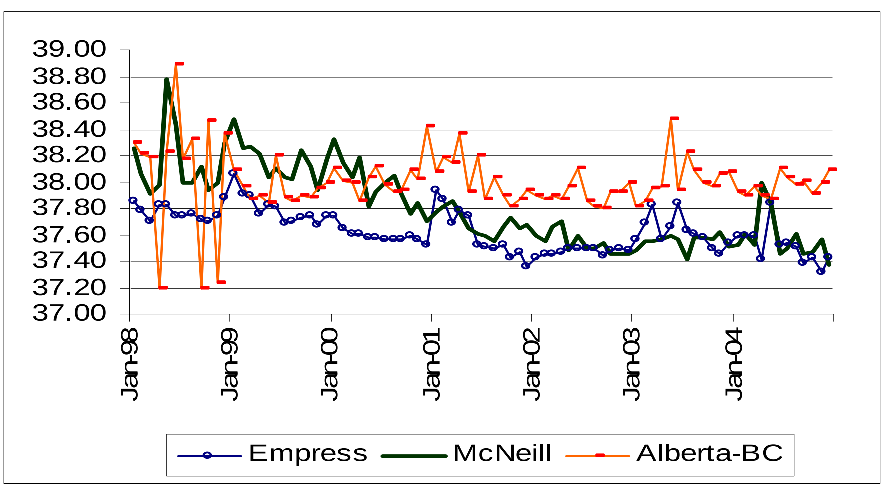
Contracting in volumetric units while transacting in energy can create mismatches of capacity. Under NGTL's present practice, when the heat value of the common stream at an export delivery point changes, the quantity of energy that a customer can deliver by contract to the downstream connected pipeline also changes, as shown in Table 3.2-1 below.

Table 3.2-1
Illustrative Impact of Change in Heat Value

Heat Value at Export Delivery Point (MJ/m^3) (A)	NGTL Contract Volume (10^3m^3/d) (B)	Energy Equivalent (GJ) (AxB)		Downstream Energy Contract (GJ/d)
38.0	10,000	380,000	**Matched**	380,000
The heat value at the export delivery points changes from 38.0 MJ/m^3 to 37.8 MJ/m^3				
37.8	10,000	378,000	**Mismatched**	380,000

The heating value at the major export delivery points is relatively constant on an annual basis. The monthly volatility in heating value is shown in Table 3.2-2.

Table 3.2-2
Historical Actual Heat Values for the Major Export Delivery Points



Q4. What changes is NGTL proposing to its existing practices?

A4. NGTL is proposing to change contracts for service at export delivery points from volumetric units to energy units effective November 1, 2006 with a one time option for customers to adjust their contract quantity within a range of ±1%.

Q5. What is the purpose of this change?

A5. Contracting in energy units at export delivery points will provide customers with a fixed energy entitlement (currently customers have a variable energy entitlement) and will simplify administration and transactions for NGTL and its customers by aligning NGTL's contracting unit of measure with that of the pipelines and markets to which the Alberta System is connected. These pipelines and markets conduct their business in energy units.

This change will also help to standardize and simplify contracting for export capacity.

Q6. Which services will be affected by this conversion?

A6. Services affected by this conversion are FT-D, FT-DW, STFT, and IT-D.

Q7. Is contracting and transacting in energy units a common industry practice?

A7. Yes. Contracting in energy units is the practice of most of the gas transmission systems in North America.

In the mid-1990s, the Gas Industry Standards Board (now the North American Energy Standards Board) Standards Version 1.0 specified GJ/day as the standard quantity for nominations, confirmations, and scheduling transactions in Canada and dekatherm/day as the standard quantity unit for the United States.

Q8. What are the points at which NGTL has firm export delivery contracts?

A8. NGTL has firm export delivery contracts at the following points:

- Empress;
- Alberta/B.C.;
- McNeill; and
- Alberta/Montana.

Q9. What export pipelines are connected at these points and how are their contracts structured?

A9. The following export pipelines are connected to the Alberta System at the following points:

- Empress – TransCanada Mainline;
- Alberta/B.C. – TransCanada B.C. System;
- McNeill – Foothills Saskatchewan; and
- Alberta/Montana – NorthWestern Energy.

In 1998, the TransCanada Mainline fully converted its contracts to energy and TransCanada's B.C. System partially converted its contracts to energy. In December 2004, TransCanada PipeLines Limited applied to the National Energy Board (NEB) to complete energy conversion on the B.C. System. The NEB deferred its decision on this request until such time as Alberta System issues have been resolved and the Alberta System is able to convert to energy units. Foothills has initiated discussions with its shippers on the conversion of their volumetric contracts to energy units and intends to pursue energy conversion through collaborative discussions and/or through an application to the NEB. NorthWestern Energy, regulated by the Montana Public Service Commission, contracts in energy units.

Q10. Do other EUB regulated gas transmission pipelines in Alberta contract and transact in energy?

A10. Yes. ATCO Pipelines contracts delivery services and conducts transactions in energy units.

Q11. Do the other major downstream pipelines that are indirectly connected to the Alberta System contract in energy units?

A11. Yes. The major US pipelines are energy based pipelines. These include:

- Northern Border which connects to Foothills Saskatchewan to transport Western Canadian Sedimentary Basin (WCSB) gas from the Alberta System to the U.S. Midwest;
- Gas Transmission Northwest (GTN) which connects to the TransCanada B.C. System to transport WCSB gas from the Alberta System to the U.S. Pacific Northwest and California;
- Great Lakes Gas Transmission which connects to the Canadian Mainline to transport WCSB gas from the Alberta System to the U.S. Midwest and southern Ontario; and
- Iroquois Gas Transmission which connects to the Canadian Mainline to transport WCSB gas from the Alberta System to the U.S. Northeast.

Q12. Has NGTL taken any steps to date with respect to converting export delivery service contracts from volumetric units to energy units?

A12. Yes. NGTL has taken steps towards energy contracting by modifying communications with downstream pipeline operators to confirm quantities in GJs. In 2001, NGTL commenced posting a monthly heat value at three export delivery points (Alberta-B.C., McNeill, and Empress), as opposed to using daily measured heat values, whereby a customer's volume contract in a month would be operated and invoiced at the posted heat value. This posted heat value is determined from historical trends, projected throughput, and anticipated changes within the overall operation. In the event an unplanned operating incident occurs and a significant variance between posted and actual heat value results, NGTL may adjust the posted heat value mid-month. Using a posted heat value does provide some information stability but customers must still manage month to month variations.

NGTL has consulted with its customers, through the Tolls, Tariff, Facilities and Procedures Committee (TTFP) on the use of energy units rather than volumetric units for contracts for service at export delivery points. The TTFP was unable to reach consensus on this issue.

Q13. What is required to change contracts for service at export delivery points from volumetric units to energy units?

A13. The following steps are required:

- changing NGTL's Tariff to enable export delivery services to be contracted in energy;
- converting the export delivery service rate from a volumetric rate to an energy rate; and
- converting the units in existing export delivery contracts from volumetric units to energy units.

Q14. How will NGTL implement the conversion of existing export delivery service contracts from volumetric units to energy units?

A14. All contracts at each export delivery point will be converted based on the historical border-specific volume-weighted heat value for the period from January 1, 2004 to December 31, 2004 as shown in Table 3.2-3 below.

Table 3.2-3
Volume Weighted Heat Values
January 1, 2004-December 31, 2004

Export Delivery Point	**MJ/m^3**
Alberta- B.C. Border	37.98
Alberta-Montana Border	38.71
Boundary Lake Border	39.55
Cold Lake Border	37.52
Demmitt#2 Interconnect	39.57
Empress Border	37.52
Gordondale Border	40.05
McNeill Border	37.57
Unity Border	37.78

Prior to the conversion of the contracts from volumetric units to energy units, customers will have a one-time option to adjust their contract quantity within ±1%. This one-time option will enable customers to align their Alberta System contracts with downstream commercial arrangements and/or transportation contracts. Increases to customers' contract demand will be subject to availability of capacity. The Alberta System presently has sufficient capacity to accommodate changes to contract quantity for this conversion without building facilities. However, should circumstances change, NGTL would not build facilities to provide for this adjustment and available capacity will be allocated on a prorata basis.

Replacement contracts will be issued to customers on request or if a customer elects to adjust their contract quantity. If a new contract is not issued, the existing contracts will be deemed to be in energy.

If the Board approves NGTL's proposal, then it will, within 30 days of Board approval, inform all customers by letter of the changes in contracting practices and the implementation timeline. Customers will be required to notify NGTL by August 1, 2006 if they elect to adjust their contract quantity or if they want their contracts reissued after the implementation.

A copy of the Tariff changes required to effect energy conversion is included in Appendix 3A of this section. A detailed summary of these changes and a blacklined copy of the affected Tariff sections are included in Appendix 3B. The base document also includes the proposed housekeeping changes discussed in Section 3.3.

Q15. How will NGTL calculate the export delivery rate in energy units?

A15. For rate calculation purposes, the energy contracts will be converted to volume based on a 37.8 MJ/m^3 heating value. Appendix 3C of this section contains a revised rate calculation flow chart for 2005 illustrating the rates for the export delivery services in energy units.

Q16. How will the proposed changes impact Alberta System customers?

A16. As NGTL currently manages daily delivery transactions at export delivery points in energy units, this conversion will have minimal impact on customers from a daily transactional perspective. There will, however, be some minor impacts on the contract quantity at each export delivery point (since the contract quantity would be a fixed energy value as opposed to the current fixed volume value) and the associated energy rate and invoice related to the heat value used to convert the contracts from volume units to energy units. Table 3.2-4 illustrates these effects prior to possible adjustments to contract quantity provided for in the one time option that is outlined in Q/A 14.

Table 3.2-4
Illustrative Contract Quantity and Rate Impact

Border	Heat Value Jan/04 – Dec/04 (MJ/m^3)	Change in Contract Quantity (GJ/d)[1]	Change in Energy Rate and Invoice[2]
Empress	**37.5**	**0.0%**	**-0.7%**
McNeill	**37.6**	**0.0%**	**-0.6%**
AB-B.C.	**38.0**	**0.0%**	**+0.5%**
AB-Montana	**38.7**	**0.0%**	**+2.4%**

Notes:
[1] Contracts are converted at border specific rates.
[2] The illustrative 2005 FT-D rate of $\$5.504/10^3m^3$ is converted to \$0.1456/GJ using 37.8 MJ/m^3.

Q17. Will contracting for services in energy units have any financial impacts on existing customers?

A17. Yes. There will be a minor impact on export delivery customers. The impact on the FT-D rate at export delivery points ranges from a decrease of \$0.001/GJ at Empress to an increase of \$0.0007/GJ at Alberta-B.C.

Q18. Can the distributional effects on customers at the export delivery points be mitigated?

A18. Under the current rate design, NGTL uses a single uniform export delivery rate. Consequently, the distributional effects resulting from the calculation of rates in energy units cannot be mitigated, however, a transition period could be considered to mitigate the financial impact of the change.

Q19. When would NGTL implement the proposed changes?

A19. NGTL proposes to make the changes effective November 1, 2006 to align with the beginning of the gas year.

Q20. Please summarize the reasons that contracts for service at export delivery points should be converted from volume units to energy units?

A20. NGTL is out of step with the North American market. Most pipelines connected downstream of the Alberta System contract in energy. This conversion of contracts from volume units to energy units is the last step in a process that was begun with posted heat values in 2001. Completing the conversion will improve the efficiency of commercial and operational transactions for customers that utilize the Alberta System and downstream pipelines and avoid potential mismatches in contracted capacity that can result from fluctuations in heat content over time.

3.3 HOUSEKEEPING CHANGES

Q21. Please describe NGTL's proposed "housekeeping" amendments.

A21. NGTL proposes the following minor amendments:

- change all references from "Financial Information and Security" to "Financial Assurances", pursuant to Board Order U2004-376;
- change all references to the "Tolls, Tariff and Procedures (TTP) Committee" in Appendix H to the "Tolls, Tariff, Facilities and Procedures (TTFP) Committee";
- delete the definition of CPO from Appendix H due to a conflict with the definition of CPO in the General Terms and Conditions section of the NGTL Tariff. Additionally, a reference to Alberta Delivery Point and Alberta Extraction Point was added;
- include recent service additions (FT-RN, FT-DW, and LRS-3) in the appropriate Rate Schedules; and
- correct minor typographical errors.

A detailed summary of the proposed amendments, in addition to blacklined copies of the applicable Tariff pages, are provided in Appendix 3D of this section.

Q22. Does this conclude NGTL's written evidence on service and tariff amendments?

A22. Yes.

APPENDIX 3A: ENERGY CONVERSION TARIFF CHANGES (CLEAN COPY)

RATE SCHEDULE FT-D
FIRM TRANSPORTATION - DELIVERY

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule FT-D shall mean the delivery of gas to Customer at Customer's Export Delivery Points (the "Service"), which includes transportation of gas that Company determines necessary to provide services under the Tariff.

2.2 The Service is available to any Customer that has executed a Service Agreement and Schedule of Service under Rate Schedule FT-D. A standard form Service Agreement for Service under this Rate Schedule FT-D is attached.

3.0 PRICING

3.1 The rate used in calculating Customer's monthly demand charge under each of Customer's Schedules of Service for Service under Rate Schedule FT-D is the FT-D Demand Rate.

4.0 CHARGE FOR SERVICE

4.1 Aggregate of Customer’s Monthly Demand Charge

The aggregate of Customer’s monthly demand charges for a Billing Month for Service under Rate Schedule FT-D shall be equal to the sum of the monthly demand charges for each of Customer’s Schedules of Service under Rate Schedule FT-D, determined as follows:

$$MDC = \sum F \times \left(A \times \frac{B}{C} \right)$$

Where:

“MDC”	=	the aggregate of the demand charges applicable to such Schedule of Service for such Billing Month;
“F”	=	the FT-D Demand Rate;
“A”	=	each Export Delivery Contract Demand in effect for all or a portion of such Billing Month for such Schedule of Service;
“B”	=	the number of days in such Billing Month that Customer was entitled to such Export Delivery Contract Demand under such Schedule of Service; and
“C”	=	the number of days in such Billing Month.

4.2 Aggregate of Customer’s Surcharges

The aggregate of Customer’s Surcharges for a Billing Month shall be equal to the sum of all Surcharges set forth in the Table of Rates, Tolls and Charges applicable to each of Customer’s Schedules of Service under Rate Schedule FT-D.

4.3 Aggregate of Customer's Over-Run Gas Charges

The aggregate of Customer's charges for Over-Run Gas in a Billing Month for Service under Rate Schedule FT-D shall be equal to the sum of the monthly charges for Over-Run Gas for each Export Delivery Point at which Customer is entitled to Service under Rate Schedule FT-D, determined as follows:

MOC = Q x Z

Where:

"MOC"	=	the monthly charge for Over-Run Gas at the Export Delivery Point;
"Q"	=	total quantity of gas allocated to Customer by Company as Over-run Gas in accordance with paragraph 4.6 for Service under all Rate Schedules at such Export Delivery Point for the month preceding such Billing Month;
"Z"	=	the IT-D Rate at such Export Delivery Point.

4.4 The calculation of Customer's charge for Over-Run Gas in paragraph 4.3 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

4.5 Aggregate Charge For Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 4.1, 4.2, and 4.3.

4.6 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have

been nominated, the aggregate quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to Service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D;

(iv) fourthly to Service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to Customer under Rate Schedule IT-D at such Export Delivery Point. If Customer is not entitled to service under Rate Schedule IT-D at such Export Delivery Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 4.3.

5.0 TERM OF SERVICE

5.1 Term of a Schedule of Service

If, in the provision of new Service, Company determines that:

(i) no new Facilities are required that are directly attributable (generally mainline facilities) to Customer's request for such Service, the term of the Schedule of

Service shall be a term equal to the term requested by Customer with the minimum term being one (1) year; or

(ii) new Facilities are required that are directly attributable (generally mainline facilities) to Customer's request for such Service, the term of the Schedule of Service shall be equal to ten (10) years or such longer period that Company and Customer agree to.

5.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service for Service under Rate Schedule FT-D.

6.0 CAPACITY RELEASE

6.1 If Customer desires a reduction of Customer's Export Delivery Contract Demand for all or any portion of its Service under a Schedule of Service under Rate Schedule FT-D, Customer shall notify Company of its request for such reduction specifying the particular Export Delivery Point, Schedule of Service and the Export Delivery Contract Demand available to any other Person who requires Service under Rate Schedule FT-D. Company shall not have any obligation to find any Person to assume the Export Delivery Contract Demand Customer proposes to make available. If after notice is given to Company a Person is found who agrees to assume the Export Delivery Contract Demand Customer proposes to make available, together with any applicable Surcharge, Company may reduce Customer's Export Delivery Contract Demand under such Schedule of Service, on terms and conditions satisfactory to Company, by an amount equal to the Export Delivery Contract Demand specified in a new Schedule of Service, executed by Company and such Person. Notwithstanding such reduction, Customer shall at Company's sole option either:

(i) continue to pay any Surcharge until the Service Termination Date as described in the applicable Schedule of Service (unless any other Person acceptable to Company has agreed to pay such Surcharge); or

(ii) in the event that Company retires any Facilities required to provide such Service, pay to Company within the time determined by Company, an amount equal to the net book value of such Facilities adjusted for all costs and expenses associated with such retirement.

7.0 TRANSFER OF SERVICE

7.1 A Customer entitled to receive Service under Rate Schedule FT-D shall not be entitled to transfer all or any portion of Service under Rate Schedule FT-D to any Receipt Point or Delivery Point.

8.0 TERM SWAPS

8.1 A Customer entitled to receive Service under Rate Schedule FT-D shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate Schedule FT-D with the Service Termination Date under any Schedule of Service.

9.0 TITLE TRANSFERS

9.1 A Customer entitled to receive Service under Rate Schedule FT-D may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

10.0 RENEWAL OF SERVICE

10.1 Renewal Notification

Customer shall be entitled to renew all or any portion of Service under a Schedule of Service under Rate Schedule FT-D, if Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

10.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 10.1 shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial Assurances provisions in Article 10 of the General Terms and Conditions.

10.3 Renewal Term

Customer's notice shall specify a renewal term of not less than one (1) year consisting of increments of whole months.

11.0 APPLICATION FOR SERVICE

11.1 Applications for Service under this Rate Schedule FT-D shall be in such form as Company may prescribe from time to time.

12.0 GENERAL TERMS AND CONDITIONS

12.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule FT-D are applicable to Rate Schedule FT-D to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

SERVICE AGREEMENT

RATE SCHEDULE FT-D

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta (“Company”)

- and -

•, a body corporate having an office in •, • (“Customer”)

IN CONSIDERATION of the premises and the covenants and agreements in this Service Agreement, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule FT-D in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule FT-D.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule FT-D including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas quantity actually received or the aggregate gas quantity actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule FT-D, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix “F” of the Tariff shall be given via Company’s electronic bulletin board (“EBB”). Company shall not accept any such Notice for those matters listed in Appendix “F” via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule FT-D, the General Terms and Conditions and Schedule of Service under Rate Schedule FT-D are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE FT-D

CUSTOMER: •

Schedule of Service Number	Export Delivery Point Number and Name	Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Export Delivery Contract Demand GJ/d	Additional Conditions
•	• •	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE FT-DW

FIRM TRANSPORTATION – DELIVERY WINTER

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule FT-DW shall mean the delivery of gas to Customer at Customer's Export Delivery Points (the "Service"), which includes transportation of gas that Company determines necessary to provide services under the Tariff**.**

2.2 The Service is available to any Customer requiring the delivery of gas at designated Export Delivery Points during the Winter Season that has executed a Service Agreement and Schedule of Service under Rate Schedule FT-DW and Company has determined capacity shall be made available. Company shall not be required to construct or install Facilities for any Service under Rate Schedule FT-DW. A standard form Service Agreement for Service under this Rate Schedule FT-DW is attached.

3.0 PRICING

3.1 The rate used in calculating Customer's monthly demand charge under each of Customer's Schedules of Service for Service under Rate Schedule FT-DW is the FT-DW Demand Rate.

4.0 CHARGE FOR SERVICE

4.1 Aggregate of Customer's Monthly Demand Charge

The aggregate of Customer's monthly demand charges for a Billing Month for Service under Rate Schedule FT-DW shall be equal to the sum of the monthly demand charges for each of Customer's Schedules of Service under Rate Schedule FT-DW, determined as follows:

$$\text{MDC} = \sum F \times \left(A \times \frac{B}{C} \right)$$

Where:

"MDC"	=	the aggregate of the demand charges applicable to such Schedule of Service for such Billing Month;
"F"	=	the FT-DW Demand Rate;
"A"	=	each Export Delivery Contract Demand in effect for all or a portion of such Billing Month for such Schedule of Service;
"B"	=	the number of days in such Billing Month that Customer was entitled to such Export Delivery Contract Demand under such Schedule of Service; and
"C"	=	the number of days in such Billing Month.

4.2 Aggregate of Customer's Surcharges

The aggregate of Customer's Surcharges for a Billing Month shall be equal to the sum of all Surcharges set forth in the Table of Rates, Tolls and Charges applicable to each of Customer's Schedules of Service under Rate Schedule FT-DW.

4.3 Aggregate of Customer's Over-Run Gas Charges

The aggregate of Customer's charges for Over-Run Gas in a Billing Month for Service under Rate Schedule FT-DW shall be equal to the sum of the monthly charges for Over-Run Gas for each Export Delivery Point at which Customer is entitled to Service under Rate Schedule FT-DW, determined as follows:

MOC = Q x Z

Where:

"MOC"	=	the monthly charge for Over-Run Gas at the Export Delivery Point;
"Q"	=	total quantity of gas allocated to Customer by Company as Over-run Gas in accordance with paragraph 4.6 for Service under all Rate Schedules at such Export Delivery Point for the month preceding such Billing Month;
"Z"	=	the IT-D Rate at such Export Delivery Point.

4.4 The calculation of Customer's charge for Over-Run Gas in paragraph 4.3 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

4.5 Aggregate Charge For Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 4.1, 4.2, and 4.3.

4.6 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have

been nominated, the aggregate quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D;

(iv) fourthly to Service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to Customer under Rate Schedule IT-D at such Export Delivery Point. If Customer is not entitled to service under Rate Schedule IT-D at such Export Delivery Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 4.3.

5.0 TERM OF SERVICE

5.1 Initial Term of a Schedule of Service

The initial term for any Schedule of Service for Service under Rate Schedule FT-DW shall be four (4) consecutive Winter Seasons.

5.2 Renewal of Service

Customer may be entitled to renew all or a portion of Service under Rate Schedule FT-DW for a renewal term of two (2) consecutive Winter Seasons provided that:

(i) Customer has given written notice to Company of such renewal on or before October 31 of the year which is two (2) consecutive Winter Seasons prior to the Service Termination Date; and

(ii) Company determines capacity shall be made available.

If Customer does not provide such renewal notice and/or Company determines capacity is not available, the Service shall expire on the Service Termination Date.

5.3 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 5.2 shall be irrevocable two (2) consecutive Winter Seasons prior to the Service Termination Date.

Any renewal of Service is subject to the Financial Assurances provisions in Article 10 of the General Terms and Conditions.

5.4 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service for Service under Rate Schedule FT-DW.

6.0 CAPACITY RELEASE

6.1 A Customer entitled to receive Service under Rate Schedule FT-DW shall not be entitled to reduce Customer's FT-DW Contract Demand for all or any portion of its Service under a Schedule of Service under Rate Schedule FT-DW.

7.0 TRANSFER OF SERVICE

7.1 A Customer entitled to receive Service under Rate Schedule FT-DW shall not be entitled to transfer all or any portion of Service under Rate Schedule FT-DW to any Receipt Point or Delivery Point.

8.0 TERM SWAPS

8.1 A Customer entitled to receive Service under Rate Schedule FT-DW shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate Schedule FT-DW with the Service Termination Date under any Schedule of Service.

9.0 TITLE TRANSFERS

9.1 A Customer entitled to receive Service under Rate Schedule FT-DW may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

10.0 APPLICATION FOR SERVICE

10.1 Applications for Service under this Rate Schedule FT-DW shall be in such form as Company may prescribe from time to time.

11.0 GENERAL TERMS AND CONDITIONS

11.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule FT-DW are applicable to Rate Schedule FT-DW to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

SERVICE AGREEMENT

RATE SCHEDULE FT-DW

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta (“Company”)

- and -

•, a body corporate having an office in •, • (“Customer”)

IN CONSIDERATION of the premises and the covenants and agreements in this Service Agreement, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule FT-DW in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule FT-DW.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule FT-DW including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas quantity actually received or the aggregate gas quantity actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule FT-DW, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix "F" of the Tariff shall be given via Company's electronic bulletin board ("EBB"). Company shall not accept any such Notice for those matters listed in Appendix "F" via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule FT-DW, the General Terms and Conditions and Schedule of Service under Rate Schedule FT-DW are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE FT-DW

CUSTOMER: •

Schedule of Service Number	Export Delivery Point Number and Name	Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Export Delivery Contract Demand GJ/d	Additional Conditions
•	• •	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE STFT

SHORT TERM FIRM TRANSPORTATION - DELIVERY

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule STFT shall mean the delivery of gas to Customer at Customer's Export Delivery Points (the "Service") which includes the transportation of gas Company determines necessary to provide services under the Tariff.

2.2 The Service is available to any Customer requiring the delivery of gas at designated Export Delivery Points during the Winter Season provided that:

(a) Customer has executed a Service Agreement and Schedule of Service under Rate Schedule STFT;

(b) Customer, prior to the commencement of the bidding process set out in article 4.0, has provided Company with Financial Assurances as required by Company pursuant to article 10.0 of the General Terms and Conditions of the Tariff; and

(c) Company has accepted Customer's bid pursuant to article 4.0.

2.3 A standard form Service Agreement for Service under this Rate Schedule STFT is attached.

3.0 STFT CAPACITY AVAILABILITY DURING THE WINTER SEASON

3.1 Each month, commencing in July of each year Company will estimate the total firm delivery capacity existing in the Facilities at each of the Export Delivery Points that may be available during the Winter Season to Customers under this Rate Schedule STFT (the "STFT Capacity"). The STFT Capacity shall only include capacity that is available through Facilities that have been constructed to accommodate service under Rate Schedule FT-D.

3.2 Company will offer STFT Capacity (if any) available at each Export Delivery Point for the following terms:

(a) one (1) Month term for any Month during the Winter Season;

(b) three (3) consecutive Month term commencing December 1 of any year and ending on the last day of February in the next succeeding year; and

(c) five (5) consecutive Month term commencing November 1 of any year and ending on March 31 in the next succeeding year.

The terms described in subparagraphs (a), (b), and (c) are in each case referred to as a "Block Period".

4.0 THE BID PROCESS AND ALLOCATION OF STFT SERVICE

4.1 On or before the 25th day of each Month commencing with July of any year, Company shall notify Customers by notice posted on Company's electronic bulletin board of Company's estimate of available STFT Capacity at each of the Export Delivery Points for the applicable Block Period.

4.2 On or before the last day of the Month in which the Company posted the available STFT Capacity, the Customer may submit a bid for such available STFT Capacity in the form of the Schedule of Service attached as Exhibit "A" to the Service Agreement (the "Customer Bid"), to Company through Company's electronic bulletin board, or if not available, by fax.

4.3 Customer Bids once received by Company shall constitute an irrevocable binding offer on the part of Customer, which cannot be withdrawn. Company will determine, in accordance with article 6.0, which Customer Bids are accepted by Company and shall notify Customer through Company's electronic bulletin board, or if not available, by fax which, if any, of Customer's bids have been accepted.

4.4 Customer shall submit a separate Customer Bid for each separate combination of Export Delivery Point, STFT Bid Price, as defined in article 5.0, and Block Period. Customer shall not submit a Customer Bid for quantities greater than the available STFT Capacity being offered at each Export Delivery Point. Customer Bids which are not made in accordance with the terms of this Rate Schedule shall be rejected.

5.0 STFT BID PRICE

5.1 Each Customer Bid shall set out the bid price (the "STFT Bid Price") expressed in Canadian dollars and cents per gigaJoules per Month ($CDN/GJ/Month). The STFT Bid Price shall not be less than 135% of the applicable FT-D Demand Rate listed in the Table of Rates Tolls and Charges in effect on the day the Company receives the Customer Bid. In the event there is an increase or decrease to the FT-D Demand Rate after the Customer has submitted its Customer Bid, it is expressly agreed and understood that the STFT Bid Price shall be deemed to be increased or decreased as the case may be by an amount that maintains the same ratio of the STFT Bid Price to the FT-D Demand Rate as existed on the date Customer submitted its Customer Bid to Company.

6.0 ALLOCATION OF AVAILABLE STFT CAPACITY

6.1 Each Month upon receipt of Customer Bids, Company shall determine which Customer Bids are accepted and shall allocate STFT Capacity among Customers whose submitted Customer Bids were accepted by Company in the following manner:

(a) all Customer Bids for the particular Month, received by Company for a particular Export Delivery Point shall be ranked in descending order from the greatest to least quantity multiplier as determined in accordance with the following formula (the "Quantity Multiplier"):

QM = A x B

Where:

"QM" = the Customer's Quantity Multiplier;

"A" = the STFT Bid Price for a particular Customer Bid; and

"B" = the number of months in the Block Period for a particular Customer Bid.

(b) Company shall allocate available STFT Capacity at each Export Delivery Point to Customers submitting Customer Bids in descending order starting with the Customer Bids having the highest ranking, determined based upon the Quantity Multiplier until the available STFT Capacity has been allocated.

(c) In the event two (2) or more Customer Bids have the same ranking, determined in the manner provided for in subparagraph 6.1(a), then such Customer Bids will be ranked in descending order with the higher ranking being assigned to the Customer Bid which contains the highest STFT Bid Price for the shortest Block Period; provided however, if the STFT Bid Price and Block Period are identical and the available STFT Capacity is not sufficient to provide Service for the aggregate STFT Capacity requested, the available STFT Capacity at that Export Delivery Point shall be allocated on a pro rata basis among such Customers based on maximum STFT Capacity requested by each Customer in Customer's Bid.

(d) In the event that the pro rata share of the available STFT Capacity allocated to a Customer pursuant to subparagraph 6.1(c) above is less than the minimum STFT Capacity specified by such Customer in its Customer Bid, that Customer's Customer Bid will be rejected and the calculations under paragraph 6.1 shall be made excluding such Customer Bid.

(e) Company shall insert the STFT Capacity allocated to Customer on the Customer Bid and shall provide Customer with a copy of such Customer Bid.

7.0 CHARGE FOR SERVICE

7.1 Aggregate of Customer's Monthly Demand Charge

Customer's monthly demand charge for a Billing Month for Service made available under Rate Schedule STFT shall be equal to the aggregate of the products obtained by multiplying the applicable STFT Bid Price by the STFT Capacity allocated to such Customer for each Export Delivery Point as calculated by the application of the following formula:

MDC = A x B

Where:

"MDC" = the Customer's monthly demand charge;

"A" = the STFT Bid Price; and

"B" = the STFT Capacity allocated to such Customer in such Billing Month for Service under Rate Schedule STFT.

7.2 Aggregate of Customer's Over-Run Gas Charges

In the event that Company determines for a Billing Month that Company has delivered to Customer, in the month preceding such Billing Month, a quantity of gas at any Export Delivery Point in excess of the aggregate of the sum of:

(a) the products obtained when the STFT Capacity allocated to such Customer in respect of such Export Delivery Point is multiplied by the number of Days in the month preceding such Billing Month; and

(b) the sum of the products obtained when each of the Export Delivery Contract Demand in effect for Customer in respect of Rate Schedule FT-D in the month preceding such Billing Month is multiplied by the number of Days in such month that the Export Delivery Contract Demand was in effect,

then Customer shall pay to Company an amount equal to the product of such excess quantity and the applicable IT-D Rate.

7.3 Aggregate Charge for Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 7.1 and 7.2.

7.4 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to Service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D

(iv) fourthly to service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to Customer under Rate Schedule IT-D. If Customer is not entitled to service under Rate Schedule IT-D at such Export Delivery Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 7.2.

8.0 TERM OF SERVICE AGREEMENT

8.1 The term of a Service Agreement under Rate Schedule STFT shall commence on the first (1st) Day of the Month Company commences to provide Service to Customer pursuant to such Service Agreement and shall expire on the latest Service Termination Date set forth in Customer's Schedules of Service under such Service Agreement.

9.0 ASSIGNMENTS

9.1 The Customer shall not be entitled to assign any Schedule of Service under Rate Schedule STFT.

10.0 TITLE TRANSFERS

10.1 A Customer entitled to receive Service under Rate Schedule STFT may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

11.0 GENERAL TERMS AND CONDITIONS

11.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule STFT are applicable to Rate Schedule STFT to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

SERVICE AGREEMENT

RATE SCHEDULE STFT

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta (“Company”)

- and-

•, a body corporate having an office in •, • (“Customer”)

IN CONSIDERATION of the premises and the covenants and agreements herein contained, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule STFT in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule STFT.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule STFT including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas quantity actually received or the aggregate gas quantity actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as “Notice”) provided for in Rate Schedule STFT, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person’s address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix "F" of the Tariff shall be given via Company's electronic bulletin board ("EBB"). Company shall not accept any such Notice for those matters listed in Appendix "F" via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule STFT, the General Terms and Conditions and Schedule of Service under Rate Schedule STFT are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ____________________	Per : ____________________
Per: ____________________	Per : ____________________

SCHEDULE OF SERVICE
RATE SCHEDULE STFT

CUSTOMER: •

•
•
•

ATTENTION: •
PHONE: • FAX: •

Schedule of Service Number		Export Delivery Point Number and Name	Maximum STFT Capacity GJ/d	Minimum STFT Capacity GJ/d	Bid Price $/GJMonth	Block Period	Billing Commencement	Service Termination Date	Allocated STFT Capacity GJ/d
•	•	•	•	•	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE LRS
LOAD RETENTION SERVICE

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION

2.1 Subject to the stated terms and conditions, service under Rate Schedule LRS shall mean:

(i) the receipt of gas from Customer at Customer's Receipt Points as identified in Appendix "1" of this Rate Schedule; and

(ii) the delivery of gas to the Empress Border and/or the McNeill Border Export Delivery Points.

2.2 Subparagraphs (i) and (ii) are collectively referred to as the "Service" which includes transportation of gas that Company determines necessary to provide services under the Tariff.

2.3 A standard form Service Agreement for Service under this Rate Schedule LRS is attached.

3.0 AVAILABILITY

3.1 Service is available to those Customers who signed a precedent agreement with Palliser Pipeline Inc. prior to December 12, 1996 (the "Palliser Precedent Agreement") requiring firm service for the transportation of natural gas within Alberta. Service under Rate

Schedule LRS involves the receipt of quantities of gas at the Receipt Points authorized under this Rate Schedule LRS, being those Receipt Points identified in Appendix "1" attached to this Rate Schedule, and the delivery of such quantities of gas to either the Empress or McNeill Border Export Delivery Points. It is a condition of Service that Customers have or are deemed to have executed a Service Agreement and Schedule of Service under Rate Schedule LRS.

3.2 New or additional Service under Rate Schedule LRS at Receipt Points shall be made available in accordance with the provisions of article 5.0.

4.0 CHARGE FOR SERVICE

4.1 Aggregate of Customer's Monthly Receipt Demand Charge

The aggregate of Customer's monthly receipt demand charges for a Billing Month for Service under Rate Schedule LRS at Customer's Receipt Points as identified in Appendix "1" shall be equal to the sum of the monthly receipt demand charges for each of Customer's Schedules of Service under Rate Schedule LRS, determined as follows:

$$\text{MDC} = \sum (F \times P)\left(A \times \frac{B}{C}\right)$$

Where:

"MDC" = the aggregate of the receipt demand charges applicable to such Schedule of Service for such Billing Month;

"F" = the FT-R Demand Rate applicable to such Schedule of Service;

"P" = Price Point "A" (as defined in Rate Schedule FT-R);

"A" = each LRS Contract Demand in effect for all or a portion of such Billing Month as set out in such Schedule of Service;

"B"	=	the number of days in such Billing Month that Customer was entitled to such LRS Contract Demand under such Schedule of Service; and
"C"	=	the number of days in such Billing Month.

4.2 Determination of LRS Billing Adjustment

Customer's monthly LRS Billing Adjustment for a Billing Month for Service under Rate Schedule LRS shall be calculated by the application of the following four steps:

(i) determination of the Eligible LRS Contract Demand as described in subparagraph 4.2.1;

(ii) calculation of the amount that has been charged in respect of the Eligible LRS Contract Demand using the applicable FT-R Demand Rates and the volumetric equivalent of the FT-D Demand Rate as described in subparagraph 4.2.2;

(iii) calculation of the amount that should be charged in respect of Service under Rate Schedule LRS by applying the Effective LRS Rate to the Eligible LRS Contract Demand as described in subparagraph 4.2.3; and

(iv) determination of the LRS Billing Adjustment that will be applied to Customer's bill, as described in subparagraph 4.2.4, by determining the difference between the amounts calculated in steps (ii) and (iii).

4.2.1. <u>Determination of Eligible LRS Contract Demand</u>

Eligible LRS Contract Demand will be determined based on the information provided by Customer by way of an Officer's Certificate in such form as Company may prescribe from time to time. Eligibility is achieved only when Customer has provided a valid Officer's Certificate which satisfies Company that the requirements under Rate Schedule

LRS have been met. Customer shall provide an Officer's Certificate no later than the twenty-second (22nd) day of each Month.

The Eligible LRS Contract Demand will be determined as follows:

$$ECD = A - \left(\frac{B + C - D}{E}\right)$$

Where:

"ECD"	=	the Eligible LRS Contract Demand;
"A"	=	the aggregate LRS Contract Demand for Service under Rate Schedule LRS at the Customer's Receipt Points identified in Appendix "1" of this Rate Schedule adjusted as per paragraph 4.1;
"B"	=	the volumes of gas received by Company under Rate Schedule LRS verified by an Officer's Certificate to have been delivered from the Facilities into a storage facility for Customer;
"C"	=	the volumes of gas not verified by an Officer's Certificate to have been delivered to the Empress Border or McNeill Border Export Delivery Points under Rate Schedule LRS;
"D"	=	the volumes of gas under Rate Schedule LRS verified by an Officer's Certificate to have been delivered from a storage facility into the Facilities for Customer (provided that these storage volumes of gas originated from Customer's Receipt Points identified in Appendix "1" of this Rate Schedule for Customer) and were ultimately delivered to the Empress Border or McNeill Border Export Delivery Points; and
"E"	=	the average number of days in a month.

4.2.2. Calculation of Amount Charged in respect of the Eligible LRS Contract Demands using the FT-R Demand Rate(s) and the FT-D Demand Rate

After having determined the Eligible LRS Contract Demand, Company will calculate the amount that has been charged with respect to paragraph 4.1 of this Rate Schedule LRS. The amount that has been charged is the sum of:

(i) for all of Customer's Receipt Points identified in Appendix "1" the aggregate of the product of the FT-R Demand Rate and Price Point "A" and the Eligible LRS Contract Demand for each Receipt Point (the "Receipt Demand Charge"); and

(ii) the volumetric equivalent of the FT-D Demand Rate multiplied by the Eligible LRS Contract Demand (the "Delivery Demand Charge").

4.2.3. Calculation of the Amounts To Be Charged for LRS Service

The amount to be paid for Service under Rate Schedule LRS (the "LRS Charge") will be the product of the Effective LRS Rate and the Eligible LRS Contract Demand. The Effective LRS Rate is included in the Table of Rates, Tolls and Charges of this Tariff.

The Effective LRS Rate commences on January 1, 1998 and escalates at the rate of two (2) per cent per annum starting January 1, 1999.

4.2.4. Determination of LRS Billing Adjustment

The LRS Billing Adjustment will be calculated as follows:

(i) Company will calculate the sum of the Receipt Demand Charge and the Delivery Demand Charge; and

(ii) Company will calculate the difference between the LRS Charge and the amount calculated in accordance with subparagraph 4.2.4 (i).

The result of the calculations made in accordance with subparagraph 4.2.4 (ii) shall be the LRS Billing Adjustment.

Eligible LRS Contract Demand will not be considered for the determination of the LRS Billing Adjustment unless Customer has satisfied Company in the form of a valid Officer's Certificate, that the volumes of gas received were delivered to the Empress Border and McNeill Border Export Delivery Point within the Month with the exception of any volume of gas to have been delivered from Facilities into a storage facility.

4.3 Aggregate of Customer's Over-Run Gas Charges

4.3.1. In the event that Company determines in respect of a Billing Month that Company has received from Customer, in the month preceding such Billing Month, a volume of gas at any Receipt Point identified in Appendix "1" of this Rate Schedule in excess of:

(a) the aggregate of the products obtained when each of the LRS Contract Demand and LRS-3 Contract Demand in effect for Customer in respect of Rate Schedules LRS and LRS-3, in the month preceding such Billing Month, is multiplied by the number of Days in such month that such LRS Contract Demand and LRS-3 Contract Demand was in effect; plus

(b) the aggregate of the products obtained when each of the Receipt Contract Demand in effect for Customer in respect of Rate Schedule FT-R and Rate Schedule FT-RN, in the month preceding such Billing Month, is multiplied by the number of Days in such month that the Receipt Contract Demand was in effect,

then Customer shall pay to Company an amount equal to the product of a volume equal to such excess and the IT-R Rate for the applicable Receipt Point.

4.3.2. The calculation of Customer's Over-Run Gas charge in subparagraph 4.3.1 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

4.4 Aggregate Charge For Service

Customer shall pay for each Billing Month:

(i) the sum of

(a) the amounts calculated in accordance with paragraphs 4.1 and 4.3; and

(b) the amount, if any, calculated in accordance with article 7.0 of this Rate Schedule LRS; less

(ii) the sum of

(a) the billing credit, if any, calculated in accordance with the Terms and Conditions Respecting Relief for Mainline Capacity Restrictions in Appendix “B” of the Tariff; and

(b) the LRS Billing Adjustment, if any, calculated in accordance with paragraph 4.2 of this Rate Schedule LRS.

4.5 Allocation of Gas Received

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate volume of gas received from Customer at a Receipt Point shall be allocated for billing purposes as follows:

(i) first to Service to Customer under Rate Schedule LRS to a maximum of such Customer’s LRS Contract Demand for such Receipt Point under such Rate Schedule LRS, to service to a maximum of such Eligible LRS-2 Volumes for the Coleman Receipt Point under such Rate Schedule LRS-2 and to Service to Customer under Rate Schedule LRS-3 to a maximum of such Customer’s LRS-3 Contract Demand for such Receipt Point under such Rate Schedule LRS-3;

(ii) secondly to service to Customer under Rate Schedule FT-R to a maximum of such Customer's Receipt Contract Demand for such Receipt Point under such Rate Schedule FT-R;

(iii) thirdly to service to Customer under Rate Schedule FT-RN to a maximum of such Customer's Receipt Contract Demand for such Receipt Point under Rate Schedule FT-RN; and

(iv) fourthly to service to Customer under Rate Schedule IT-R at such Receipt Point. If Customer is not entitled to service under Rate Schedule IT-R at such Receipt Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 4.3.

5.0 AVAILABILITY OF NEW SERVICE

New Service under Rate Schedule LRS shall be made available to Customer receiving Service under this Rate Schedule LRS providing the following conditions are met:

(i) the Receipt Point location is south of Township 34 west of the 4th meridian and is east of range 29 west of the 4th meridian or is the East Calgary Receipt Point No. 2007;

(ii) if a new Receipt Point or if new Facilities are required at an existing Receipt Point, Customer has provided a capital contribution equal in amount to the capital costs associated with the installation or construction of any new Facilities;

(iii) gas received from Customer is for ultimate delivery to the Empress Border and/or McNeill Border Export Delivery Points;

(iv) Customer has signed a precedent agreement with Palliser Pipeline Inc. prior to December 12, 1996 (the "Palliser Precedent Agreement") requiring firm Service for the transportation of natural gas within Alberta; and

(v) the aggregate of Customer's Service under this Rate Schedule LRS shall not exceed the initial volumes and term set out in such Customer's Palliser Precedent Agreement and any additional volumes acquired by Customer pursuant to paragraph 12 of this Rate Schedule.

6.0 TERM OF SERVICE AGREEMENT

6.1 The term of a Service Agreement under Rate Schedule LRS shall expire on the date which is the latest Service Termination Date of Customer's LRS Receipt Point Obligations under such Service Agreement.

6.2 The initial term of an LRS Receipt Point Obligation in respect of any Customer Receipt Point identified in Appendix "1" shall be the period equal to the term set out in Customer's Palliser Precedent Agreement.

6.3 The term of an LRS Receipt Point Obligation in respect of any Customer Receipt Point, where new Service is obtained in accordance with the provisions of article 5.0 of this Rate Schedule, shall be a period equal to the term specified by Customer, provided that the minimum term that can be specified is one (1) year, (expressed in whole years) and provided that the Service Termination Date is no later than December 31, 2017.

7.0 SERVICE DURING TESTS

7.1 Customer may tender, for one (1) month in any calendar year, a daily volume of gas at a Receipt Point in excess of the aggregate of Customer's LRS Contract Demand under all of Customer's Schedules of Service for Service under Rate Schedule LRS at such Receipt Point, and Company will receive such excess volume pursuant to the terms and conditions applicable to this Rate Schedule LRS, provided that:

(a) Customer has first satisfied Company that it is a requirement under the terms of a gas purchase contract that Customer tender such excess volume to Company for the purpose of a test; and

(b) Company has determined in its sole judgment that it can receive such volume for such period without adversely affecting the operation of the Facilities or service to any other Customer receiving service under any Rate Schedule other than Rate Schedules IT-R, IT-D or IT-S.

7.2 The IT-R Rate for the applicable Receipt Point shall apply to excess volumes tendered under paragraph 7.1. Customer shall be charged for the excess in accordance with paragraph 4.3.

7.3 Notwithstanding the provisions of paragraph 7.1, Company in its sole discretion may interrupt or terminate the test at any time.

8.0 CAPACITY RELEASE

8.1 If Customer desires a reduction of Customer’s LRS Contract Demand for all or any portion of its Service under a Schedule of Service under Rate Schedule LRS Customer shall notify Company of its request for such reduction specifying the particular Receipt Point, Schedule of Service and the LRS Contract Demand available to any other Person qualifying for Service under Rate Schedule LRS. Company assumes no obligation to find such Person to assume the LRS Contract Demand that Customer proposes to make available. If after notice is given to Company a Person qualifying for Service under Rate Schedule LRS is found who agrees to assume the LRS Contract Demand Customer proposes to make available, Company may reduce Customer's LRS Contract Demand under such Schedule of Service, on terms and conditions satisfactory to Company, by an amount equal to the LRS Contract Demand specified in a Schedule of Service, executed by Company and such Person. Notwithstanding such reduction, Customer shall at Company’s sole option pay to Company within the time determined by Company an amount equal to the net book value of such Facilities in the event Company retires any Facilities required to provide such Service adjusted for all costs and expenses associated with such retirement.

9.0 RELIEF FOR MAINLINE RESTRICTIONS

9.1 Company may grant relief to a Customer entitled to Service under Rate Schedule LRS, in accordance with the Terms and Conditions Respecting Relief for Mainline Capacity Restrictions in Appendix "B" of the Tariff.

10.0 TRANSFER OF SERVICE BETWEEN RECEIPT POINTS

10.1 If Customer desires to transfer all or any portion of any Service under Rate Schedule LRS from one Receipt Point to another Receipt Point, Customer shall notify Company of its request for such transfer specifying the particular Receipt Points and the Service that Customer wishes to transfer.

10.2 Company shall not be required to permit the transfer requested in paragraph 10.1 if:

(i) the transferred-to Receipt Point location is north of Township 33 west of the 4th meridian and west of range 28 west of the 4th meridian except for the East Calgary Receipt Point No. 2007; or

(ii) Company is required to install or construct Facilities at a new Receipt Point to provide the Service requested unless Customer provides a capital contribution equal in amount to the capital costs associated with the installation or construction of new Facilities.

11.0 TITLE TRANSFERS

11.1 A Customer entitled to receive Service under Rate Schedule LRS may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

12.0 ASSIGNMENTS

12.1 Customer shall not be permitted to assign any Service Agreements or Schedule of Service pertaining to a LRS Contract Demand at a Receipt Point identified in Appendix "1" of this Rate Schedule unless such assignment is to an affiliate (as defined in the *Business Corporation Act*, (Alberta) S.A. 1981, c. B-15 as amended from time to time) or to another Customer entitled to receive Service under Rate Schedule LRS.

13.0 RENEWAL OF SERVICE

13.1 Provided the Customer shall have given Company notice advising Company that Customer desires to renew the term of all or a portion of any Service provided to Customer under this Rate Schedule LRS at least one (1) year prior to the expiry of the current term for which Company has agreed to provide such Service, Customer shall be entitled to renew such Service on a one time basis only for an additional term, which additional term:

(i) shall not exceed the initial term;

(ii) when added to the initial term shall not exceed twenty (20) years; and

(iii) shall not have a Service Termination Date later than December 31, 2017.

14.0 APPLICATION FOR SERVICE

14.1 Applications for Service under Rate Schedule LRS shall be in such form as Company may prescribe from time to time.

15.0 GENERAL TERMS AND CONDITIONS

15.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule LRS are applicable to Rate Schedule LRS to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

APPENDIX 1 TO RATE SCHEDULE LRS

RECEIPT POINT	STATION NUMBER
Alderson	1075
Atlee Buffalo East	1116
Atlee Buffalo South	1098
Atusis Creek	1792
Atusis Creek East	1792
Badger East	1275
Bantry NE	1296
Bantry North	1122
Bantry NW	1181
Bassano South	1330
Bassano South #2	1794
Berry-Carolside	1085
Berry Creek East	1136
Bowell South	1318
Bowmanton	1216
Carbon	1170
Cassils	1315
Cavalier	1737
Cessford Burfield West	1027
Cessford West	1012
Countess	1028
Countess South	1155
Countess South #2	2296
Countess West	1287
Countess Makepeace	1015
East Calgary	2007
Gatine	1623
Gayford	1358
Gem South	1435
Gem West	1490
Gleichen	1480
Hilda West	1402
Hussar Chancellor	1016
Iddlesleigh South	1277
Jenner West	1099
Lake Newell East	1210
Lonesome Lake	1768
Louisiana Lake	1366
Makepeace North	1419
Makepeace South	1419
Matzhiwin South	1379
Matzhiwin West	1150
Medicine Hat East	1186
Medicine Hat South #2	1043
Nightingale	1747

APPENDIX 1 TO RATE SCHEDULE LRS (continued)

Patricia West	1289
Princess South	1327
Princess West	1183
Rainier South	1378
Rainier SW	1380
Rosemary	1466
Rosemary North	1461
Schuler	1263
Standard	1534
Stanmore South	1156
Suffield	1202
Suffield East	1200
Suffield West	1423
Tide Lake	1348
Trochu	1574
Twelve Mile Coulee	1699
Vale	154
Vale East	1212
Verger	1056
Verger-Millicent	1203
Vulcan	1076
Wayne-Dalum	1039
Wayne-Rosebud	1107
Wintering Hills	1070

SERVICE AGREEMENT

RATE SCHEDULE LRS

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta (“Company”)

- and -

•, a body corporate having an office in •, • (“Customer”)

IN CONSIDERATION of the premises and the covenants and agreements herein contained, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule LRS in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule LRS.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to Rate Schedule LRS including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements;

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point in respect of which Customer has the right to receive Service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating volumes of gas received by Company among Company's Customers and to bind Customer in respect of all such data and information provided; and

(c) represent and demonstrate on a monthly basis that volumes moved under this service were delivered to either the Empress Border or McNeill Border Export Delivery Points. Should Customer not demonstrate as required, or should the demonstration be inadequate or found to be invalid, the resulting credit will not apply for the subject volumes and associated contract demands.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas volume actually received or the aggregate gas volume actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule LRS, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

•
•
•
Attention: •
Fax: •

Company:

•
•
•

Attention: Customer Account Representative
Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix "F" of the Tariff shall be given via Company's electronic bulletin board ("EBB"). Company shall not accept any such Notice for those matters listed in Appendix "F" via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule LRS, the General Terms and Conditions and Schedule of Service under Rate Schedule LRS are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of , • •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE LRS

CUSTOMER: •

Schedule of Service Number	Receipt Point Number and Name	Legal Description	Maximum Receipt Pressure kPa	Service Termination Date	LRS Contract Demand $10^3m^3/d$	LRS Term	Additional Conditions
•	•	•	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE LRS-2

LOAD RETENTION SERVICE - 2

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule LRS-2 shall mean:

(i) the daily receipt of gas from LRS-2 Customer at the Coleman receipt point located at SW-l/4-12-08-05-W5M (the "Coleman Receipt Point");

(ii) the daily transportation of such gas through the Facilities; and

(iii) the daily delivery of such gas to LRS-2 Customer at the Alberta-British Columbia export delivery point located at LSD-12-08-05-W5M (the "A/BC Export Delivery Point").

Subparagraphs (i), (ii) and (iii) are collectively referred to as the "Service".

2.2 The Service is available to Northstar Energy Corporation and assignees of it (the "LRS-2 Customer") provided the assignment complies with article 9.0. It is a condition of Service that LRS-2 Customer has executed a Service Agreement and Schedule of Service under Rate Schedule LRS-2. A standard form Service Agreement for Service under this Rate Schedule LRS-2 is attached.

3.0 SERVICE ENTITLEMENT

3.1 Company shall provide LRS-2 Customer with gas transportation service up to:

(i) 1127 10^3m^3/d (40 MMcf/d) from date of commencement of Service under Rate Schedule LRS-2 to December 31, 1999;

(ii) 1550 10^3m^3/d (55 MMcf/d) from January 1, 2000 to December 31, 2000;

(iii) 2113 10^3m^3/d (75 MMcf/d) from January 1, 2001 to December 31, 2001; and

(iv) 2817 10^3m^3/d (100 MMcf/d) from January 1, 2002 to October 31, 2013.

The amount identified in each of the subparagraphs (i) through (iv) shall, for the applicable period, be referred to as the "Maximum Eligible LRS-2 Volume".

3.2 LRS-2 Customer shall be entitled to increase its then current entitlement to LRS-2 from time to time by giving Company four (4) months prior written notice of the desired increase, provided that any such increase shall not result at any time in the LRS-2 Customer's entitlement to Service under Rate Schedule LRS-2 exceeding the Maximum Eligible LRS-2 Volume in effect at the end of such four (4) month notice period. LRS-2 Customer's entitlement to Service under Rate Schedule LRS-2, at any point in time, determined in accordance with this paragraph 3.2, shall be referred to as "Service Entitlement". LRS-2 Customer's initial Service Entitlement shall be 1127 10^3m^3/d (40 MMcf/d), and LRS-2 Customer's Service Entitlement shall never be less than be 1127 10^3m^3/d (40 MMcf/d).

4.0 CHARGE FOR SERVICE

4.1 Determination of Monthly Charge

LRS-2 Customer will be charged and shall pay a monthly amount (the "Monthly Charge") for a Billing Month equal to the sum for all days of such month of the following amounts:

(i) the daily equivalent of the FT-R Demand Rate at the Coleman Receipt Point multiplied by Price Point "A" (as defined in Rate Schedule FT-R) multiplied by the Service Entitlement for the day in the Billing Month; and

(ii) the daily volumetric equivalent of the FT-D Demand Rate at the A/BC Export Delivery Point multiplied by the Service Entitlement for the day in the Billing Month.

4.2 Determination of the LRS-2 Adjustment

The LRS-2 Adjustment for a Billing Month shall be equal to the Monthly Charge for such Billing Month less $50,000. The LRS-2 Adjustment shall then be applied against LRS-2 Customer's invoice issued in the second month following the Billing Month.

4.3 Determination of Eligible LRS-2 Volume

4.3.1 Officer's Certificate

LRS-2 Customer shall provide Company with a valid officer's certificate setting out the Eligible LRS-2 Volume for each day in a Billing Month, in such form as Company may prescribe from time to time (the "Officer's Certificate") on or before the last day of the month following the Billing Month, for purposes of determining the Eligible LRS-2 Volume.

4.3.2 Eligible LRS-2 Volume

The volume of gas eligible for Service under this Rate Schedule LRS-2 (the "Eligible LRS-2 Volume") for each day, as set forth in the Officer's Certificate, shall be equal to the lesser of:

(i) the actual volume of gas received by Company from LRS-2 Customer at the Coleman Receipt Point on each day in a Billing Month up to the Service Entitlement; and

(ii) the actual volumetric equivalent of LRS-2 Customer's allocation of gas to be delivered to the A/BC Export Delivery Point for Service under Rate Schedule LRS-2 on such day up to the Service Entitlement.

In the event that LRS-2 Customer fails to provide Company with an Officer's Certificate as provided herein, the Eligible LRS-2 Volume shall be deemed to be zero.

4.4 Allocation of Gas

4.4.1 Allocation of Gas Received

Notwithstanding any other provision of Rate Schedule LRS-2, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate daily volume of gas received from LRS-2 Customer at the Coleman Receipt Point shall be allocated for billing purposes as follows:

(i) first to Service to LRS-2 Customer under Rate Schedule LRS-2, to a maximum of Eligible LRS-2 Volumes for the Coleman Receipt Point under Rate Schedule LRS-2;

(ii) secondly to service to LRS-2 Customer under Rate Schedule FT-R to a maximum of such Customer's Receipt Contract Demand for such Coleman Receipt Point under such Rate Schedule FT-R;

(iii) thirdly to service to LRS-2 Customer under Rate Schedule FT-RN to a maximum of such Customer's Receipt Contract Demand for such Coleman Receipt Point under Rate Schedule FT-RN; and

(iv) fourthly to service to LRS-2 Customer under Rate Schedule IT-R for such Coleman Receipt Point. If LRS-2 Customer is not entitled to service under Rate Schedule IT-R at such Coleman Receipt Point, LRS-2 Customer shall be deemed to have been entitled to such service for the purposes of this subparagraph 4.4.1 (iii) and shall pay to Company an amount determined under article 4.0 of Rate Schedule IT-R for the volumes allocated under this subparagraph 4.4.1 (iii).

4.4.2 Allocation of Gas Delivered

Notwithstanding any other provision of Rate Schedule LRS-2, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate daily quantity of gas delivered to LRS-2 Customer at the A/BC Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to Service to LRS-2 Customer under Rate Schedule LRS-2 to a maximum of Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to LRS-2 Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract demand for such A/BC Export Delivery Point under such Rate Schedule FT-D;

(iv) forthly to service to LRS-2 Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract demand for such A/BC Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to LRS-2 Customer under Rate Schedule IT-D for such A/BC Export Delivery Point. If LRS-2 Customer is not entitled to service under Rate Schedule IT-D at such A/BC Export Delivery Point, LRS-2 Customer shall be deemed to have been entitled to such service for the purposes of this subparagraph 4.4.2 (v) and shall pay to Company an amount determined under article 4.0 of Rate Schedule IT-D for the quantities allocated under this subparagraph 4.4.2 (v).

5.0 TERM OF SERVICE AGREEMENT

5.1 The term of the Service Agreement under Rate Schedule LRS-2 shall commence on the effective date of the Board's Order approving Service under Rate Schedule LRS-2 and shall expire on October 31, 2013, provided however nothing herein shall relieve LRS-2 Customer or Company from any obligation which arose or accrued on or prior to October 31, 2013; and further provided that the LRS-2 Adjustments for the last two Billing Months of the Service Agreement under Rate Schedule LRS-2 shall be paid by the Company to LRS-2 Customer on or before December 31, 2013.

6.0 TRANSFER OF LRS-2 SERVICE

6.1 LRS-2 Customer shall not be entitled to transfer all or any portion of Service under Rate Schedule LRS-2 to any other Receipt Point or Delivery Point. LRS-2 Customer shall not be entitled to convert Service under Rate Schedule LRS-2 to any other service under any other Rate Schedule.

7.0 TERM SWAP OF LRS-2 SERVICE

7.1 LRS-2 Customer entitled to receive Service under Rate Schedule LRS-2 shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate

Schedule LRS-2 with the Service Termination Date under any Schedule of Service.

8.0 TITLE TRANSFERS

8.1 LRS-2 Customer shall not be entitled to transfer or accept a transfer of Customer's Inventory to or from any other Customer.

9.0 ASSIGNMENTS

9.1 LRS-2 Customer shall only be permitted to assign Service under Rate Schedule LRS-2 under the following conditions:

(i) such assignment is to an affiliate as defined by the *Business Corporations Act*, (Alberta) S.A. 1981, c.B-15 as amended from time to time; or

(ii) in the event that LRS-2 Customer divests all or a portion of its interest in the Coleman gas plant or the reserves which supply such plant, then LRS-2 Customer shall be entitled to assign all or any portion of its Service under Rate Schedule LRS-2 to the party acquiring such interest provided however;

(a) such assignment does not increase Company's administrative costs related to the provision of Service under Rate Schedule LRS-2 as determined by Company acting reasonably; and

(b) Company shall only be required to deal with one (1) party with respect to any matter regarding the Service under Rate Schedule LRS-2.

10.0 RENEWAL OF SERVICE

10.1 LRS-2 Customer shall not be entitled to renew Service under Rate Schedule LRS-2.

11.0 GAS USED

11.1 In respect of quantities that are transported utilizing Service under Rate Schedule LRS-2, LRS-2 Customer shall not be charged for nor shall any deduction be made for that portion of Gas Used which is attributable to gas used for compression. In respect of quantities that are transported utilizing Service under Rate Schedule LRS-2, Company shall also not charge LRS-2 Customer nor shall it make any deduction for that portion of Gas Used which is attributable to gas used for heating and pipeline losses until Company's systems are capable of separating Gas Used into the following components:

(i) gas used for compression;

(ii) gas used for heating; and

(iii) pipeline losses.

12.0 AUDIT RIGHTS

12.1 Company shall be entitled to audit, at its sole discretion and expense, at any time it determines necessary, any and all documents related to any Officer's Certificate and the contents thereof, in order to verify the accuracy of such Officer's Certificate, provided that any such audit shall be carried out within 24 months of the month to which such Officer's Certificate relates.

13.0 PRIORITY DURING INTERRUPTIONS

13.1 For the purposes of paragraph 11.4 of the General Terms and Conditions of the Tariff, Service under Rate Schedule LRS-2 shall have equal priority to service under Rate Schedule FT-R, FT-RN, FT-P, FT-A, FT-X, STFT, LRS, LRS-3, FT-D and FT-DW as the case may be.

14.0 GENERAL TERMS AND CONDITIONS

14.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule LRS-2 are applicable to Rate Schedule LRS-2 to the extent that such terms and conditions and provisions are not inconsistent with Rate Schedule LRS-2.

SERVICE AGREEMENT

RATE SCHEDULE LRS-2

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta (“Company”)

- and -

•, a body corporate having an office in •, • (“Customer”)

IN CONSIDERATION of the premises and the covenants and agreements herein contained, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule LRS-2 in accordance with the attached Schedules of Service. The Service will commence on the effective date of the Board’s Order approving Service under Rate Schedule LRS-2 and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule LRS-2.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to Rate Schedule LRS-2 including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point or downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating quantities of gas received or delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided; and

(c) provide the Officer's Certificate as defined in 4.3.1 of Rate Schedule LRS-2. If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas quantity actually received or the aggregate gas quantity actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule LRS-2, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

•

•

•

Attention: •

Fax: •

Company:

•

•

•

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix “F” of the Tariff shall be given via Company’s electronic bulletin board (“EBB”). Company shall not accept any such Notice for those matters listed in Appendix “F” via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule LRS-2, the General Terms and Conditions and Schedule of Service under Rate Schedule LRS-2 are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE LRS-2

CUSTOMER: •

Schedule of Service Number	Receipt Point Number and Name / Export Delivery Point Number and Name	Legal Descriptions	Maximum Receipt / Export Delivery Pressures kPa	Service Termination Date	LRS-2 Contract Demand $10^3m^3/d$	Additional Conditions
•	2003 Coleman	SW-12-008-05-W5	6205	October 31, 2013	•	•
	2001 Alberta - BC Border	09-11-008-05-W5	6205			

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE LRS-3

LOAD RETENTION SERVICE - 3

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION

2.1 Subject to the stated terms and conditions, service under Rate Schedule LRS-3 shall mean:

(i) the receipt of gas from Customer at Customer's Receipt Points as identified in Appendix "1" of this Rate Schedule and any new Receipt Points made available in accordance with Article 5.0 (the "LRS-3 Receipt Points"); and

(ii) the delivery of gas to the Empress Border Export Delivery Point.

2.2 Subparagraphs (i) and (ii) are collectively referred to as the "Service" which includes transportation of gas that Company determines necessary to provide services under the Tariff.

2.3 A standard form Service Agreement for Service under this Rate Schedule LRS-3 is attached.

3.0 AVAILABILITY

3.1 Service is available to Petro-Canada Oil and Gas, a general partnership ("Petro-Canada") and any assignees thereof in accordance with Article 11.0. It is a condition of Service that Customers have or are deemed to have executed a Service Agreement and Schedule of Service under Rate Schedule LRS-3. The aggregate LRS-3 Contract Demand shall not exceed 1410.0 $10^3m^3/d$ (50 MMcf/d).

3.2 New LRS-3 Receipt Points or additional Facilities required at existing Receipt Points for Service under Rate Schedule LRS-3 shall be made available in accordance with the provisions of Article 5.0.

4.0 CHARGE FOR SERVICE

4.1 Aggregate of Customer's Monthly Receipt Demand Charge

The aggregate of Customer's monthly receipt demand charges for a Billing Month for Service under Rate Schedule LRS-3 at Customer's LRS-3 Receipt Points shall be equal to the sum of the monthly receipt demand charges for each of Customer's Schedules of Service under Rate Schedule LRS-3, determined as follows:

$$MDC = \sum (F \times P)\left(A \times \frac{B}{C}\right)$$

Where:

"MDC"	=	the aggregate of the receipt demand charges applicable to such Schedule of Service for such Billing Month;
"F"	=	the FT-R Demand Rate applicable to such Schedule of Service;
"P"	=	the applicable Price Point in such Schedule of Service (as defined in Rate Schedule FT-R);
"A"	=	each LRS-3 Contract Demand in effect for all or a portion of such Billing Month as set out in such Schedule of Service;

"B"	=	the number of days in such Billing Month that Customer was entitled to such LRS-3 Contract Demand under such Schedule of Service; and
"C"	=	the number of days in such Billing Month.

4.2 Determination of LRS-3 Billing Adjustment

Customer's monthly billing adjustment for a Billing Month for Service under Rate Schedule LRS-3 (the "LRS-3 Billing Adjustment") shall be calculated as follows:

(i) determine the Eligible LRS-3 Contract Demand as described in subparagraph 4.2.1;

(ii) determine the amount that should be charged in respect of Service under Rate Schedule LRS-3 by applying the LRS-3 Rate to the Eligible LRS-3 Contract Demand as described in subparagraph 4.2.2;

(iii) determine the amount that has been charged in respect of the Eligible LRS-3 Contract Demand using the applicable FT-R Demand Rates and the volumetric equivalent of the FT-D Demand Rate as described in subparagraph 4.2.3;

(iv) during the Initial LRS-3 Term, determine the amount that should be adjusted in respect of charges for Service under Rate Schedule IT-R and Over-run Gas at the LRS-3 Receipt Points as described in subparagraph 4.2.4; and

(v) determine the LRS-3 Billing Adjustment that will be applied to Customer's invoice, as described in subparagraph 4.2.5.

4.2.1. <u>Determination of Eligible LRS-3 Contract Demand</u>

Eligible LRS-3 contract demand for each LRS-3 Receipt Point (the "Eligible LRS-3 Contract Demand") shall be determined by Company as follows:

$$\text{ECD} = \frac{\left(\text{EV} \times \dfrac{\text{DV}}{\text{ADV}}\right)}{\text{E}}$$

Where:

"ECD"	=	the Eligible LRS-3 Contract Demand for such LRS-3 Receipt Point;
"EV"	=	the Eligible LRS-3 Volume as defined below in this paragraph;
"DV"	=	the Deemed LRS-3 Volume as defined below in this paragraph;
"ADV"	=	the aggregate of Deemed LRS-3 Volume for all LRS-3 Receipt Points; and
"E"	=	the number of days in the month preceding such Billing Month.

The eligible LRS-3 volume for Service under Rate Schedule LRS-3 for such Billing Month (the "Eligible LRS-3 Volume") shall be the lesser of:

(i) the aggregate actual volume of gas delivered by Company for Customer under all Schedules of Service for Service under all Rate Schedules at the Empress Border Export Delivery Point for the month preceding such Billing Month;

(ii) the aggregate of Customer's LRS-3 Contract Demand in effect for the month preceding such Billing Month multiplied by the number of days in the month preceding such Billing Month that Customer was entitled to such Service under Rate Schedule LRS-3 at each of Customer's LRS-3 Receipt Point (the "Available LRS-3 Volumes"); and

(iii) the aggregate of the volume of gas deemed to be received by Company for Customer for Service under Rate Schedule LRS-3 for the month preceding such Billing Month that shall be equal to the sum of the deemed LRS-3 volume of gas at each of Customer's LRS-3 Receipt Points (the "Deemed LRS-3 Volume"), determined by Company as follows:

DV = AV + (IT x C)

Where:

"DV' = the Deemed LRS-3 Volume applicable to such LRS-3 Receipt Point;

"AV" = the actual volume of gas received by Company for Customer under Schedules of Service for Service under Rate Schedule LRS-3 at such LRS-3 Receipt Point (the "Actual LRS-3 Volume"); and

"IT" = during the Initial LRS-3 Term, the aggregate volume of gas received by Company for Customer for Service under Rate Schedule IT-R plus Over-run Gas at all of Customer's LRS-3 Receipt Points which is deemed to be re-allocated to Service under Rate Schedule LRS-3 as determined by Company shall be the lesser of:

a) the aggregate Available LRS-3 Volume for such LRS-3 Receipt Point less the aggregate Actual LRS-3 Volume for all of Customer's LRS-3 Receipt Points (the "Unutilized LRS-3 Volume"); and

b) the aggregate of actual volume of gas received by Company for Customer for Service under Rate Schedule IT-R and Over-run Gas as allocated by Company to Customer at all of Customer's LRS-3 Receipt Points; and

"C" = the percentage of IT to be re-allocated to such LRS-3 Receipt Point on a pro-rata basis, based on Unutilized LRS-3 Volume.

During the Secondary LRS-3 Term, IT shall be deemed to be zero.

4.2.2. Determination of Amounts To Be Charged in respect of Eligible LRS-3 Contract Demand

The amount to be paid for Service under Rate Schedule LRS-3 (the "LRS-3 Charge") will be the product of the LRS-3 Demand Rate and the aggregate Eligible LRS-3 Contract Demand.

4.2.3. Determination of Customer's Monthly Charge in respect of the Eligible LRS-3 Contract Demands using the FT-R Demand Rate(s) and the FT-D Demand Rate

Company will calculate an amount that is deemed to be the amount charged in the month preceding the Billing Month with respect to the Eligible LRS-3 Contract Demand determined in subparagraph 4.2.1. Such deemed amount shall be the sum of:

(i) for all of Customer's LRS-3 Receipt Points, the aggregate of the product of the FT-R Demand Rate, the applicable Price Point and the Eligible LRS-3 Contract Demand for each LRS-3 Receipt Point (the "LRS-3 Receipt Demand Charge"); and

(ii) the volumetric equivalent of the FT-D Demand Rate multiplied by the aggregate Eligible LRS-3 Contract Demand (the "LRS-3 Delivery Demand Charge").

4.2.4. Determination of Adjustments with respect to IT-R and Over-run Gas Charges

During the Initial LRS-3 Term, Company will determine a monthly commodity charge adjustment for a Billing Month in respect of charges for Service under Rate Schedule IT-R and Over-run Gas at the LRS-3 Receipt Points, determined as follows:

$$MA = A - [(B - C) \times D]$$

Where:

"MA" = the monthly commodity charge adjustment applicable to such Billing Month;

“A” = the aggregate of Customer’s monthly charges for Service under Rate Schedule IT-R and the aggregate of Customer’s Over-run Gas charges for all LRS-3 Receipt Points for the month preceding such Billing Month;

“B” = the aggregate of the actual volume of gas received by Company for Customer for Service under Rate Schedule IT-R and Over-run Gas as allocated by Company to Customer at all of Customer’s LRS-3 Receipt Points for the month preceding such Billing Month;

“C” = IT as defined in subparagraph 4.2.1; and

“D” = the IT-R Rate at Bowmanton Receipt Point No. 1216.

During the Secondary LRS-3 Term, the commodity charge adjustment shall be deemed to be zero.

4.2.5. Determination of LRS-3 Billing Adjustment

The LRS-3 Billing Adjustment will be calculated by subtracting the aggregate amounts calculated in subparagraphs 4.2.3 and 4.2.4 from the aggregate amount calculated in subparagraph 4.2.2. The LRS-3 Billing Adjustment will be refunded in the second month following such Billing Month.

If during the Initial LRS-3 Term, the LRS-3 Billing Adjustment calculated pursuant to this paragraph is determined to be a positive number, the LRS-3 Billing Adjustment will be deemed to be zero.

4.3 Aggregate of Customer’s Over-Run Gas Charges

4.3.1. The aggregate of Customer’s charges for Over-Run Gas in a Billing Month for Service under all Rate Schedules shall be equal to the sum of the monthly charges for Over-Run Gas for each Receipt Point at which Customer is entitled to Service under any Rate Schedule, determined as follows:

MOC = V x Z

Where:

"MOC" = the monthly charge for Over-Run Gas at such Receipt Point;

"V" = total volume of gas allocated to Customer by Company as Over-run Gas in accordance with paragraph 4.5 for Service under all Rate Schedules at such Receipt Point for the month preceding such Billing Month; and

"Z" = the IT-R Rate at such Receipt Point.

4.3.2. The calculation of Customer's Over-Run Gas charge in subparagraph 4.3.1 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

4.4 Aggregate Charge For Service

Customer shall pay for each Billing Month:

(i) the sum of the amounts calculated in accordance with paragraphs 4.1 and 4.3; less

(ii) the sum of

(a) the billing credit, if any, calculated in accordance with the Terms and Conditions Respecting Relief for Mainline Capacity Restrictions in Appendix "B" of the Tariff; and

(b) the LRS-3 Billing Adjustment, if any, calculated in accordance with paragraph 4.2 of this Rate Schedule LRS-3.

4.5 Allocation of Gas Received

Notwithstanding any other provision of this LRS-3 Rate Schedule, any Service Agreement or General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate volume of gas received from Customer at a Receipt Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedules LRS and LRS-3 to a maximum of such Customer's LRS Contract Demand for such Receipt Point under such Rate Schedule LRS and to a maximum of such Customer's LRS-3 Contract Demand for such Receipt Point under such Rate Schedule LRS-3;

(ii) secondly to service to Customer under Rate Schedule FT-R to a maximum of such Customer's Receipt Contract Demand for such Receipt Point under such Rate Schedule FT-R;

(iii) thirdly to service to Customer under Rate Schedule FT-RN to a maximum of such Customer's Receipt Contract Demand for such Receipt Point under Rate Schedule FT-RN; and

(iv) fourthly to service to Customer under Rate Schedule IT-R at such Receipt Point. If Customer is not entitled to service under Rate Schedule IT-R at such Receipt Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 4.3.

5.0 AVAILABILITY OF NEW LRS-3 RECEIPT POINTS

New LRS-3 Receipt Points or new Facilities at existing Receipt Points required for Service under Rate Schedule LRS-3 shall be made available to Customer receiving Service under this Rate Schedule LRS-3 providing the following conditions are met:

(i) the LRS-3 Receipt Point location is on the Company's Facilities between the Bowmanton Receipt Point No. 1216 and the Empress Border Export Delivery Point;

(ii) Customer has provided a capital contribution equal in amount to the capital costs associated with the installation or construction of any new LRS-3 Receipt Point or any new Facilities required at an existing Receipt Point;

(iii) gas received from Customer is for ultimate delivery to the Empress Border Export Delivery Point; and

(iv) Customer requests a transfer of Service pursuant to Article 9.0 for LRS-3 Contract Demand applicable to the Customer's request for new LRS-3 Receipt Points or new Facilities at an existing Receipt Point.

6.0 TERM OF SERVICE AGREEMENT

6.1 Initial Term

The initial term of the Service Agreement and Schedules of Service for Service under Rate Schedule LRS-3 shall be four (4) years commencing on the Billing Commencement Date and shall terminate on the Service Termination Date (the "Initial LRS-3 Term").

6.2 Renewal of Service

Customer shall be entitled to renew all or a portion of Service under Rate Schedule LRS-3 at the end of the Initial LRS-3 Term or any time after the Initial LRS-3 Term (such renewal period here is the "Secondary LRS-3 Term") provided that:

(i) Customer has given Company twelve (12) months prior written notice; and

(ii) the renewal volume specified by Customer for each Schedule of Service for Service under Rate Schedule LRS-3 shall be less than or equal to LRS-3 Contract Demand for such Schedule of Service.

Any renewal of Service is subject to the Financial Assurances provisions in Article 10.0 of the General Terms and Conditions.

6.3 Irrevocable Renewal Notice

Customer's notice to renew pursuant to paragraph 6.2 shall be irrevocable twelve (12) months prior to the Service Termination Date.

6.4 Renewal Term

Customer's renewal notice shall specify a renewal term that:

(i) shall be a minimum of one (1) year consisting of increments of whole months; and

(ii) shall have a Termination Date no later that twenty (20) years from the Billing Commencement Date of the Initial LRS-3 Term.

6.5 Termination

Customer shall be entitled to terminate the Service Agreement in whole and not in part at the end of the Initial LRS-3 Term or any time after the Initial LRS-3 Term provided that Customer gives Company twelve (12) months prior written notice. If Customer does not provide such termination notice to Company, Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedule of Service for Service under Rate Schedule LRS-3.

7.0 CAPACITY RELEASE

7.1 A Customer entitled to receive Service under Rate Schedule LRS-3 shall not be entitled to reduce Customer's LRS-3 Contract Demand for all or any portion of its Service under a Schedule of Service under Rate Schedule LRS-3.

8.0 RELIEF FOR MAINLINE RESTRICTIONS

8.1 Company may grant relief to a Customer entitled to Service under Rate Schedule LRS-3, in accordance with the Terms and Conditions Respecting Relief for Mainline Capacity Restrictions in Appendix "B" of the Tariff.

9.0 TRANSFER OF SERVICE BETWEEN RECEIPT POINTS

9.1 If Customer desires to transfer all or any portion of any Service under Rate Schedule LRS-3 from one LRS-3 Receipt Point to another LRS-3 Receipt Point, Customer shall notify Company of its request for such transfer specifying the particular LRS-3 Receipt Points and the Service that Customer wishes to transfer.

9.2 Company is under no obligation to permit the transfer requested in paragraph 9.1, but may permit such transfer provided that:

(i) the transferred-to LRS-3 Receipt Point location is on the Company's Facilities between the Bowmanton Receipt Point No. 1216 and the Empress Border Export Delivery Point; and

(ii) if Company is required to install or construct Facilities at the transferred-to LRS-3 Receipt Point to provide the Service requested, the installation or construction of such Facilities is in accordance with Article 5.0.

10.0 TITLE TRANSFERS

10.1 A Customer entitled to receive Service under Rate Schedule LRS-3 shall not be entitled to transfer or accept a transfer of Customers' inventory to or from any other Customer Account in respect of such Service under Rate Schedule LRS-3.

11.0 ASSIGNMENTS

11.1 Service is assignable only during the Secondary LRS-3 Term and any assignment shall be subject to Company's prior written consent, which consent will not be unreasonably withheld. The withholding of consent by Company to a proposed assignment shall be deemed to be reasonable if Company determines in it's sole discretion that assignee and assignor have not agreed to be bound by the obligations and provisions of Section 8 of the Memorandum of Understanding dated February 8, 2002 between Petro-Canada and Company (the "MOU"). Petro-Canada shall not be liable to Company if assignee fails to comply with the obligations and provisions of Section 8 of the MOU.

12.0 APPLICATION FOR SERVICE

12.1 Applications for Service under Rate Schedule LRS-3 shall be in such form as Company may prescribe from time to time.

13.0 GENERAL TERMS AND CONDITIONS

13.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule LRS-3 are applicable to Rate Schedule LRS-3 to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

APPENDIX 1 TO RATE SCHEDULE LRS-3

LRS-3 RECEIPT POINT	STATION NUMBER
Bowmanton	1216
Medicine Hat North #1	1017
Medicine Hat North Arco	1184
Medicine Hat South #2	1043
Medicine Hat South #4	1128
Medicine Hat Northwest	1205
Hilda West	1402

SERVICE AGREEMENT

RATE SCHEDULE LRS-3

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta ("Company")

- and -

•, a body corporate having an office in •, • ("Customer")

IN CONSIDERATION of the premises and the covenants and agreements herein contained, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule LRS-3 in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule LRS-3.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to Rate Schedule LRS-3 including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point in respect of which Customer has the right to receive Service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating volumes of gas received by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas volume actually received or the aggregate gas volume actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule LRS-3, this Service

Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix “F” of the Tariff shall be given via Company’s electronic bulletin board

("EBB"). Company shall not accept any such Notice for those matters listed in Appendix "F" via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule LRS-3, the General Terms and Conditions and Schedule of Service under Rate Schedule LRS-3 are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of , • •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE LRS-3

CUSTOMER: •

Schedule of Service Number	Receipt Point Number and Name	Legal Description	Maximum Receipt Pressure kPa	Service Termination Date	LRS-3 Contract Demand $10^3m^3/d$	Additional Conditions
•	• •	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE IT-D

INTERRUPTIBLE - DELIVERY

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule IT-D shall mean the delivery of gas to Customer at Customer's Export Delivery Points (the "Service") which includes transportation of gas that Company determines necessary to provide services under the Tariff.

2.2 The Service is available to any Customer that has executed a Service Agreement and Schedule of Service under Rate Schedule IT-D provided that capacity exists in the Facilities that is not required by any Customer entitled to receive service under Rate Schedule FT-D, Rate Schedule LRS-2, Rate Schedule STFT, Rate Schedule FT-A, Rate Schedule FT-X, Rate Schedule FT-P, Rate Schedule IT-S and Rate Schedule IT-D. Company shall not be required to construct or install Facilities for any Service under Rate Schedule IT-D. A standard form Service Agreement for Service under this Rate Schedule IT-D is attached.

3.0 PRICING

3.1 The rate used in calculating Customer's monthly charge for Service under Rate Schedule IT-D at an Export Delivery Point is the IT-D Rate at such Export Delivery Point.

4.0 CHARGE FOR SERVICE

4.1 Aggregate of Customer's Monthly Charge

The aggregate of Customer’s monthly charges for a Billing Month for Service under Rate Schedule IT-D shall be equal to the sum of the monthly charges calculated for each of Customer’s Export Delivery Points under Rate Schedule IT-D determined as follows:

MC = A x B

Where:

“MC” = the monthly charge applicable to such Export Delivery Point;

“A” = the IT-D Rate at such Export Delivery Point; and

“B” = the sum of the quantity of gas delivered by Company to such Customer at such Export Delivery Point under Rate Schedule IT-D in the month preceding such Billing Month.

4.2 Aggregate of Customer’s Surcharges

The aggregate of Customer’s Surcharges for a Billing Month shall be equal to the sum of all Surcharges set forth in the Table of Rates, Tolls and Charges applicable to each of Customer’s Export Delivery Points under Rate Schedule IT-D.

4.3 Aggregate Charge For Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 4.1 and 4.2.

4.4 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have

been nominated, the aggregate quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D;

(iv) fourthly to service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to Service to Customer under Rate Schedule IT-D.

5.0 TERM OF SERVICE

5.1 Term of Service at an Export Delivery Point

The term for any Schedule of Service for Service under Rate Schedule IT-D at each Export Delivery Point shall be the term requested by Customer, provided that the term is a minimum of one (1) month and terminates on the last day of a Gas Year.

5.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service under Rate Schedule IT-D.

6.0 TITLE TRANSFERS

6.1 A Customer entitled to receive Service under Rate Schedule IT-D may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

7.0 RENEWAL OF SERVICE

7.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule IT-D if Customer gives notice to Company of such renewal at least one (1) month prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

7.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 7.1 shall be irrevocable one (1) month prior to the Service Termination Date.

Any renewal of Service is subject to the Financial Assurances provisions in Article 10 of the General Terms and Conditions.

7.3 Renewal Term

The renewal term shall consist of increments of whole years and shall not be less than one (1) year.

8.0 APPLICATION FOR SERVICE

8.1 Applications for Service under this Rate Schedule IT-D shall be in such form as Company may prescribe from time to time.

9.0 GENERAL TERMS AND CONDITIONS

9.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule IT-D are applicable to Rate Schedule IT-D to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

SERVICE AGREEMENT

RATE SCHEDULE IT-D

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta ("Company")

- and -

•, a body corporate having an office in •, • ("Customer")

IN CONSIDERATION of the premises and the covenants and agreements in this Service Agreement, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule IT-D in accordance with the following procedure:

(a) subject to the provisions of this paragraph 3, upon execution and delivery of this Service Agreement Customer shall be entitled to Service at any Export Delivery Point described in the Schedule of Service respecting Rate Schedule IT-D, provided however that Customer may not with respect to any Service at any Export Delivery Point described in such Schedule of Service request Company to deliver a quantity of gas in excess of the capacity of the facilities (as determined by Company) downstream of such Export Delivery Point;

(b) Customer shall by written notice to Company in form and substance satisfactory to Company designate Export Delivery Points, referred to in subparagraph 3(a), with respect to which Customer desires Service pursuant to Rate Schedule IT-D;

(c) from and after the time of receipt by Company of Customer's written notice referred to in subparagraph 3(b) determined in Company's sole judgment, Customer shall be entitled to receive Service pursuant to Rate Schedule IT-D with respect to the Export Delivery Points designated as provided for in subparagraph 3(b) in priority to all Customers requesting such Service after the time, but subject to all Customers requesting such Service prior to the time, of Company's receipt of such written notice; and

(d) Customer shall at Company’s request from time to time provide written confirmation of the Export Delivery Points designated by Customer pursuant to subparagraph 3(b).

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule IT-D.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule IT-D including, without limiting the generality of the foregoing, an assurance that all necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company’s request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule IT-D, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix “F” of the Tariff shall be given via Company’s electronic bulletin board (“EBB”). Company shall not accept any such Notice for those matters listed in Appendix “F” via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

7. The terms and conditions of Rate Schedule IT-D, the General Terms and Conditions and Schedule of Service under Rate Schedule IT-D are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE IT-D

CUSTOMER: •

Schedule of Service Number	Export Delivery Point Number and Name	Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Additional Conditions
•	• •	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

RATE SCHEDULE IT-S

INTERRUPTIBLE - ACCESS TO STORAGE

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule IT-S shall mean:

(i) the delivery of gas by Company for Customer at Storage Delivery Points; and

(ii) the receipt of gas by Company for Customer at Storage Receipt Points.

Subparagraphs (i) and (ii) are collectively referred to as the "Service" which includes transportation of gas that Company determines necessary to provide services under the Tariff.

2.2 The Service is available to any Customer that has executed a Service Agreement and Schedule of Service under Rate Schedule IT-S and a valid Service Agreement under Rate Schedule FCS is executed by any Customer at the Storage Delivery Point provided that:

(i) with respect to subparagraph 2.1(i), capacity exists in the Facilities that is not required by Company to provide service under Rate Schedule FT-A, Rate Schedule FT-D, Rate Schedule FT-X, Rate Schedule LRS-2, Rate Schedule STFT, Rate Schedule FT-P, Rate Schedule IT-D and Rate Schedule IT-S; and

(ii) with respect to subparagraph 2.1(ii), capacity exists in the Facilities that is not required by Company to provide service under Rate Schedule FT-R, Rate

Schedule FT-RN, Rate Schedule FT-P, Rate Schedule FT-X, Rate Schedule LRS, Rate Schedule LRS-2, Rate Schedule LRS-3, Rate Schedule IT-R and Rate Schedule IT-S.

A standard form Service Agreement for Service under Rate Schedule IT-S is attached.

2.3 Company shall not be required to construct or install Facilities for any Service under Rate Schedule IT-S. If Company determines that new Facilities are required that are directly attributable to Customer's request for Service, Company shall not be required to provide such requested Service unless a valid Service Agreement under Rate Schedule FCS exists in respect of such new Facilities.

3.0 CHARGE FOR SERVICE

3.1 Aggregate of Customer's Monthly Charge

(i) Customer undertakes to cause the operator of the gas storage facility connected to the Storage Receipt Point and the Storage Delivery Point to provide any information necessary to satisfy Company that the volume of gas received by Company at the Storage Receipt Point connected to a Storage Facility was previously delivered by Company at the Storage Delivery Point for such Storage Facility. If Company is satisfied that the volume of gas received by Company at the Storage Receipt Point connected to a Storage Facility was previously delivered by Company at the Storage Delivery Point for such Storage Facility, Company shall not charge Customer for Service under this Rate Schedule IT-S.

(ii) If the operator of a gas storage facility fails to provide information to Company's satisfaction that all or a portion of the volume of gas received by Company at the Storage Receipt Point connected to a Storage Facility was previously delivered by Company at the Storage Delivery Point for such Storage Facility, then Company shall charge for such volumes in accordance with the allocations determined by Company in paragraph 4.1.

(iii) If the operator of the gas storage facility fails to provide information to Company's satisfaction that all or a portion of the volume of gas delivered by Company at the Storage Delivery Point connected to a Storage Facility is for the sole purpose of storage and ultimate receipt by Company from such Storage Facility at the Storage Receipt Point, then Company shall charge for such volumes in accordance with the allocations determined by Company in paragraph 4.2.

3.2 Aggregate of Customer's Surcharges

The aggregate of Customer's Surcharges for a Billing Month shall be equal to the sum of all Surcharges set forth in the Table of Rates, Tolls and Charges applicable to each of Customer's Schedules of Service under Rate Schedule IT-S.

3.3 Aggregate Charge for Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 3.1 and 3.2.

4.0 ALLOCATION OF GAS RECEIVED AND DELIVERED

4.1 Allocation of Gas Received

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of this Tariff, and without regard to how gas may have been nominated, the aggregate volume of gas received at a Storage Receipt Point for Customer, shall be allocated as follows:

(i) If paragraph 3.1(i) applies, then the volume of gas received shall be allocated only to Service to Customer under Rate Schedule IT-S; or

(ii) If paragraph 3.1(ii) applies, then the volume of gas received shall be allocated:

(a) first to service to Customer under Rate Schedules LRS and LRS-3 to a maximum of such Customer's LRS Contract Demand for such Receipt Point under such Rate Schedule LRS and to a maximum of such Customer's LRS-3 Contract Demand for such Receipt Point under such Rate Schedule LRS-3;

(b) secondly to service to Customer under Rate Schedule FT-R to a maximum of such Customer's Receipt Contract Demand for such Storage Receipt Point under such Rate Schedule FT-R;

(c) thirdly to service to Customer under Rate Schedule FT-RN to a maximum of such Customer's Receipt Contract Demand for such Storage Receipt Point under such Rate Schedule FT-RN;

(d) fourth to service to Customer under Rate Schedule IT-R at such Storage Receipt Point. If Customer is not entitled to service under Rate Schedule IT-R at such Storage Receipt Point, then Customer shall pay the IT-R Rate at such Storage Receipt Point in respect of such volume of gas allocated to it hereunder.

4.2 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of this Tariff, and without regard to how gas may have been nominated, the aggregate quantity of gas delivered at a Storage Delivery Point for Customer, shall be allocated as follows:

(i) If paragraph 3.1(i) applies, then the quantity of gas delivered shall be allocated only to Service to Customer under Rate Schedule IT-S; or

(ii) If paragraph 3.1(iii) applies, then the quantity of gas delivered shall be allocated:

(a) first to service to Customer under Rate Schedule FT-A at such Storage Delivery Point, if Company is satisfied that the quantity of gas delivered by Company at such Storage Delivery Point is not to be removed from Alberta. If Customer is not entitled to service under Rate Schedule FT-A at such Storage Delivery Point, then Customer shall pay the FT-A Rate in respect of such quantity of gas allocated to it hereunder;

(b) secondly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Storage Delivery Point under such Rate Schedule FT-D; and

(c) thirdly, under all other circumstances other than the ones set out in paragraphs 4.2(ii)(a) and 4.2(ii)(b), to service to Customer under Rate Schedule IT-D at such Storage Delivery Point. If Customer is not entitled to service under Rate Schedule IT-D at such Storage Delivery Point, regardless of whether of not such Storage Delivery Point is an Export Delivery Point, then Customer shall pay the IT-D Rate in respect of such quantity of gas allocated to it hereunder.

5.0 STORAGE INFORMATION

5.1 Customer undertakes to cause the operator of every gas storage facility connected to the Storage Receipt Point and the Storage Delivery Point to provide to Company, when requested by the Company, the following information:

(i) the cumulative total of the volume of gas delivered to the Storage Delivery Point for Customer by Company; and

(ii) the cumulative total of the volume of gas received at the Storage Receipt Point by Company for Customer.

5.2 If the operator of a gas storage facility fails to provide Company with the information requested with respect to any month within the time provided by Company for a response to Company's request:

(i) the gas received at the Storage Receipt Point for Customer for such month shall be deemed to have been received for Customer at the Storage Receipt Point under Rate Schedule IT-R and Customer shall pay the IT-R Rate applicable to such Storage Receipt Point in respect of such volume; and

(ii) the gas delivered at the Storage Delivery Point for Customer for such month shall be deemed to have been delivered by Customer at the Storage Delivery Point under Rate Schedule IT-D and Customer shall pay the IT-D Rate in respect to such quantity regardless of whether or not such Storage Delivery Point is an Export Delivery Point.

6.0 TERM OF SERVICE

6.1 Term of Service at a Storage Receipt Point and Delivery Point

The term for any Schedule of Service for Service under Rate Schedule IT-S at each Storage Receipt Point and at each Storage Delivery Point shall be the term requested by Customer, provided that the term is a minimum of one (1) month and terminates on the last day of a Gas Year.

6.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service under Rate Schedule IT-S.

7.0 TITLE TRANSFERS

7.1 A Customer entitled to receive Service under Rate Schedule IT-S may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

8.0 RENEWAL OF SERVICE

8.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule IT-S if Customer gives notice to Company of such renewal at least one (1) month prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

8.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 8.1 shall be irrevocable one (1) month prior to the Service Termination Date.

Any renewal of Service is subject to the Financial Assurances provisions in Article 10 of the General Terms and Conditions.

8.3 Renewal Term

The renewal term shall consist of increments of whole years and shall not be less than one (1) year.

9.0 APPLICATION FOR SERVICE

9.1 Applications for Service under this Rate Schedule IT-S shall be in such form as Company may prescribe from time to time.

10.0 GENERAL TERMS AND CONDITIONS

10.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule IT-S are applicable to Rate Schedule IT-S to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

SERVICE AGREEMENT

RATE SCHEDULE IT-S

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta (“Company”)

- and -

•, a body corporate having an office in •, • (“Customer”)

IN CONSIDERATION of the premises and the covenants and agreements in this Service Agreement, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule IT-S in accordance with the following procedure:

(a) subject to the provisions of this paragraph 3, upon execution and delivery of this Service Agreement Customer shall be entitled to Service from any Storage Receipt Point and Storage Delivery Point described in the Schedule of Service respecting Rate Schedule IT-S, provided however that Customer may not with respect to any Service at any Storage Receipt Point and Storage Delivery Point described in such Schedule of Service request Company to receive a volume of gas in excess of the capacity of the facilities (as determined by Company) upstream of such Storage Receipt Point or in excess of the capacity of the Facilities (as determined by Company) downstream of such Storage Delivery Point;

(b) Customer shall by written notice to Company in form and substance satisfactory to Company designate Storage Receipt Points and Storage Delivery Points, referred to in subparagraph 3(a), with respect to which Customer desires Service pursuant to Rate Schedule IT-S;

(c) from and after the time of receipt by Company of Customer’s written notice referred to in subparagraph 3(b) determined in Company's sole judgment, Customer shall be entitled to receive Service pursuant to Rate Schedule IT-S with respect to the Storage Receipt Points and Storage Delivery Points designated as provided for in subparagraph 3(b) in priority to all Customers requesting such Service after the time, but subject to all Customers requesting such Service prior to the time, of Company’s receipt of such written notice; and

(d) Customer shall at Company’s request from time to time provide written confirmation of the Storage Receipt Points and Storage Delivery Points designated by Customer pursuant to subparagraph 3(b).

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule IT-S.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule IT-S including, without limiting the generality of the foregoing, an assurance that all necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such

Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point or downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating quantities of gas received or delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule IT-S, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix “F” of the Tariff shall be given via Company’s electronic bulletin board (“EBB”). Company shall not accept any such Notice for those matters listed in Appendix “F” via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

7. The terms and conditions of Rate Schedule IT-S, the General Terms and Conditions and Schedule of Service under Rate Schedule IT-S are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE IT-S

CUSTOMER: •

Schedule of Service Number	Storage Receipt and Delivery Point Number and Name	Storage Receipt and Delivery Point Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Additional Conditions
•	• •	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

GENERAL TERMS AND CONDITIONS

GENERAL TERMS AND CONDITIONS

1.0 DEFINITIONS

In this Tariff:

1.1 “Act” shall mean the *Gas Utilities Act*, R.S.A. 1980, c. G-4, as amended.

1.2 “Alberta Delivery Point” shall mean the point in Alberta where gas that is not to be removed from Alberta is delivered to Customer by Company under a Schedule of Service.

1.3 “Annual Plan” shall mean a document submitted annually to the Board by Company outlining the Company’s planned Facility additions and major modifications.

1.4 “Banking Day” shall mean any day that the Royal Bank of Canada, Main Branch, Calgary, Canada, or other financial institutions agreed to by Company, conducts business.

1.5 “Billing Commencement Date” shall mean the earlier of:

(a) the Ready for Service Date; and

(b) the date Company commences to provide Service to Customer pursuant to a Service Agreement or Schedule of Service.

1.6 Billing Month” shall mean that month which immediately precedes the month in which Company is required to send a bill for Service.

1.7 “Block Period” shall have the meaning attributed to it in paragraph 3.2 of Rate Schedule STFT.

1.8 “Board” shall mean the Alberta Energy and Utilities Board.

1.9 "CO_2 Volume" shall mean the portion of the total excess volume of carbon dioxide allocated by a CSO to a Customer at a particular Receipt Point for any month under a Schedule of Service for Service under Rate Schedule CO_2. The total excess volume of carbon dioxide at a Receipt Point for any month shall be determined by Company as follows:

Total Excess CO_2 Volume = A x (B - C)

Where:

"A" = the total volume of gas received by Company at such Receipt Point;

"B" = the percentage of carbon dioxide by volume of gas received as determined by Company at such Receipt Point; and

"C" = two (2) percent.

If "B" is less than or equal to "C", the Total Excess CO_2 Volume shall be zero.

1.10 "CO_2 Rate" shall mean the CO_2 Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule CO_2.

1.11 "Common Stream Operator" or "CSO" shall mean the person who, with respect to a Receipt Point:

(i) provides Company with the estimates of Flow at the Receipt Point;

(ii) provides Company with the allocation of the estimated Flow and Total Quantity for the Receipt Point to each Customer receiving Service at the Receipt Point; and

(iii) accepts Nominations made by Company on behalf of Customers and confirms the availability of gas to meet Customer's Nominations.

1.12 "Company" shall mean NOVA Gas Transmission Ltd. and any successor to it.

1.13 "Company's Gas Use Price" shall mean the monthly weighted average of the "AECO/NGX Intra-Alberta Same Day Index Values" for every day of the month recorded by the Natural Gas Exchange Inc. (or its successor) as published on its website (or any replacement thereof) for the month preceding the Billing Month multiplied by the average heating value of all physical gas received by Company for the month preceding the Billing Month.

1.14 "Connecting Pipeline Operator" or "CPO" shall mean the person who, with respect to a Delivery Point, places Nominations with Company on behalf of Customers.

1.15 "Criteria for Determining Primary Term" shall mean the procedure for determining the Primary Term, as set out in Appendix "E" of the Tariff.

1.16 "Cubic Metre of Gas" shall mean that quantity of gas which, at a temperature of fifteen (15) degrees Celsius and at an absolute pressure of one hundred one and three hundred twenty-five thousandths (101.325) kiloPascals occupies a volume of one cubic metre.

1.17 "Customer" shall mean any Person named as a Customer in a Service Agreement or Schedule of Service.

1.18 "Customer Account" shall mean an account established by Company for Customer to record Customer's transactions related to Service under one or more Rate Schedules.

1.19 "Customer Bid" shall have the meaning attributed to it in paragraph 4.2 of Rate Schedule STFT.

1.20 "Customer's Inventory" shall mean, for each Customer Account at a given time on a day, an estimated energy amount determined by Company as follows:

$$CI = (A + B) - (C + D) - E \pm F$$

Where:

"CI" = the Customer's Inventory;

“A” = the gas received by Company from Customer at all of Customer’s Receipt Points;

“B” = the gas received by Customer from another Customer through title transfers;

“C” = the gas delivered by Company to Customer at all of Customer’s Delivery Points;

“D” = the gas delivered by Customer to another Customer through title transfers;

“E” = the gas allocated to Customer for Gas Used, Gas Lost, and Measurement Variance; and

“F” = the daily recovery of Customer’s Inventory imbalance as a result of:

(i) any differences in measurement or allocations between the daily estimated gas received by Company from Customer at all of Customer’s Receipt Points and the month end actual quantity of gas received by Company from Customer at such Receipt Points;

(ii) any differences in measurement or allocations between the daily estimated quantity of gas delivered by Company to Customer at all of Customer’s Delivery Points and the month end actual gas delivered by Company to Customer at such Delivery Points;

(iii) any corrections due to measurement or allocations of gas for any prior months; and

(iv) Company's administration of Customer's Inventory at month end pursuant to paragraphs 8.2 and 8.3 in Appendix "D" of the Tariff.

1.21 "Day" shall mean a period of twenty-four (24) consecutive hours, beginning and ending at eight hours (08:00) Mountain Standard Time.

1.22 "Delivery Demand Charge" shall have the meaning attributed to it in subparagraph 4.2.2 (ii) of Rate Schedule LRS.

1.23 "Delivery Point" shall mean the point where gas may be delivered to Customer by Company under a Schedule of Service and shall include but not be limited to Export Delivery Point, Alberta Delivery Point, Extraction Delivery Point and Storage Delivery Point.

1.24 "Effective LRS Rate" shall mean the Effective LRS Rate set forth in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule LRS.

1.25 "Eligible LRS Contract Demand" shall have the meaning attributed to it in subparagraph 4.2.1 of Rate Schedule LRS.

1.26 "Eligible LRS-3 Contract Demand" shall have the meaning attributed to it in subparagraph 4.2.1 of Rate Schedule LRS-3.

1.27 "Eligible LRS-2 Volume" shall have the meaning attributed to it in subparagraph 4.3.2 of Rate Schedule LRS-2.

1.28 "Eligible Points to Point Volume" shall mean for each Schedule of Service under Rate Schedule FT-P, the lesser of:

(i) the sum of each Points to Point Contract Demand in effect for all or a portion of the month preceding the Billing Month multiplied by the number of days that the Customer was entitled to such Points to Point Contract Demand under such Schedule of Service in such month;

(ii) the actual volume of gas received by Company from Customer at the Receipt Points under such Schedule of Service; or

(iii) the actual volume of gas delivered by Company to Customer at the Alberta Delivery Point under such Schedule of Service.

1.29 "Emergency Response Compensation Event" or "ERC Event" shall have the meaning attributed to it in Appendix "G" of the Tariff.

1.30 "Export Delivery Contract Demand" shall mean the maximum quantity of gas, expressed in GJ or as converted to GJ pursuant to paragraph 15.12, Company may be required to deliver to Customer at the Export Delivery Point on any Day, as set forth in the Schedule of Service.

1.31 "Export Delivery Point" shall mean any of the following points where gas is delivered to a Customer for removal from Alberta under a Schedule of Service:

Alberta-British Columbia Border
Alberta-Montana Border
Boundary Lake Border
Cold Lake Border
Demmitt #2 Interconnect
Empress Border
Gordondale Border
McNeill Border
Unity Border

1.32 "Extraction Delivery Point" shall mean the point in Alberta where gas may be delivered to the Extraction Plant by Company for Customer under a Schedule of Service.

1.33 "Extraction Plant" shall mean a facility connected to the Facilities where Gas liquids are extracted.

1.34 "Extraction Receipt Point" shall mean the point in Alberta where gas may be received from the Extraction Plant by Company for Customer under a Schedule of Service.

1.35 "Facilities" shall mean Company's pipelines and other facilities or any part or parts thereof for the receiving, gathering, treating, transporting, storing, distributing, exchanging, handling or delivering of gas.

1.36 "Final ERC Adjustment" shall have the meaning attributed to it in Appendix "G" of the Tariff.

1.37 "Financial Assurance" shall have the meaning attributed to it in paragraph 10.1.

1.38 "Flow" shall mean, with respect to a Receipt Point, the rate in $10^3m^3/d$ or GJ/d, as the case may be, that gas is being delivered into Company's Facilities through such Receipt Point at any point in time and means with respect to a Delivery Point, the rate in $10^3m^3/d$ or GJ/d, as the case may be, that gas is being delivered off Company's Facilities through such Delivery Point at any point in time.

1.39 "FT-A Rate" shall mean the FT-A Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-A.

1.40 "FT-D Demand Rate" shall mean the FT-D Demand Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-D.

1.41 "FT-DW Demand Rate" shall mean the FT-DW Demand Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-DW.

1.42 "FT-P Customer Account" shall mean an account established by Company for Customer to record Customer's transactions related to Service under Rate Schedule FT-P.

1.43 "FT-P Demand Rate" shall mean the FT-P Demand Rate for the distance between the particular Receipt Points and the particular Alberta Delivery Point in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-P.

1.44 "FT-R Demand Rate" shall mean the FT-R Demand Rate for a particular Receipt Point in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-R.

1.45 "FT-RN Demand Rate" shall mean the FT-RN Demand Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-RN for a particular Receipt Point.

1.46 "Gas" or "gas" shall mean all natural gas both before and after it has been subjected to any treatment or process by absorption, purification, scrubbing or otherwise, and includes all fluid hydrocarbons other than hydrocarbons that can be recovered from a pool in liquid form by ordinary production methods.

1.47 "GIA" shall mean the Electricity and Gas Inspection Act, R.S.C. 1985, c. E-4, as amended, and all Regulations issued pursuant to it.

1.48 "Gas Lost" shall mean that quantity of gas determined by Company to be the aggregate of:

(i) the total quantity of gas lost as a result of a Facilities rupture or leak; and

(ii) any Customer's Inventory that Company reasonably determines to be unrecoverable.

1.49 "Gas Used" shall mean that quantity of gas determined by Company to be the total quantity of gas used by Company in the operation, maintenance and construction of the Facilities.

1.50 "Gas Year" shall mean a period of time beginning at eight hours (08:00) Mountain Standard Time on the first day of November in any year and ending at eight hours (08:00) Mountain Standard Time on the first day of November of the next year.

1.51 "GJ" shall mean gigajoule, or one billion joules.

1.52 "Gross Heating Value" shall mean the total MJ obtained by complete combustion of one cubic metre of gas with air, the gas to be free of all water vapour and the gas, air and products of combustion to be at standard conditions of fifteen (15) degrees Celsius and one hundred one and three hundred twenty-five thousandths (101.325) kiloPascals (absolute) and all water vapour formed by the combustion reaction condensed to the liquid state.

1.53 "IT-D Rate" shall mean the IT-D Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule IT-D.

1.54 "IT-R Rate" shall mean the IT-R Rate for a particular Receipt Point in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule IT-R.

1.55 "J" or "joule" shall mean the base unit for energy as defined by the International System of Units (SI).

1.56 "kPa" or "kiloPascals " shall mean kiloPascals of pressure (gauge) unless otherwise specified.

1.57 "Line Pack Gas" shall mean at any point in time that quantity of gas determined by Company to be the total quantity of gas contained in the Facilities.

1.58 "LRS Billing Adjustment" shall have the meaning attributed to it in subparagraph 4.2.4 of Rate Schedule LRS.

1.59 "LRS Charge" shall have the meaning attributed to it in subparagraph 4.2.3 of Rate Schedule LRS.

1.60 "LRS Contract Demand" shall mean the maximum daily volume of gas Company may be required to receive from Customer and deliver at the Empress or McNeill Border Export Delivery Point under Rate Schedule LRS.

1.61 "LRS Receipt Point Obligation" shall mean the period determined in subparagraph 6.2 or 6.3 of Rate Schedule LRS as the case may be.

1.62 "LSR-3 Contract Demand" shall mean the maximum daily volume of gas Company may be required to receive from Customer and deliver at the Empress Border Export Delivery Point under a Schedule of Service for Service under Rate Schedule LRS-3.

1.63 "LRS-3 Demand Rate" shall mean the LRS-3 Demand Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule LRS-3.

1.64 "Maximum Carbon Dioxide Volume" shall mean the maximum total excess CO_2 Volume as determined by Company that the Company may be required to accept at a particular Receipt Point on any day, as set forth in a Schedule of Service under Rate Schedule CO_2.

1.65 "Maximum Delivery Pressure" shall mean relative to a Delivery Point the maximum pressure at which Company may deliver gas to Customer, as set forth in a Schedule of Service.

1.66 "Maximum Receipt Pressure" shall mean relative to a Receipt Point the maximum pressure at which Company may require Customer to deliver gas, as set forth in Schedule of Service.

1.67 "Measurement Variance" shall mean, for any period, after taking into account any adjustment made in accordance with the provisions of paragraph 2.6 of these General Terms and Conditions, the energy equivalent of the amount determined as follows:

MV = (A + B + C) - (D + E)

Where:

"MV" = the Measurement Variance;

"A" = the energy equivalent of gas determined by Company to have been delivered to all Customers during the period;

"B" = the energy equivalent of the aggregate of the Gas Lost and Gas Used during the period;

"C" = the energy equivalent of Line Pack Gas at the end of the period;

"D" = the energy equivalent of gas determined by Company to have been received from all Customers during the period; and

"E" = the energy equivalent of Line Pack Gas at the beginning of the period.

1.68 "MJ" shall mean megajoule, or one million joules.

1.69 "Month" or "month" shall mean a period of time beginning at eight hours (8:00) Mountain Standard Time on the first day of a calendar month and ending at eight hours (08:00) Mountain Standard Time on the first day of the next calendar month.

1.70 "Nomination" shall mean, with respect to a Receipt Point or a Delivery Point, a request for Flow made on behalf of a Customer.

1.71 "Non-Responding Plant" shall have the meaning attributed to it in Appendix "G" of the Tariff.

1.72 "Officer's Certificate" shall have the meaning attributed to it in subparagraph 4.2.1 of Rate Schedule LRS for Service under Rate Schedule LRS and subparagraph 4.3.1 of Rate Schedule LRS-2 for Service under Rate Schedule LRS-2.

1.73 "Over-Run Gas" shall mean, in respect of a Customer in a month, the aggregate quantity of gas for which an amount for over-run gas is payable by Customer in the Billing Month.

1.74 "OS Charge" shall mean an OS Charge in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule OS.

1.75 "Person" shall mean and include Company, a Customer, a corporation, a company, a partnership, an association, a joint venture, a trust, an unincorporated organization, a government, or department of a government or a section, branch, or division of a department of a government.

1.76 "Points to Point Contract Demand" shall mean the maximum volume of gas Company may be required to receive from Customer at particular Receipt Points and deliver to Customer at a particular Alberta Delivery Point on any day under a Schedule of Service under Rate Schedule FT-P.

1.77 "Price Point" shall mean Price Point "A", Price Point "B", or Price Point "C", each as defined in paragraph 3.2 of Rate Schedule FT-R and Rate Schedule FT-P.

1.78 "Primary Term" shall mean for the purposes of any Service provided under any Schedule of Service the term calculated in accordance with the Criteria for Determining Primary Term in Appendix "E" of the Tariff.

1.79 "Prime Rate" shall mean the rate of interest, expressed as an annual rate of interest, announced from time to time by the Royal Bank of Canada, Main Branch, Calgary, Alberta as the reference rate then in effect for determining interest rates on Canadian dollar commercial loans in Canada.

1.80 "Project Area" shall mean each of:

(i) the Peace River Project Area;

(ii) the North and East Project Area; and

(iii) the Mainline Project Area,

as described in Company's current Annual Plan. The Project Areas may be amended from time to time by Company in consultation with the Facility Liaison Committee (or any replacement of it), provided Company has given six (6) months notice of such amendment to its Customers.

1.81 "PT Gas Rate" shall mean the PT Gas Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule PT, based on the incremental gas requirements associated with the Facilities required to provide such Service.

1.82 "PT Rate" shall mean the PT Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule PT, based on the incremental operating costs associated with providing such Service plus ten percent.

1.83 "Quantity Multiplier" shall have the meaning attributed to it in subparagraph 6.1 (a) of Rate Schedule STFT.

1.84 "Rate Schedule" shall mean any of the schedules identified as a "Rate Schedule" included in the Tariff.

1.85 "Ready for Service Date" shall mean the Day designated as such by Company by written notice to Customer stating that Company has Facilities which are ready for and are capable of rendering the Service applied for by Customer.

1.86 "Receipt Contract Demand" shall mean the maximum volume of gas Company may be required to receive from Customer at a Receipt Point on any Day, under a Schedule of Service.

1.87 "Receipt Demand Charge" shall have the meaning attributed to it in subparagraph 4.2.2 (i) of Rate Schedule LRS.

1.88 "Receipt Point" shall mean the point in Alberta at which gas may be received from Customer by Company under a Service Agreement or Schedule of Service.

1.89 "Responding Plant" shall have the meaning attributed to it in Appendix "G" of the Tariff.

1.90 "STFT Bid Price" shall have the meaning attributed to it in article 5.0 of Rate Schedule STFT.

1.91 "STFT Capacity" shall have the meaning attributed to it in paragraph 3.1 of Rate Schedule STFT.

1.92 "Schedule of Service" shall mean the attachment(s) to a Service Agreement for Service under any Rate Schedule designated as "Schedule of Service" and any amendments thereto.

1.93 "Secondary Term" shall mean for the purposes of Service provided under any Schedule of Service any portion of the term of the Schedule of Service that is not Primary Term.

1.94 "Service" shall have the meaning attributed to it in article 2.0 of the applicable Rate Schedule.

1.95 "Service Agreement" shall mean an agreement between Company and Customer respecting Service to be provided under any Rate Schedule.

1.96 "Service Termination Date" shall mean the last Day in a month upon which Service shall terminate, as set forth in a Schedule of Service and subject to any renewal thereof.

1.97 "Storage Delivery Point" shall mean the point in Alberta where gas may be delivered to the Storage Facility by Company for Customer for ultimate receipt from such Storage Facility at the Storage Receipt Point under a Schedule of Service.

1.98 "Storage Facility" shall mean any commercial facility where gas is stored, that is connected to the Facilities and is available to all Customers.

1.99 "Storage Receipt Point" shall mean the point in Alberta where gas may be received from the Storage Facility by Company for Customer that was previously delivered to such Storage Facility at the Storage Delivery Point under a Schedule of Service.

1.100 "Surcharge" shall mean a Surcharge set forth in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under a Rate Schedule.

1.101 "Table of Rates, Tolls and Charges" shall mean the Table of Rates, Tolls and Charges setting forth rates, tolls and charges that have been fixed by Company or the Board to be imposed, observed and followed by Company.

1.102 "Tariff" shall mean this Gas Transportation Tariff, including the Table of Rates, Tolls and Charges, the Rate Schedules, the Service Agreements, Schedules of Service, these General Terms and Conditions and the Appendices.

1.103 "Tier" shall mean the Tier 1, Tier 2 or Tier 3 CO_2 Rate as set forth in the Table of Rates, Tolls and Charges.

1.104 "TJ" shall mean terajoule, or one trillion joules.

1.105 "Thousand Cubic Metres" or "10^3m^3" shall mean one thousand (1000) Cubic Metres of Gas.

1.106 "Winter Season" shall mean the period commencing on November 1 of any year and ending on the next succeeding March 31.

2.0 MEASURING EQUIPMENT

2.1 Installation

Company, at its option, may furnish, install, maintain and operate all measuring equipment located at each Receipt Point, Delivery Point or other point where gas is measured.

2.2 Compliance with Standards

Company may use such measuring equipment as it deems appropriate provided that all measuring equipment shall comply with all applicable requirements under the GIA.

2.3 Check Measuring Equipment

Customer may install and operate check measuring equipment provided that such equipment does not interfere with the operation of the Facilities.

2.4 Pulsation Dampening

Customer shall provide or cause to be provided such pulsation dampening equipment as may be necessary to ensure that any facilities upstream of a Receipt Point do not interfere with the operation of the Facilities.

2.5 Verification

The accuracy of Company's measuring equipment shall be tested and verified by Company at such intervals as may be appropriate for such equipment. Reasonable notice of the time and nature of each test shall be given to Customer to permit Customer to arrange for a representative to observe the test and any adjustments resulting from such test. If, after notice, Customer fails to have a representative present, the results of the test shall nevertheless be considered accurate.

2.6 Correction

If at any time any of the measuring equipment is found to be out of service or registering inaccurately with the result that a significant measurement error has occurred, such equipment shall be adjusted as soon as practicable to read as accurately as possible and the readings of such equipment shall be adjusted to correct for such significant error for a period definitely known or agreed upon, or if not known or agreed upon, one-half (1/2) of the elapsed time since the last test. The measurement during the appropriate period shall be determined by Company on the basis of the best data available using the most appropriate of the following methods:

(a) by using the data recorded by any check measuring equipment if installed and accurately registering;

(b) by making the appropriate correction if the deviation from the accurate reading is ascertainable by calibration test or mathematical calculation;

(c) by estimating based on producer measurements; or

(d) by estimating based on deliveries under similar conditions during a period when the equipment was measuring accurately.

2.7 Expense of Additional Tests

If Customer requests a test in addition to the tests provided for by paragraph 2.5 and if upon testing the deviation from the accurate reading is found to be less than two (2) percent, Customer shall bear the expense of the additional test.

2.8 Inspection of Equipment and Records

Company and Customer shall have the right to inspect measuring equipment installed or furnished by the other, and the charts and other measurement or test data of the other at all times during normal business hours upon reasonable notice, but the reading, calibration and adjustment of such equipment and the changing of the charts shall be done only by the Person installing and furnishing same.

2.9 Quality Equipment and Tests

(a) Company may furnish, install, maintain and operate such equipment as it considers necessary to ensure that gas received by Company conforms to the quality requirements set forth in the Tariff.

(b) Company may establish and utilize such reasonable methods, procedures and equipment as Company determines are necessary in order to determine whether gas received by Company conforms with the quality requirements set forth in the Tariff.

3.0 GAS QUALITY

3.1 Quality Requirements

Gas received at a Receipt Point:

(a) shall be free, at the pressure and temperature in the Facilities at the Receipt Point, from sand, dust, gums, crude oil, contaminants, impurities or other objectionable substances which will render the gas unmerchantable, cause injury, cause damage to or interfere with the operation of the Facilities;

(b) shall not have a hydrocarbon dew point in excess of minus ten (-10) degrees Celsius at operating pressures;

(c) shall not contain more than twenty-three (23) milligrams of hydrogen sulphide per one (1) cubic metre;

(d) shall not contain more than one hundred and fifteen (115) milligrams of total sulphur per one (1) cubic metre;

(e) shall not contain more than two (2) percent by volume of carbon dioxide unless a valid Service Agreement and Schedule of Service under Rate Schedule CO_2 is executed by Customer and in effect at such Receipt Point;

(f) shall not contain more than:

(i) sixty-five (65) milligrams of water vapour per one (1) cubic metre; or

(ii) forty-eight (48) milligrams of water vapour per one (1) cubic metre if a valid Service Agreement and Schedule of Service under Rate Schedule CO_2 is executed and in effect at such Receipt Point;

(g) shall not have a water dew point in excess of minus ten (-10) degrees Celsius at operating pressures greater than eight thousand two hundred seventy five (8275) kPa;

(h) shall not exceed forty-nine (49) degrees Celsius in temperature;

(i) shall be as free of oxygen as practicable and shall not in any event contain more than four-tenths of one (0.4) percent by volume of oxygen; and

(j) shall have a Gross Heating Value of not less than thirty-six (36) megaJoules per cubic metre.

3.2 Nonconforming Gas

(a) If gas received by Company fails at any time to conform with any of the quality requirements set forth in paragraph 3.1 above, then Company shall notify Customer of such failure and Company may, at Company's option, refuse to accept such gas pending the remedying of such failure to conform to quality requirements. If the failure to conform is not promptly remedied, Company may accept such gas and may take such steps as Company determines are necessary to ensure that such gas conforms with the quality requirements and Customer shall reimburse Company for any reasonable costs and expenses incurred by Company.

(b) Notwithstanding subparagraph 3.2 (a), if gas received by Company fails to conform to the quality requirements set forth in paragraph 3.1 above, Company may at its option immediately suspend the receipt of gas, provided however that any such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

(c) Notwithstanding subparagraphs 3.2 (a) and 3.2 (b), if gas received by Company fails to conform to the quality requirements set forth in subparagraph 3.1(e) above, Company shall notify Customer of such failure. If the failure to conform is not remedied by Customer within thirty (30) days, Company shall refuse to accept such gas pending the remedying of such failure, provided however that any such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

3.3 Quality Standard of Gas Delivered at Delivery Points

Gas which Company delivers at Delivery Points shall have the quality that results from gas having been transported and commingled in the Facilities.

4.0 MEASUREMENT

4.1 Method of Measurement

Company may make such measurements and calculations and use such procedures as it deems appropriate in determining volume and energy, provided that the measurements and calculations made and the procedures used comply with any applicable requirements under the GIA.

4.2 Unit of Measurement

4.2.1 The unit of volume for purposes of measurement hereunder shall be a Thousand Cubic Metres.

4.2.2 The unit of energy for purposes of measurement hereunder shall be a GJ.

4.3 Atmospheric Pressure

For the purpose of measurement atmospheric pressure shall be determined by a recognized formula applied to the nearest one hundredth (0.01) kPa absolute and deemed to be constant at the time and location of measurement.

4.4 Flowing Temperature

The temperature of flowing gas shall be determined by means of a recording thermometer or other equipment appropriate for the determination of temperature.

4.5 Determination of Gas Characteristics

The gas characteristics including, without limiting the generality of the foregoing, Gross Heating Value, relative density, nitrogen and carbon dioxide content, shall be determined by continuous recording equipment, laboratory equipment or through computer modeling.

4.6 Exchange of Measurement Information

Company and Customer shall make available to the other, as soon as practicable following written request, all measurement and test charts, measurement data and measurement information pertaining to the Service being provided to Customer.

4.7 Preservation of Measurement Records

Company and Customer shall preserve all measurement test data, measurement charts and other similar records for a minimum period of six (6) years or such longer period as may be required by record retention rules of any duly constituted regulatory body having jurisdiction.

5.0 BILLING AND PAYMENT

5.1 Billing

On or before the twentieth (20th) day of each month, Company shall render a bill to Customer for Service rendered during the Billing Month. Customer shall furnish such information to Company as Company may require for billing on or before the twentieth (20th) day of the Billing Month.

5.2 Payment

Customer shall make payment to Company in Canadian dollars of its bill on or before the last day of the month following the Billing Month.

5.3 Late Billing

If Company renders a bill after the twentieth (20th) day of a month, then the date for payment shall be that day which is ten (10) days after the day that such bill was rendered.

5.4 Interest on Unpaid Amounts

Company shall have the right to charge interest on the unpaid portion of any bill commencing from the date payment was due and continuing until the date payment is actually received, at a rate per annum equal to the Prime Rate plus one (1) percent. The principal and accrued interest to date shall be due and payable immediately upon demand.

5.5 Adjustment Where Bill Estimated

Information used for billing may be actual or estimated. If actual information necessary for billing is unavailable to Company sufficiently in advance of the twentieth (20th) day of the month to permit the use of such information in the preparation of a bill, Company shall use estimated information. In the month that actual information becomes available respecting a previous month where estimated information was used, the bill for the month in which the actual information became available shall be adjusted to reflect the difference between the actual and estimated information as if such information related to such later month. Neither Company nor Customer shall be entitled to interest on any adjustment.

5.6 Corrections

Notwithstanding any provision contained in this Tariff to the contrary, the correction of an error in a bill for Service rendered in a prior month, shall be made to the bill in accordance with the appropriate provision of this Tariff in effect at the time that the error was made. Company shall proceed with such correction in the month following the month that Company confirms the error. In the case of a disputed bill the provisions of paragraph 5.7 shall apply.

5.7 Disputed Bills

5.7.1 In the event Customer disputes any part of a bill, Customer shall nevertheless pay to Company the full amount of the bill when payment is due.

5.7.2 If Customer fails to pay the full amount of any bill when payment is due, Company may upon four (4) Banking Days written notice immediately suspend any or all Service being or to be provided to Customer provided however that such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company. If at any time during such suspension Customer pays the full amount payable to Company, Company shall within two (2) Banking Days recommence such suspended Service.

Following suspension, Company may, in addition to any other remedy that may be available to it, upon four (4) Banking Days written notice to Customer immediately:

(i) terminate any or all Service being or to be provided to Customer; and

(ii) declare any and all amounts payable now or in the future by Customer to Company for any and all Service to be immediately due and payable as liquidated damages and not as a penalty.

5.7.3 In the event that it is finally determined that Customer's monthly bill was incorrect and that an overpayment has been made, Company shall make reimbursement of such overpayment. Company shall pay interest on the overpayment to Customer, commencing from the date such overpayment was made and continuing until the date reimbursement is actually made, at a rate per annum equal to the Prime Rate plus one (1) percent.

6.0 POSSESSION AND CONTROL

6.1 Control

Gas received by Company shall be deemed to be in the custody and under the control of Company from the time it is received into the Facilities until it is delivered out of the Facilities.

6.2 Warranty

Customer warrants and represents it has the right to tender all gas delivered to Company.

7.0 GAS PRESSURES

7.1 The Gas Pressure At Receipt Points

The pressure of gas tendered by Customer to Company at any Receipt Point shall be the pressure, up to the Maximum Receipt Pressure, that Company requires such gas to be tendered, from time to time, at that Receipt Point.

7.2 Pressure Protection

Customer shall provide or cause to be provided suitable pressure relief devices, or pressure limiting devices, to protect the Facilities as may be necessary to ensure that the pressure of gas delivered by Customer to Company at any Receipt Point will not exceed one hundred ten (110%) percent of the Maximum Receipt Pressure.

7.3 The Gas Pressure At Delivery Points

The pressure of gas delivered by Company at any Delivery Point shall be the pressure available from the Facilities at that Delivery Point, provided that such pressure shall not exceed the Maximum Delivery Pressure.

8.0 GAS USED, GAS LOST AND MEASUREMENT VARIANCE

8.1 Company's Gas Requirements

Company may, at its option, either:

(a) take from all Customers at Receipt Points a quantity of gas equal to the aggregate quantity of any or all Gas Used, Gas Lost and Measurement Variance for any period; or

(b) arrange with a Customer or Customers or any other Persons at Receipt Points to take and pay for a quantity of gas equal to the aggregate quantity of any or all Gas Used, Gas Lost and Measurement Variance for any period.

8.2 Allocation of Gas Taken

If Company in any period exercises its option to take a quantity of gas as provided for in subparagraph 8.1 (a), each Customer's share of the quantity of such gas taken in such period will be a quantity equal to the product of the quantity of such gas taken in such period and a fraction, the numerator of which shall be the aggregate quantity of gas received by Company from Customer in such period at all of Customer's Receipt Points and the denominator of which shall be the aggregate quantity of gas received by Company from all Customers in such period at all Receipt Points.

8.3 Gas Received from Storage Facilities

Notwithstanding anything contained in this article 8.0, any gas received into the Facilities from a gas storage facility that was previously delivered into the gas storage facility through the Facilities shall not be included in any calculation, and shall not be taken into account in any allocation, of Company's gas requirements.

9.0 DELIVERY OBLIGATION

9.1 Company's Delivery Obligation

Subject to paragraph 9.2:

(a) Company's delivery obligation for any period where Company has exercised its option as provided for in subparagraph 8.1 (a), shall be to deliver to all Customers at all Delivery Points the quantity of gas Company determines was received from all Customers in such period at all Receipt Points, less all Customers share as determined under paragraph 8.2; and

(b) Company's delivery obligation, for any period where Company has exercised its option to purchase gas as provided for in subparagraph 8.1 (b), shall be to deliver to all Customers at all Delivery Points the quantity of all gas received from all Customers, other than gas taken from such Customers and paid for pursuant to subparagraph 8.1 (b), in such period at all Receipt Points.

9.2 Variance

Due to variations in operating conditions, the aggregate daily and monthly quantities of gas delivered to all Customers at all Delivery Points, adjusted as provided for in paragraph 9.1, will differ from the aggregate of the corresponding daily and monthly quantities of gas received from all Customers. Customers and Company shall co-operate to keep such differences to the minimum permitted by operating conditions and to balance out such differences as soon as practicable.

9.3 Operating Balance Agreements

Company may enter into agreements and other operating arrangements with any operator of a downstream pipeline facility interconnecting with the Facilities ("downstream operator") respecting the balancing of gas quantities to be delivered by Company and to be received by the downstream operator on any Day at the interconnection of the downstream facility and the Facilities (the "interconnection point"). This may include agreements and operating arrangements providing that for any Day a quantity of gas nominated by a Customer for delivery at the interconnection point may be deemed to have been delivered by Company and received by the downstream operator regardless of the actual flow of gas at the interconnection point on the Day.

9.4 Energy Content and Gas Quality

Gas delivered by Company to Customer at any of Customer's Delivery Points shall have the energy content and quality that results from the gas having been commingled in the Facilities.

9.5 Supply/Demand Balancing

The Terms and Conditions Respecting Customer's Inventories and Related Matters in Appendix "D" of the Tariff apply to all Service provided under this Tariff. Each Customer receiving Service is responsible for ensuring that Customer's Inventory is at all times within the Balanced Zone set out in Appendix "D". If Company determines that

Customer's Inventory for any Customer is not within the Balanced Zone, Company may upon notice suspend all or any portion of Service to Customer until Customer brings Customer's Inventory within the Balanced Zone, provided however that no such suspension shall relieve Customer of its obligation to pay any rate, toll, charge or other amount payable to Company.

9.6 Balancing Procedures

Company may from time to time establish procedures, consistent with the Terms and Conditions Respecting Customer's Inventories and Related Matters set forth in Appendix "D" of the Tariff.

9.7 Limitation on Delivery Obligation

Company shall be obligated to provide only such Service as can be provided through Company's operation of the existing Facilities pursuant to the terms and conditions of the Tariff.

9.8 Uniform Flow Rate

All deliveries of gas to Company at a Receipt Point shall be made in uniform hourly quantities to the extent practicable.

9.9 Emergency Response Compensation Event

If there is an ERC Event, Company shall determine Customer's Final ERC Adjustments in accordance with the Terms and Conditions Respecting Emergency Response Compensation set forth in Appendix "G" of the Tariff.

10.0 FINANCIAL ASSURANCES

10.1 Financial Assurance for Performance of Obligations

Company may request that Customer (or any assignee) at any time and from time to time provide Company with an irrevocable letter of credit or other assurance acceptable to Company, in form and substance satisfactory to Company and in an amount determined in accordance with paragraph 10.3 (the "Financial Assurance").

10.2 Failure to Provide Financial Assurance

Company may withhold the provision of new Service until Company has received a requested Financial Assurance.

If Customer fails to provide a requested Financial Assurance to Company within four (4) Banking Days of Company's request, Company may upon four (4) Banking Days written notice immediately suspend any or all Service being or to be provided to Customer provided however that any such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company. If at any time during such suspension Customer provides such Financial Assurance to Company, Company shall within two (2) Banking Days recommence such suspended Service.

If Customer fails to provide such Financial Assurance during such suspension, Company may, in addition to any other remedy that may be available to it, upon four (4) Banking Days written notice to Customer immediately:

(i) terminate any or all Service being or to be provided to Customer; and

(ii) declare any and all amounts payable now or in the future by Customer to Company for any and all Service to be immediately due and payable as liquidated damages and not as a penalty.

10.3 Amount of Financial Assurance

The maximum amount of Financial Assurance Company may request from a Customer (or assignee) shall be as determined by Company an amount equal to:

(i) for the provision of all Services, other than for Service referred to in paragraph (ii), the aggregate of all rates, tolls, charges or other amounts payable to Company for a period of seventy (70) Days. Provided however, the amount of Financial Assurance for all rates, tolls and charges other than demand charges shall be for a period of one hundred (100) Days, based on the daily average of the actual charges billed for Service for the preceding twelve (12) Month period with the initial forecast to be provided by Customer; and

(ii) for the provision of Service under subparagraph 5.1(ii) of Rate Schedule FT-D, the aggregate of all rates, tolls, charges or other amounts payable to Company for a period of seventy (70) Days plus one (1) Month for each remaining year of the term of such Service, up to a maximum of twelve (12) Months total.

The Financial Assurances for any new Facilities required to be installed or constructed by Company shall be determined in accordance with an agreement between Company and Customer for such Facilities.

11.0 INTERRUPTIONS AND CURTAILMENTS

11.1 Planned Interruptions

Provided that Company shall have given Customer at least forty-eight (48) hours notice, Company may interrupt, curtail or reduce Service for such periods of time as it may reasonably require for the purpose of effecting any repairs, maintenance, replacement or upgrading or other work related to the Facilities.

11.2 Unplanned Interruptions

Notwithstanding paragraph 11.1, in the event of unforeseen circumstances Company may interrupt, curtail or reduce Service for such periods of time as it may reasonably require without giving Customer the notice provided for in paragraph 11.1 provided that Company shall give notice of such interruption, curtailment or reduction as soon as is reasonably possible.

11.3 Notice of Change in Operations

Customer and Company shall give each other as much notice as is reasonably possible in the circumstances of expected temporary changes in the rates of delivery or receipt of gas, pressures or other operating conditions, together with the expected duration and the reason for such expected temporary changes.

11.4 Priority During Interruptions

11.4.1 At Receipt Points

During periods of interruption and curtailment Company may reduce any or all Service at Receipt Points in the following order:

(i) Firstly, Service under Rate Schedules IT-R and IT-S based on the priority provisions of the applicable Service Agreement until such Service has been reduced to zero (0); and

(ii) Secondly, Service under Rate Schedules FT-R, FT-RN, FT-X, FT-P, LRS, LRS-2 and LRS-3 on a prorata basis.

11.4.2 At Delivery Points

During periods of interruption and curtailment Company may reduce any or all Service at Delivery Points in the following order:

(i) Firstly, Service under Rate Schedules IT-D and IT-S based on the priority provisions of the applicable Service Agreement until such Service has been reduced to zero (0); and

(ii) Secondly, Service under Rate Schedules FT-D, FT-DW, FT-P, LRS-2, STFT, FT-A and FT-X on a prorata basis.

11.5 Customer’s Obligations

Notwithstanding any other provision in the Tariff, Customer agrees and acknowledges that any interruption and curtailment shall not under any circumstances suspend or relieve Customer from the obligation to pay any rate, toll, charge or other amount payable to Company.

12.0 FORCE MAJEURE

12.1 Notice of Force Majeure

In the event that either Company or Customer is rendered unable by reason of force majeure to perform in whole or in part any covenant or obligation in the Tariff, the performance of such covenant or obligation shall be suspended during the continuance of such force majeure, except as provided for in paragraph 12.3, upon the following terms and conditions:

(a) the party claiming suspension shall give written notice to the other party specifying full particulars of such force majeure as soon as is reasonably possible;

(b) the party claiming suspension shall as far as possible remedy such force majeure as soon as is reasonably possible; and

(c) the party claiming suspension shall give written notice to the other party as soon as is reasonably possible after such force majeure has been remedied.

12.2 Events of Force Majeure

For the purposes of these General Terms and Conditions, the term “force majeure” shall mean any cause not reasonably within the control of the party claiming suspension which by the exercise of due diligence such party is unable to prevent or overcome, including but without limiting the generality of the foregoing:

(a) lightning, storms, earthquakes, landslides, floods, washouts, and other acts of God;

(b) fires, explosions, ruptures, breakages of or accidents to the Facilities;

(c) freezing of pipelines or wells, hydrate obstructions of pipelines or appurtenances thereto, temporary failure of gas supply;

(d) shortages of necessary labour, strikes, lockouts or other industrial disturbances;

(e) civil disturbances, sabotage, acts of public enemies, war, blockades, insurrections, vandalism, riots, epidemics;

(f) arrests and restraints of governments and people;

(g) the order of any court, government body or regulatory body;

(h) inability to obtain or curtailment of supplies of electric power, water, fuel or other utilities or services;

(i) inability to obtain or curtailment of supplies of any other materials or equipment;

(j) inability to obtain or revocation or amendment of any permit, licence, certificate or authorization of any governmental or regulatory body, unless the revocation or amendment of such permit, licence, certificate or authorization was caused by the violation of the terms thereof or consented to by the party holding the same;

(k) the failure for any reason of a supplier of gas to Customer or a purchaser of gas from Customer to supply and deliver gas to Customer or to purchase and take delivery of gas from Customer;

(l) any claim by any third party that any covenant or obligation of such third party is suspended by reason of force majeure, including without limiting the generality of the foregoing any such claim by any transporter of gas to, from or for Company or Customer; and

(m) any other cause, whether herein enumerated or otherwise, not reasonably within the control of the party claiming suspension which by the exercise of due diligence such party is unable to prevent or overcome.

12.3 Customer's Obligations

Notwithstanding any other provision herein, Customer acknowledges and agrees that the occurrence of an event of force majeure shall not under any circumstances suspend or relieve Customer from the obligation to pay any rate, toll, charge or other amount payable to Company.

12.4 Lack of Funds not Force Majeure

Notwithstanding any other provision herein, Company and Customer agree that a lack of funds or other financial cause shall not under any circumstances be an event of force majeure.

12.5 Strikes and Lockouts

Notwithstanding any other provision herein, Company and Customer agree that the settlement of strikes, lockouts and other industrial disturbances shall be entirely within the discretion of the party involved.

12.6 Service During Force Majeure

In the event that the provision of Service is curtailed or interrupted by reason of force majeure, Company may during the continuance of such force majeure provide such Service as it deems appropriate.

13.0 INDEMNIFICATION

13.1 Customer's Liability

Customer shall be liable for and shall indemnify and save harmless Company from and against any and all claims, demands, suits, actions, damages, costs, losses and expenses of whatsoever nature arising out of or in any way connected, either directly or indirectly, with any act, omission or default arising out of the negligence of Customer.

13.2 Company's Liability

Company shall be liable for and shall indemnify and save harmless Customer from and against any and all claims, demands, suits, actions, damages, costs, losses and expenses of whatsoever nature arising out of or in any way connected, either directly or indirectly, with any act, omission or default arising out of the negligence of Company.

13.3 Limitations

Notwithstanding the provisions of paragraphs 13.1 and 13.2:

(a) Company and Customer shall have no liability for, nor obligation to indemnify and save harmless the other from, any claim, demand, suit, action, damage, cost, loss or expense which was not reasonably foreseeable at the time of the act, omission or default;

(b) Company shall have no liability to Customer, nor obligation to indemnify and save harmless Customer, in respect of Company's failure for any reason whatsoever, other than Company's wilful default, to provide Service pursuant to the provisions of Customer's Service Agreement;

(c) the failure by Company for any reason whatsoever to receive gas from Customer or deliver gas to Customer shall not suspend or relieve Customer from the obligation to pay any rate, toll, charge or other amount payable to Company; and

(d) Company shall have no liability to Customer, nor obligation to indemnify and save harmless Customer, in respect of Company providing Service to any Customer under Rate Schedule CO_2 and/or Rate Schedule PT.

14.0 EXCHANGE OF INFORMATION

14.1 Provision of Information

Company and Customer shall make available, on request by either made to the other, certificates, estimates and information as shall be in their possession, and as shall be reasonably required by the other.

14.2 Additional Information

Notwithstanding paragraph 14.1, Customer shall furnish Company with such estimated daily, monthly and annual quantities as Company may require, with respect to any Service provided or to be provided, together with any data that Company may require in order to design, operate and construct facilities to meet Customer's requirements.

15.0 MISCELLANEOUS PROVISIONS

15.1 Effect of Headings

The headings used throughout the Tariff are inserted for reference only and are not to be considered or taken into account in construing any terms or provision nor be deemed in any way to qualify, modify or explain any term or provision.

15.2 Words in Singular or Plural

In the interpretation of the Tariff words in the singular shall be read and construed in the plural and words in the plural shall be read and construed in the singular where the context so requires.

15.3 Preservation of Rights and Authority Under Act

Notwithstanding any of the provisions of the Tariff, Company and Customer reserve all their respective rights and authorities under the Act.

15.4 Governing Law

The Tariff shall be governed by and construed in accordance with the laws of the Province of Alberta and the applicable laws of Canada, and Company and Customers irrevocably submit to the jurisdiction of the courts of the Province of Alberta for the interpretation and enforcement of the Tariff.

15.5 Assignment

Customer shall not assign any Service Agreement, Schedule of Service or any Service without the prior written consent of Company.

15.6 No Interest in Facilities

Customer does not acquire any right to, title to or interest in the Facilities or any part thereof nor does Company dedicate any portion of the Facilities to Service for any Customer.

15.7 Forbearance

Forbearance to enforce any provision of the Tariff shall not be construed as a continuing forbearance to enforce any such provision.

15.8 Inconsistency

In the event that there is any inconsistency between any provision of these General Terms and Conditions, any provision of any Rate Schedule or any provision of any Service Agreement, the provision of the Service Agreement shall prevail over the Rate Schedule which in turn shall prevail over the General Terms and Conditions.

15.9 Amendment of Service Agreement

No amendment or variation of any term, condition or provision of any Schedule of Service or Service Agreement shall be of any force or effect unless in writing and signed by Company.

15.10 Priority for New or Additional Service

Company may from time to time establish procedures respecting priority of entitlement for Customers seeking new or additional Service.

15.11 Establishment of Procedures and Pilot Projects

Company may from time to time establish procedures, including procedures for carrying out and evaluating any pilot projects Company determines to be necessary or desirable, respecting or relating to or affecting any Service or any term, condition or provision contained within the Tariff.

15.12 Conversion of Service Agreements to Energy Units

(a) Effective November 1, 2006, for any Service Agreements under Rate Schedules FT-D, FT-DW and STFT, the Export Delivery Contract Demand set out in each new Schedule of Service shall be expressed in energy units (GJ).

(b) Effective November 1, 2006, for any Service Agreements under Rate Schedules FT-D, FT-DW and STFT, the Export Delivery Contract Demand set out in each existing Schedule of Service shall be converted to GJ using the following Export Delivery Point energy conversion rates:

Alberta-British Columbia Border	37.98 MJ per m^3
Alberta-Montana Border	37.71 MJ per m^3
Boundary Lake Border	39.55 MJ per m^3
Cold Lake Border	37.52 MJ per m^3
Demmitt #2 Interconnect	39.57 MJ per m^3
Empress Border	37.52 MJ per m^3
Gordondale Border	40.05 MJ per m^3
McNeill Border	37.57 MJ per m^3
Unity Border	37.78 MJ per m^3

APPENDIX "D"
TO
GAS TRANSPORTATION TARIFF
OF
NOVA GAS TRANSMISSION LTD.

TERMS AND CONDITIONS RESPECTING CUSTOMER'S INVENTORIES AND RELATED MATTERS

TERMS AND CONDITIONS RESPECTING
CUSTOMER'S INVENTORIES AND RELATED MATTERS

1.0 DEFINITIONS

1.1 Capitalized terms used in this Appendix have the meanings attributed to them in the Tariff unless otherwise defined in this Appendix.

In this Appendix:

1.2 "Balanced Zone" shall mean for each Day, subject to Articles 6.0 and 7.0, the range of a Customer's Inventory between the amounts determined as follows:

(i) the positive value of the greater of:

(a) two (2) TJ's; or

(b) the sum of:

(I) four (4) percent of the quotient obtained when the sum of the Total Quantity for all Receipt Points in the Billing Month for a Customer (excluding all Total Quantity in relation to storage facilities and title transfers) is divided by the total number of days in the Billing Month; and

(II) four (4) percent of the quotient obtained when the sum of the Total Quantity for all Delivery Points in the Billing Month for a Customer (excluding all Total Quantity in relation to storage facilities and title transfers) is divided by the total number of days in the Billing Month; and

(ii) the negative value of the amount determined in subparagraph 1.2(i).

1.3 “Daily Plan” shall mean the written plan Customer shall provide to Company which shall set out all information on how Customer will comply with this Appendix, including all known or anticipated changes to Customer’s Inventory for the Day.

1.4 “NIT List” shall mean the list provided to Company by Customer, of at least 10 active title transfers of Customer’s Inventory excluding title transfers between:

(i) agency accounts;

(ii) affiliates; and

(iii) Customers whose marketing and management services are provided by the same entity.

1.5 “Pipeline Tolerance Level” shall mean the quantity of linepack in the Facilities determined by Company from time to time to enable the optimum operation of the Company’s Facilities.

1.6 “Total Quantity” shall mean the aggregate energy calculated for a Billing Month for a Receipt Point or a Delivery Point.

2.0 DELIVERY NOMINATIONS

2.1 Company may refuse to accept an increase in a Nomination placed on behalf of a Customer at any of Customer's Delivery Points unless two (2) hours prior to the time that such Nomination is to take effect Company has been able to confirm through Common Stream Operators that:

(i) the aggregate of the Flows at all of Customer's Receipt Points will equal the aggregate of the Flows at all of Customer's Delivery Points when the increase in Nomination takes effect; and

(ii) Customer will have gas available to meet the Customer's receipt Nominations at all of Customer's Receipt Points when the increase in Nomination takes effect.

3.0 DETERMINATION AND ALLOCATION OF FLOWS

3.1 Company will determine and allocate Flows at Receipt Points and Delivery Points in the following manner:

(i) Flow at a Receipt Point will be determined as follows:

(a) Company will obtain an estimate of the Flow at a Receipt Point from the Common Stream Operator, if available, and will verify, or revise if deemed necessary by Company, the information obtained based on electronically gathered data, if available, or, if electronically gathered data is not available for any reason, based on Company's estimate made by taking into account the most recent measurement data, subsequent changes in Nominations and available historical data.

(b) If an estimate of the Flow at a Receipt Point is unavailable from the Common Stream Operator for any reason, Company will estimate the Flow based on electronically gathered data, if available, or, if electronically gathered data is not available for any reason, by taking into account the most recent measurement data, subsequent changes in Nominations and available historical data.

(ii) Flow at a Receipt Point will be allocated to each Customer at a Receipt Point based on the allocation made by the Common Stream Operator, if available, or, if for any reason an allocation for any Customer is unavailable from the Common Stream Operator, in the same proportion as the Customer's Nomination at the Receipt Point is of the aggregate of all Nominations for all Customers at the Receipt Point.

(iii) Flow at a Delivery Point will be estimated based on electronically gathered data, if available, or, if electronically gathered data is not available for any reason, by taking into account the most recent measurement data, subsequent changes in Nominations and available historical data.

(iv) Flow at a Delivery Point will be allocated to each Customer at a Delivery Point in the same proportion as such Customer's Nomination at the Delivery Point is of the aggregate of all Nominations for all Customers at the Delivery Point.

3.2 Company will determine and allocate Total Quantity at Receipt Points and Delivery Points as follows:

(i) Total Quantity at Receipt Points for a Billing Month will be determined based on final measurement data obtained by Company in the month following the Billing Month.

(ii) Total Quantity at a Receipt Point for a Billing Month will be allocated by the Common Stream Operator to each Customer receiving Service at the Receipt Point during the Billing Month.

(iii) Total Quantity at Delivery Points for a Billing Month will be determined based on final measurement data obtained by Company in the month following the Billing Month.

(iv) Total Quantity at a Delivery Point for a Billing Month will be allocated to each Customer receiving Service at the Delivery Point during the Billing Month in the same proportion as such Customer's Nomination at the Delivery Point is of the aggregate of all Nominations for all Customers at the Delivery Point.

3.3 Company's determination and allocation of Flows and Total Quantity at Receipt Points and Delivery Points, made in accordance with these terms and conditions, will be conclusive and binding on Customers for the purposes of any action taken by Company pursuant to these terms and conditions or any provision contained within the Tariff.

4.0 DAILY BALANCED ZONE REQUIREMENTS

4.1 On each Day Customer shall ensure that such Customer's Inventory shall be within the Balanced Zone at the end of such Day. Customer shall have until 10:30 MST on the following Day to get Customer's Inventory within the Balanced Zone. It is the Customer's responsibility to monitor Customer's Inventory and balancing requirements utilizing the information tools provided by Company. Company may on any Day request Customer to provide a Daily Plan and Customer shall provide such Daily Plan to Company on or before 16:00 hours (Calgary clock time) on such Day.

4.2 If Customer fails to comply with paragraph 4.1 on any Day, Company, to the extent necessary to ensure compliance with paragraph 4.1, may:

(i) Cancel prior to the end of the next Day all or a portion of any title transfer(s) set out in NIT List. If Customer has not provided Company with a NIT List, Company shall be entitled to randomly select which title transfer(s) shall be reduced and/or cancelled to ensure Customer's Inventory is within Customer's

Balanced Zone, commencing with the shortest term title transfer(s) and excluding title transfers between:

(a) agency accounts;

(b) affiliates; and

(c) Customers whose marketing and management services are provided by the same entity.

Any title transfer(s) selected by Company to balance a Customer's Inventory with a term longer than one day shall be deemed to be cancelled for the balance of that term. After such cancellation, Company shall use reasonable efforts to contact and advise Customer and the counter party to the title transfer that all or a portion of the title transfer has been cancelled;

(ii) Decrease Customer's current Day Nominations; and

(iii) Decrease Customer's allocations received from the Common Stream Operator to match current Day Nominations.

4.3 If Customer fails to comply with paragraph 4.1, and Company fails to obtain Customer compliance of paragraph 4.1 by virtue of implementing paragraph 4.2 for three (3) consecutive Days, Company, in addition to any other remedy it may have, shall be entitled to suspend on two (2) hours written notice to Customer:

(i) All or a portion of Service to such Customer, provided however such suspension shall not relieve Customer of its obligation to pay any rate, toll charge or other amount payable to Company; and

(ii) Customer's access to any electronic tool that allows Customer to transact business on Company's Facilities, provided however such suspension shall not relieve

Customer of its obligation to pay any rate, toll charge or other amount payable to Company.

5.0 DISCRETION

5.1 For any Day a Customer's Inventory may be outside the Balanced Zone by an amount equal to the sum of the following:

(i) The difference between the estimated extrapolated physical receipt flow at 16:00 (Calgary clock time) and the finalized physical receipt quantity at the end of such Day;

(ii) The difference between the forecasted extraction quantities as provided to Company by the Extraction Plants, at 16:00 (Calgary clock time) and the extraction quantities as provided to Company by the Extraction Plants, at the end of such Day;

(iii) Historical changes that are applied by Company to Customer's Inventory during the Day; and

(iv) Net change for such Day to a border delivery nomination between the requested quantity and allowable quantity when Company implements a border delivery restriction and notification of such restriction to Customer occurs after 16:00 (Calgary clock time).

Provided however, Customer shall cause Customer's Inventory to be within the Balanced Zone by the end of the Day following such Day.

5.2 If Customer fails to comply with paragraph 5.1, Company may implement the remedies set out in subparagraphs 4.2 (i), (ii), and (iii). If Customer fails to comply with paragraph 5.1 for three consecutive Days, Company may implement the remedies in subparagraphs 4.3(i) and (ii).

6.0 CHANGES TO PIPELINE TOLERANCE LEVEL

6.1 Company may from time to time change the Pipeline Tolerance Level, which shall result in the following changes to Customer's Balanced Zone:

(i) If Company determines the Pipeline Tolerance Level needs to be increased, the Customer's Balanced Zone shall be between zero and the amount determined in subparagraph 1.2(i); or

(ii) If Company determines the Pipeline Tolerance Level needs to be decreased, the Customer's Balanced Zone shall be between zero and the amount determined in subparagraph 1.2(ii).

6.2 If on any Day Company changes the Pipeline Tolerance Level prior to 12:00 hours (Calgary clock time) Customer's Inventory must be within Customer's changed Balanced Zone by the end of such Day.

6.3 If on any Day Company changes the Pipeline Tolerance Level on or after 12:00 hours (Calgary clock time) the changed Pipeline Tolerance Level shall be effective at the start of the next Day and Customer's Inventory must be within Customer's changed Balanced Zone by the end of such next Day.

6.4 Notwithstanding paragraphs 6.2 and 6.3 Customer shall continue to comply with paragraph 4.1.

6.5 If an ERC Event (as defined in Appendix "G" of the Tariff) or Force Majeure (as set out in Article 12.0 of the General Terms & Conditions of the Tariff) occurs, and Company determines, in it's sole discretion, that the Pipeline Tolerance Level must be changed for the safe and effective operation of the Facilities, Company may, notwithstanding paragraphs 6.2 and 6.3, immediately change the Pipeline Tolerance Level to a level determined by Company. Customer's Inventory shall be within Customer's changed

Balanced Zone within twenty-four (24) hours from the effective time of the revised Pipeline Tolerance Level as posted by Company on its electronic bulletin board.

7.0 NIT ONLY CUSTOMERS

7.1 Notwithstanding anything contained in this Appendix, a Customer who does not have any physical receipt quantities or any physical delivery quantities, excluding Total Quantity in relation to storage facilities, shall not be entitled to a Balanced Zone and must balance to zero (0) at the end of each Day.

7.2 If on any Day, Company determines such Customer did not balance to zero (0) at the end of such Day, Company shall be entitled to cancel all or a portion of any title transfer(s) set out in NIT List, as Company determines necessary to ensure Customer balances to zero (0). If Customer has not provided Company with a NIT List, Company shall be entitled to randomly select which title transfer(s) shall be cancelled and/or reduced, commencing with the shortest term of title transfer(s) and excluding title transfers between:

(a) agency accounts;

(b) affiliates; and

(c) Customers whose marketing and management services are provided by the same entity.

Any title transfer(s) selected by Company to balance a Customer's Inventory with a term longer than one day, shall be deemed to be cancelled for the balance of that term. After such cancellation, Company shall use reasonable efforts to contact and advise the Customer and the counter party to the title transfer that all or a portion of the title transfer has been cancelled.

7.3 If Customer fails to comply with paragraph 7.1 for three (3) consecutive Days, Company, in addition to any other remedy it may have, shall be entitled to suspend on two (2) hours written notice to Customer:

(i) All or a portion of Service to such Customer, provided however such suspension shall not relieve Customer of its obligation to pay any rate, toll charge or other amount payable to Company; and

(ii) Customer's access to any electronic tool that allows Customer to transact business on Company's Facilities, provided however such suspension shall not relieve Customer of its obligation to pay any rate, toll charge or other amount payable to Company.

8.0 ADMINISTRATION OF CUSTOMER'S INVENTORIES AT MONTH END

8.1 On one (1) occasion each month Company, using the Total Quantity and allocation of Total Quantity for each of Customer's Receipt Points and Delivery Points on the pipeline system, will determine Customer's Inventory for each Customer receiving Service in the Billing Month. Company's monthly determination of Customer's Inventory will incorporate the revision of any allocation of Flow provided to Company in respect of any prior period and the reallocation of the Flow among Customers.

8.2 Company will notify a Customer if such Customer's Inventory is negative. A Customer may reduce such negative amount through one (1) or a series of inventory transfers carried out in accordance with Company's Terms and Conditions Respecting Title Transfers. If Customer does not reduce such negative Customer's Inventory through title transfers then such negative amount shall be subtracted from Customer's Inventory each Day at a rate equivalent to the greater of:

(i) the absolute value of one thirtieth ($1/30^{th}$) of such negative amount; and

(ii) 100 GJ.

8.3 Company will notify Customer if such Customer's Inventory is positive. A Customer may reduce such positive amount through one (1) or a series of inventory transfers carried out in accordance with Company's Terms and Conditions Respecting Title Transfers. If Customer does not reduce such positive Customer's Inventory through title transfers then such positive amount shall be added to Customer's Inventory each Day at a rate equivalent to the greater of:

(i) one thirtieth ($1/30^{th}$) of such amount; and

(ii) 100 GJ.

9.0 CUSTOMER'S RESPONSIBILITY

9.1 Customer is responsible to comply with this Appendix twenty four (24) hours a Day, even if Company is unable to contact Customer on such Day.

APPENDIX "G"
TO
GAS TRANSPORTATION TARIFF
OF
NOVA GAS TRANSMISSION LTD

TERMS AND CONDITIONS RESPECTING
EMERGENCY RESPONSE COMPENSATION

TERMS AND CONDITIONS RESPECTING
EMERGENCY RESPONSE COMPENSATION

1.0 DEFINITIONS

1.1 Capitalized terms used in this Appendix have the meanings attributed to them in the Tariff unless otherwise defined in this Appendix.

In this Appendix:

1.2 "Allocation" shall mean the expected gas Flow allocated to each Customer by CSO at a Receipt Point and used by Company to estimate physical gas Flows for each Customer at such Receipt Point.

1.3 "Amended ERC RAF" shall mean the amended ERC RAF, provided by CSO to Company pursuant to paragraph 6.1, which revises a Customer's Final Event Energy.

1.4 "Area of Impact" shall mean that portion of the Facilities determined by Company, to be directly affected by an ERC Event.

1.5 "CGPR" shall mean the monthly publication entitled "Canadian Gas Price Reporter".

1.6 "Claims" shall mean any claims, demands, actions, causes of actions, damages (including without limitation indirect, incidental, consequential, exemplary, punitive, loss of profits, revenue, or similar damages), deficiencies, losses, liabilities, expenses, or costs of any nature and kind whatsoever (including without limitation legal costs on a solicitor and his own client basis and costs of investigation).

1.7 "Duration of the ERC Event" shall mean the period of time (rounded to the closest half hour) commencing at the time the first Plant is requested by Company to reduce Flow and ending two hours after the time the last Plant has been requested by Company to resume Flow to the rate determined by Company. Duration of the ERC Event shall be determined by Company and shall not exceed 48 hours.

1.8 “Emergency Response Compensation Event” or “ERC Event” shall mean an event caused by a facility failure on Company’s Facilities or on the facilities of a downstream pipeline directly connected to the Facilities, which results in the operating pressure of the affected Facilities exceeding the Maximum Operating Pressure of such Facilities and Company implementing the ERC Procedure. An ERC Event shall not include an event where:

(i) the overpressuring of the Facilities is caused by supply/demand account imbalances or gas supply production in excess of nominations; or

(ii) Company reduces Flow at all Receipt Points in Area of Impact to zero; or

(iii) overpressuring is alleviated by Company implementing the interruption and curtailment provisions set out in Article 11 of the General Terms and Conditions of the Tariff.

1.9 “ERC” shall mean the emergency response compensation that may be made available to Customer or provided by Customer by way of a Final ERC Adjustment.

1.10 “ERC Procedure” shall mean the terms and conditions of this Appendix G.

1.11 "ERC RAF" shall mean the ERC receipt allocation form attached as Schedule “A” and provided by Company to CSO in accordance with paragraph 5.5.

1.12 “Estimated Event Energy” shall mean an amount of energy measured in GJs flowed by a Customer at a Receipt Point in the Area of Impact for the Duration of the ERC Event, based on unfinalized custody transfer measurement as measured by Company and the daily Allocation, at such Receipt Point, as determined by Company, and as may be revised in accordance with paragraph 5.5.

1.13 “Event Price” shall mean the average price of all gas trades on NGX for the period commencing at the start of the ERC Event and ending at 5:00 p.m. MST or MDT, as the case may be, on the day the ERC Event terminates. If the ERC Event terminates on a non-business day, the period shall end at 5:00 p.m. MST or MDT, as the case may be, on the next business day. If during such period the number of gas trades on NGX is less than twenty (20) and the aggregate volume of gas traded is less than 200 MMcf/day then the average of the prices published in the CGPR for such period plus one business day will be used to determine the Event Price.

1.14 "Fair Share" shall mean the amount of Flow a Customer should have flowed for the Duration of the ERC Event if each CSO at each Receipt Point in the Area of Impact was able to reduce the Flow for each Customer by a prorata amount determined by Company in accordance with paragraph 5.3.

1.15 "Final ERC Adjustment" shall mean the debit or credit adjustment, as the case may be, to Customers bill for Service determined by Company in accordance with paragraph 5.6.

1.16 "Final Event Energy" shall mean the Customer's Estimated Event Energy subject to any revisions set out on the ERC RAF and provided by the CSO to Company in accordance with paragraph 5.5.

1.17 "Flow After Initial Response" shall mean the Flow specified by CSO in the Plant Survey that the CSO will reduce to within the Initial Response Time.

1.18 "Flow After Remaining Response" shall mean the Flow specified by CSO in the Plant Survey that the CSO will reduce to within the Remaining Response Time.

1.19 "Flow Proration Factor" shall mean the aggregate of all Customers' estimated average energy Flow, based on unfinalized custody transfer measurement as measured by Company, at all Receipt Points in the Area of Impact for the Duration of the ERC Event divided by the aggregate of all Customers' estimated energy Flow, based on unfinalized custody transfer measurement as measured by Company, at all Receipt Points in the Area of Impact immediately prior to the ERC Event.

1.20 "Gas Balance Recovery Period" shall mean the period of thirty days over which the Company recovers from Customer the difference between such Customer's month end estimated inventory and month end actual inventory.

1.21 "Gas Balance Recovery Price" shall mean the price per GJ calculated as follows:

$$\text{GBRP} = \left(\frac{A}{30} \times B\right) + \left(\frac{C}{30} \times D\right)$$

Where:

"GBRP"	=	Gas Balance Recovery Price;
"A"	=	the number of days between the date the Gas Balance Recovery Period associated with the ERC Event begins and the last day of the month following the month of the ERC Event;
"B"	=	the average of the same day prices (as defined by Natural Gas Exchange Inc. on its' website) per GJ for the gas traded on NGX for the period described in "A" above;
"C"	=	30 - "A"; and
"D"	=	the volume weighted average of near month prices (as defined by Natural Gas Exchange Inc. on its' website) per GJ for the gas traded on NGX during the period described in "A" above.

1.22 "Initial ERC Adjustment" shall mean the initial adjustment determined by Company in accordance with paragraph 5.4.

1.23 "Initial ERC Energy" shall mean the difference, in energy, between what Customer flowed and what Customer should have flowed based on its' Fair Share at each Receipt Point in the Area of Impact, for the Duration of the ERC Event as determined by Company in accordance with paragraph 5.3.

1.24 "Initial Response Time" shall mean the length of time, up to a maximum of two hours, specified by CSO in the Plant Survey that the CSO is able to reduce Flow to its Flow After Initial Response when requested to do so by Company regardless of the day or time of day.

1.25 "Maximum Operating Pressure" shall mean the maximum licensed operating pressure of the applicable Facilities.

1.26 "Minimum Turndown" shall mean the minimum Flow of gas a Plant is required to process in order to maintain continuous operations.

1.27 "NGX" shall mean the electronic trading and clearing services provided by Natural Gas Exchange Inc.

1.28 "NrG Highway" shall mean the electronic services owned and operated by NrG Information Services Inc. and used by Company and Customer to conduct electronic commerce.

1.29 "Plant" shall mean a gas processing facility connected to the Facilities.

1.30 "Plant Survey" shall mean the survey to be completed by CSOs upon Company request, substantially in the form attached as Schedule B.

1.31 "Prior Period ERC Adjustment" shall mean the debit or credit adjustment, as the case may be, to Customer's bill for Service determined by Company in accordance with paragraph 6.2.

1.32 "Prior Period Recovery Price" shall mean the price per GJ calculated as follows:

$$\text{PPRP} = \left(\frac{A}{30} \times B\right) + \left(\frac{C}{30} \times D\right)$$

Where:

"PPRP"	=	Prior Period Recovery Price;
"A"	=	the number of days between the date the Gas Balance Recovery Period associated with the Amended ERC RAF begins and the last day of the month in which Company processes the Amended ERC RAF;
"B"	=	the average of the same day prices (as defined by Natural Gas Exchange Inc. on its' website) per GJ for the gas traded on NGX for the period described in "A" above;
"C"	=	30 - "A"; and
"D"	=	the volume weighted average of near month prices (as defined by Natural Gas Exchange Inc. on its' website) per GJ for the gas traded on NGX during the period described in "A" above.

1.33 "Remaining Response Time" shall mean the length of time greater than two hours, specified by the CSO in the Plant Survey that the CSO is able to reduce Flow to its' Flow After Remaining Response when requested to do so by Company regardless of the day or time of day.

1.34 "Renomination" shall mean a change in each Customer's Nomination at an Export Delivery Point requested by the operator of the downstream pipeline connected to the Facilities.

2.0 PURPOSE

2.1 In the event of an ERC Event, Company relies on Plants in the Area of Impact to reduce Flows to mitigate a potential overpressure situation and the release of gas, which could threaten public safety and integrity of the Facilities. These ERC Procedures attempt to provide fair and equitable treatment to Customers who reduce Flow during an ERC Event through Final ERC Adjustments.

3.0 APPLICABILITY

3.1 The ERC shall:

(i) only apply to Customers at Receipt Points in the Area of Impact;

(ii) only apply for the Duration of the ERC Event; and

(iii) not apply to connecting pipelines and storage facilities.

3.2 An ERC Event shall terminate when the Company determines the risk of overpressuring is managed through:

(i) the reduction of Service in accordance with Article 11.0 of the General Terms and Conditions of the Tariff;

(ii) the receipt of a Renomination and utilization of the supply/demand balancing procedures in Appendix “D”; or

(iii) the placement of affected Facilities back into service.

4.0 MANAGEMENT OF THE ERC EVENT

4.1 In the event that Company has determined an ERC Event has commenced, then:

(i) Company will respond initially by diverting gas to the extent possible to interconnecting facilities where operating balance agreements exist and Delivery Points within the Area of Impact;

(ii) Company will contact CSOs at Receipt Points in the Area of Impact and request Flow reductions to the Flow After Initial Response and/or the Flow After Remaining Response or such other volume as Company and CSO may agree to. CSO will, to the extent possible, reduce its' Flow to the Flow After Initial Response and/or the Flow After Remaining Response within the Initial Response Time and/or the Remaining Response Time, as the case may be;

(iii) Company will use reasonable efforts to notify Customers, within two hours from the commencement of the ERC Event, of the ERC Event and the estimated Area of Impact through an NrG Highway bulletin which will trigger a paging notification;

(iv) Company will use reasonable efforts to notify Customers, within four hours from the commencement of the ERC Event, of the estimated Flow Proration Factor through an NrG Highway bulletin;

(v) Company will forward an ERC GS072 allocation form (which sets out the Allocations) to all CSOs at all Receipt Points in the Area of Impact and the CSO will complete and return such form, if necessary, within four (4) hours of CSOs requested effective time; and

(vi) Company will not allow Nomination increases at Receipt Points in the Area of Impact during the ERC Event.

4.2 Each Customer at Receipt Points in the Area of Impact shall be responsible for managing its' daily Customer's Inventory in accordance with Appendix "D" of the Tariff.

4.3 CSOs shall within three business days after the termination of the ERC Event:

(i) review the "Daily Common Stream Operator Report" (GS071); and

(ii) notify Company of any Receipt Point measurement variance.

4.4 If CSOs fail to notify Company of any measurement variances in accordance with paragraph 4.3, Company shall use the unfinalized custody transfer measurement set out in the GS071 to determine the Initial ERC Adjustments in accordance with paragraph 5.4.

5.0 DETERMINATION OF FINAL ERC ADJUSTMENT

5.1 Upon termination of the ERC Event, Company shall determine the Final ERC Adjustment for each Customer and Company shall apply the Final ERC Adjustment as a separate line item to the Customer's bill for Service two months following the month in which the ERC Event terminated. If Customer's Final ERC Adjustment is a negative amount, the Customer shall receive a credit for such amount on its' bill for Service. If Customer's Final ERC Adjustment is a positive amount, the Customer shall receive a debit for such amount on its' bill for Service and Customer shall pay such amount in accordance with Article 5.0 of the General Terms and Conditions of the Tariff. The aggregate of all Final ERC Adjustment debits for all Customers shall equal the aggregate of all Final ERC Adjustment credits for all Customers for the ERC Event.

5.2 Company shall determine the Final ERC Adjustment for each Customer by applying the following three steps:

(i) calculation of the aggregate Initial ERC Energy in accordance with paragraph 5.3;

(ii) calculation of the Initial ERC Adjustment in accordance with paragraph 5.4; and

(iii) calculation of the Final ERC Adjustment in accordance with paragraph 5.6.

5.3 Calculation of Initial ERC Energy

The aggregate Initial ERC Energy for each Customer at all Receipt Points in the Area of Impact shall be equal to the sum of the Initial ERC Energy for such Customer at each

Receipt Point in the Area of Impact. The Initial ERC Energy for each Customer at each Receipt Point shall be determined as follows:

$$IE = (A - B) \times \frac{t}{24\text{hr/day}}$$

Where:

"IE" = Initial ERC Energy for each Customer at each Receipt Point in the Area of Impact;

"A" = Customer's estimated average energy Flow for the Duration of the ERC Event, based on unfinalized custody transfer measurement as measured by Company and the daily Allocation, at such Receipt Point;

"B" = Customer's Fair Share at such Receipt Point determined as follows; and

$$B = C \times D$$

Where:

"C" = Flow Proration Factor for the Area of Impact; and

"D" = Customer's estimated average energy Flow immediately prior to the ERC Event, based on unfinalized custody transfer measurement as measured by Company and the daily Allocation, at such Receipt Point;

"t" = Duration of the ERC Event.

5.4 Calculation of Initial ERC Adjustment

Company shall determine each Customer's Initial ERC Adjustment for all Receipt Points in the Area of Impact as follows:

IA = AIE x EP

Where:

"IA"	=	Customer's Initial ERC Adjustment for all Receipt Points in the Area of Impact;
"AIE"	=	such Customer's aggregate Initial ERC Energy calculated in accordance with paragraph 5.3; and
"EP"	=	Event Price.

5.5 Final ERC Allocation

Company will use reasonable efforts to send an ERC RAF, within five business days after the termination of the ERC Event, to each CSO for each Receipt Point within the Area of Impact. The CSO shall to the extent necessary revise a Customer's Estimated Event Energy set out in the ERC RAF. Any revisions to a Customer's Estimated Event Energy must not change the total Estimated Event Energy set out in the ERC RAF. The CSO shall return the revised ERC RAF to Company on or before the "reply no later than" date set out on the ERC RAF. If CSO does not provide Company with the revised ERC RAF on or before such date Company shall use the Estimated Event Energy for the purpose of determining Customer's Final ERC Adjustment and as a result the Final ERC Adjustment will be equal to the Initial ERC Adjustment. If CSO does provide Company with the revised ERC RAF on or before such date, Company shall use such revisions to Customer's Estimated Event Energy for the purpose of determining Customer's Final ERC Adjustment.

5.6 Calculation of Final ERC Adjustment

The Company shall determine each Customer's Final ERC Adjustment for all Receipt Points in the Area of Impact as follows:

$$FA = IA + F$$

Where:

"FA"	=	Customer's Final ERC Adjustment for all Receipt Points in the Area of Impact;
"IA"	=	Customer's Initial ERC Adjustment as calculated in accordance with paragraph 5.4; and
"F"	=	the aggregate of the following amounts determined for each of Customer's Receipt Points in the Area of Impact:

$$F = (G - H) \times I$$

Where:

"G"	=	Customer's Final Event Energy at each Receipt Point in the Area of Impact;
"H"	=	Customer's Estimated Event Energy; and
"I"	=	Gas Balance Recovery Price.

6.0 PRIOR PERIOD ADJUSTMENTS

6.1 Company will calculate a Prior Period ERC Adjustment if:

(i) CSO provides Company with an Amended ERC RAF within three months from the "reply no later than" date set out on the ERC RAF;

(ii) at least one Customer’s Final Event Energy is adjusted by at least 200 GJs; and

(iii) Company has not received a prior Amended ERC RAF for the Receipt Point for the ERC Event.

6.2 Calculation of Prior Period ERC Adjustment

The aggregate Prior Period ERC Adjustment for each Customer at all Receipt Points affected by the Amended ERC RAFs for the ERC Event shall be equal to the sum of the Prior Period ERC Adjustments for such Customer at each Receipt Point. The Prior Period Adjustment for such Customer at each Receipt point shall be determined as follows:

$$PPA = (J - K) \times L$$

Where:

“PPA”	=	Prior Period ERC Adjustment for the affected Customer at each Receipt Point;
“J”	=	Customer’s final energy provided by the CSO on the Amended ERC RAF;
“K”	=	Customer’s Final Event Energy; and
“L”	=	Prior Period Recovery Price.

6.3 Company shall apply the aggregate Prior Period ERC Adjustment as a separate line item on Customer’s bill for Service in the month following the receipt by Company of the Amended ERC RAF. If Customer’s aggregate Prior Period ERC Adjustment is a negative amount, Customer shall receive a credit for such amount on its’ bill for Service. If Customer’s aggregate Prior Period ERC Adjustment is a positive amount, Customer shall receive a debit for such amount on its' bill for Service and Customer shall pay such amount in accordance with Article 5.0 of the General Terms and Conditions of the Tariff.

7.0 PLANT SURVEY

7.1 The CSO shall complete and provide Company with the Plant Survey containing information for the upcoming gas year, on or before the date requested by Company.

7.2 Utilizing the completed Plant Surveys from the CSOs, Company will designate each Receipt Point as either a "primary" or a "secondary" Receipt Point for each ERC Event. A Receipt Point will be designated as "primary" if the current Flow less the Flow After Initial Response for such Receipt Point is 560 10^3m^3/day or greater. A Receipt Point will be designated as "secondary" if the current Flow less the Flow After Initial Response for such Receipt Point is less than 560 10^3m^3/day.

7.3 In an attempt to minimize an overpressure situation in the most effective and timely manner Company will utilize the "primary" Receipt Points taking into account the following:

(i) hours of operation of the Plant;

(ii) current Flow less the Flow After Initial Response; and

(iii) Initial Response Times.

7.4 Company will utilize "secondary" Receipt Points when the Flow reduction required for the ERC Event exceeds the aggregate of the current Flows less the Flow After Initial Responses for all the "primary" Receipt Points within the Area of Impact.

7.5 If possible, Company will attempt to vary Receipt Points utilized by Company between ERC Events.

8.0 REVIEW

8.1 For the purposes of reviewing the effectiveness of the ERC Procedure, Company shall maintain a record of the following :

(i) the cause of the ERC Event;

(ii) the Duration of the ERC Event;

(iii) the Receipt Points in the Area of Impact;

(iv) the CSOs contacted during the ERC Event;

(v) the Flow reductions requested by Company at Receipt Points in the Area of Impact;

(vi) the Customers' Estimated Event Energy, Final Event Energy and final energy provided by the CSO on the Amended ERC RAF;

(vii) the Event Price, the Gas Balance Recovery Price, and the Prior Period Recovery Prices; and

(viii) the calculation of the Initial ERC Adjustments, the Final ERC Adjustments, and the Prior Period ERC Adjustments (if any).

8.2 Company's records shall form the sole basis for determining the Initial ERC Adjustments and Final ERC Adjustments. Within a reasonable time after the ERC Event, Company shall provide CSOs and Customers affected by the ERC Event with a report summarizing the calculations of the Initial ERC Adjustment, Final ERC Adjustment and Prior Period ERC Adjustments (if any).

9.0 LIABILITY, INDEMNIFICATION AND FORCE MAJEURE

9.1 Liability of Company

Company shall not be liable to Customer, CSOs or any other person for any Claims resulting from, or arising in any manner directly or indirectly out of the ERC Procedure or any act or omission by the Company relating to the ERC Procedure, except any Claim which arises directly from any negligent act or omission of Company in applying the ERC Procedure.

9.2 Customer Indemnification

Customer shall be liable to and shall indemnify, defend and save harmless Company, its directors, officers, employees, agents, representatives, successors, assigns and shareholders, and each of them at all times, from and against any Claims, resulting from, or arising in any manner directly or indirectly out of the ERC Procedure or any act or omission by Company relating to the ERC Procedure, except any Claim which arises directly from any negligent act or omission of Company in applying the ERC Procedure.

9.3 Force Majeure

The ERC Procedure shall not prevent or otherwise restrict Company from declaring force majeure if the ERC Event constitutes a force majeure as defined in Article 12 of the General Terms and Conditions of the Tariff.

Schedule “A”

ERC Receipt Allocation Form

```
                                                        1999-01-08  16:13:44.2
GS122             NOVA GAS TRANSMISSION LTD.                         PAGE:   1
                  ERC RECEIPT ALLOCATION FORM

TO           : •
ATTENTION    : •
PHONE        : •             FAX: •          _________________________
ERC EVENT START : •                         |PRIOR PERIOD REVISION:   |
ERC EVENT END:    •                         |             ______(Y/N) |
                                            |DATE: ___________________|
STATION NAME:  •                            |_________________________|
STATION NO  :  •     STATION MN: •      _____________________________
                                       |CSO ALLOCATION AUTHORIZATION:|
                                       |NAME :_______________________|
                                       |TITLE:_______________________|
                                       |SIGNATURE:___________________|
TOTAL STATION ESTIMATED EVENT ENGY (GJ):   •
EVENT PRICE OF $•

     CUSTOMER                                 ESTIMATED EVENT   FINAL EVENT
 NO  MN ACCT NAME                                      ENERGY       ENERGY

•     •   •    •                                •              ________



FINAL EVENT ENERGY TOTALS MUST EQUAL THE STATION TOTALS        ________

*** THIS ALLOCATION IS FOR THE EMERGENCY RESPONSE COMPENSATION PROCEDURE.


REPLY TO FAX #:  •

FOR FURTHER INFORMATION CALL : •
                    PHONE NO : •

REPLY NO LATER THAN : •
```

Schedule “B”

Plant Survey

Station Name	Station Number	Minimum Turndown (e3m3/day)	Initial Response Time (hrs.)	Flow After Initial Response (e^3m^3/day)	Remaining Response Time (hrs.)	Flow After Remaining Response (e^3m^3/day)	Contactable Hours of Operation	Plant Phone #	Plant 24 Hour Phone #	Plant Fax #	Notification Pager #

SURVEY DEFINITIONS

Contactable Hours of Operation - please choose one of the following:

A =	24 hrs. 7 days/week	D =	Visit once per calendar day
B =	8 hrs. 7 days/week	E =	Visit once per business day
C =	8 hrs. 5 days/week	F =	Visit once per 2 business days

Flow After Initial Response = the Flow specified by CSO in this Plant Survey that the CSO will reduce to within the Initial Response Time.

Flow After Remaining Response = the Flow in excess of Flow After Initial Response specified by CSO in this Plant Survey that the CSO will reduce to within the Remaining Response Time.

Initial Response Time = the length of time, up to a maximum of two hours, specified by CSO in this Plant Survey that the CSO is able to reduce Flow to its' Flow After Initial Response when requested to do so by Company regardless of the day or time of day.

Remaining Response Time = the length of time greater than two hours, specified by the CSO in this Plant Survey that the CSO is able to reduce Flow to its' Flow After Remaining Response when requested to do so by Company regardless of the day or time of day.

Minimum Turndown = the minimum Flow of gas a Plant is required to process in order to maintain continuous operations.

CSO SIGNATURE: ___________________________

DATE: _____________________________________

APPENDIX 3B: ENERGY CONVERSION TARIFF CHANGES (BLACKLINED)

Summary of Amendments

1. Rate Schedule FT-D, Firm Transportation – Delivery

(i) Amended paragraph 4.3 [Aggregate of Customer's Over-Run Gas Charges] – changed from "volume" to "quantity."

(ii) Amended paragraph 4.6 [Allocation of Gas Delivered] – changed from "volume" to "quantity."

(iii) Amended subparagraph 5(b) of Service Agreement – changed from "volume" to "quantity."

(iv) Amended paragraph 6 of Service Agreement – changed from "volume" to "quantity."

(v) Amended Schedule of Service – changed Export Delivery Contract Demand from "10^3m^3/d" to "GJ/d."

2. Rate Schedule FT-DW, Firm Transportation – Delivery Winter

(i) Amended paragraph 4.3 [Aggregate of Customer's Over-Run Gas Charges] – changed from "volume" to "quantity."

(ii) Amended paragraph 4.6 [Allocation of Gas Delivered] – changed from "volume" to "quantity."

(iii) Amended subparagraph 5(b) of Service Agreement – changed from "volume" to "quantity."

(iv) Amended paragraph 6 of Service Agreement – changed from "volume" to "quantity."

(v) Amended Schedule of Service – changed Export Delivery Contract Demand from "10^3m^3/d" to "GJ/d."

3. Rate Schedule STFT, Short Term Firm Transportation – Delivery

(i) Amended paragraph 4.4 [The Bid Process and Allocation of STFT Service] – changed from "volumes" to "quantities."

(ii) Amended paragraph 5.1 [STFT Bid Price] – changed from "Thousand Cubic Meters" to "gigaJoules."

(iii) Amended subparagraphs 6.1(a) and (b) [Allocation of Available STFT Capacity] – changed from "Volume Multiplier" to "Quantity Multiplier."

(iv) Amended paragraph 7.2 [Aggregate of Customer's Over-Run Gas Charges] – changed from "volume" to "quantity."

(v) Amended paragraph 7.4 [Allocation of Gas Delivered] – changed from "volume" to "quantity."

(vi) Amended subparagraph 5(b) of Service Agreement – changed from "volume" to "quantity."

(vii) Amended paragraph 6 of Service Agreement – changed from "volume" to "quantity."

(viii) Amended Schedule of Service – changed Maximum STFT Capacity, Minimum STFT Capacity, Bid Price and Allocated STFT Capacity from "10^3m^3" to "GJ."

4. Rate Schedule LRS, Load Retention Service

(i) Amended paragraph 4.2 [Determination of LRS Billing Adjustment] – added "the volumetric equivalent" to the FT-D Demand Rate.

(ii) Amended subparagraph 4.2.2(ii) [Calculation of Amount Charged in Respect of the Eligible LRS Contract Demand using the FT-R Demand Rate(s) and the FT-D Demand Rate] – added "the volumetric equivalent" to the FT-D Demand Rate.

5. Rate Schedule LRS-2, Load Retention Service - 2

(i) Amended subparagraph 4.1(ii) [Determination of Monthly Charge] – added "volumetric" to the daily equivalent to the FT-D Demand Rate.

(ii) Amended subparagraph 4.4.2 [Allocation of Gas Delivered] – changed from "volume" to "quantity."

(iii) Amended subparagraph 4.4.2 (v) [Allocation of Gas Delivered] – changed from "volumes" to "quantities."

(iv) Amended paragraph 11.1 [Gas Used] – changed from "volumes" to "quantities."

(v) Amended subparagraph 5(b) of Service Agreement – changed from "volume" to "quantity."

(vi) Amended paragraph 6 of Service Agreement – changed from "volume" to "quantity."

6. Rate Schedule LRS-3, Load Retention Service - 3

(i) Amended subparagraph 4.2(iii) [Determination of LRS-3 Billing Adjustment] – added "the volumetric equivalent" to the FT-D Demand Rate.

(ii) Amended subparagraph 4.2.3(ii) [Determination of Customer's Monthly Charge in respect of the Eligible LRS-3 Contract Demands using the FT-R Demand Rate(s) and the FT-D Demand Rate] – added "the volumetric equivalent" to the FT-D Demand Rate.

7. Rate Schedule IT-D, Interruptible Transportation – Delivery

(i) Amended paragraph 4.1 [Aggregate of Customer's Monthly Charge] – changed from "volume" to "quantity."

(ii) Amended paragraph 4.4 [Allocation of Gas Delivered] – changed from "volume" to "quantity."

(iii) Amended subparagraph 3(a) of Service Agreement – changed from "volume" to "quantity."

(iv) Amended paragraph 5(b) of Service Agreement – changed from "volumes" to "quantities."

8. Rate Schedule IT-S, Interruptible – Access to Storage

(i) Amended paragraph 4.2 [Allocation of Gas Delivered] – changed from "volume" to "quantity."

(ii) Amended subparagraph 5.2(ii) [Storage Information] – changed from "volume" to "quantity."

(iii) Amended paragraph 5(b) of Service Agreement – changed from "volumes" to "quantities."

9. General Terms and Conditions

(i) Definitions

(a) Amended paragraph 1.11 [Common Stream Operator] – changed from "Measured Volume and Total Energy" to "Total Quantity."

- (b) Amended paragraph 1.20 [Customer's Inventory] – changed from "volume" of gas to "quantity" of gas.
- (c) Amended paragraph 1.30 [Export Delivery Contract Demand] – changed from "volume" of gas to "quantity" of gas and added "expressed in GJ or as converted to GJ pursuant to paragraph 15.12."
- (d) Amended paragraph 1.48 [Gas Lost] – changed from "volume" of gas to "quantity" of gas.
- (e) Amended paragraph 1.49 [Gas Used] – changed from "volume" of gas to "quantity" of gas.
- (f) Added new paragraph 1.51 [GJ] – "shall mean gigajoule or one billion joules."
- (g) Added new paragraph 1.55 [J or joule] – "shall mean the base unit for energy as defined by the International System of Units (SI)."
- (h) Amended paragraph 1.57 [Line Pack Gas] – changed from "volume" of gas to "quantity" of gas.
- (i) Added new paragraph 1.68 [MJ] – "shall mean megajoule or one million joules."
- (j) Amended paragraph 1.73 [Over-Run Gas] – changed from "volume" of gas to "quantity" of gas.
- (k) Added new paragraph 1.83 [Quantity Multiplier] – renamed definition of [Volume Multiplier].
- (l) Added new paragraph 1.104 [TJ] – "shall mean terajoule or one trillion joules."
- (m) Deleted paragraph 1.102 [Volume Multiplier] – renamed definition to [Quantity Multiplier].

(ii) Amended paragraph 4.1 [Method of Measurement] – amended to include energy.

(iii) Amended paragraph 4.2 [Unit of Measurement]

- (a) Added new subparagraph 4.2.2 – "The unit of energy for purposes of measurement hereunder shall be a GJ."

(iv) Amended paragraph 8.1(a) [Company's Gas Requirements] – changed from "volume" of gas to "quantity" of gas and added clarification that Company's Gas Requirements are taken from all Customers "at Receipt Points."

(v) Amended subparagraph 8.1(b) [Company's Gas Requirements] – changed from "volume" of gas to "quantity" of gas and added clarification that arrangement to take and pay for a quantity is with Customers "at Receipt Points."

(vi) Amended paragraph 8.2 [Allocation of Gas Taken] – changed from "volume" of gas to "quantity" of gas.

(vii) Amended subparagraph 9.1(a) [Company's Delivery Obligation] – changed from "volume" of gas to "quantity" of gas.

(viii) Amended subparagraph 9.1(b) [Company's Delivery Obligation] – changed from "volume" of gas to "quantity" of gas.

(ix) Amended paragraph 9.2 [Variance] – changed from "volume" of gas to "quantity" of gas.

(x) Amended paragraph 14.2 [Additional Information] – changed from “volumes” to “quantities.”

(xi) Added new paragraph 15.12 [Conversion of Service Agreements to Energy Units]

(a) Added subparagraph 15.12(a) – specifies that all new FT-D, FT-DW and STFT Service Agreements will be signed in energy commencing on November 1, 2006.

(b) Added subparagraph 15.12(b) – outlines how Export Delivery Contract Demands will be converted to energy at each Export Delivery Point for all existing FT-D, FT-DW and STFT Service Agreements commencing on November 1, 2006.

10. Appendix D – Terms and Conditions Respecting Customer’s Inventories and Related Matters

(i) Definitions

(a) Amended paragraph 1.2 [Balanced Zone] – changed from “Total Energy” to “Total Quantity.”

(b) Deleted paragraph 1.4 [Measured Volume].

(c) Amended paragraph 1.5 [Pipeline Tolerance Level] – changed from “volume” of gas to “quantity” of gas.

(d) Amended paragraph 1.6 [Total Quantity] – changed from “Total Energy” to “Total Quantity.”

(e) Deleted paragraph 1.7 [TJ] – moved definition to the General Terms and Conditions.

(ii) Amended paragraph 3.2 [Determination and Allocation of Flows] – changed from “Measured Volumes and Total Energy” to “Total Quantity.”

(iii) Amended paragraph 3.3 [Determination and Allocation of Flows] – changed from “Measured Volumes and Total Energy” to “Total Quantity” and added “allocation” to determination of Total Quantity.

(iv) Amended paragraph 5.1 [Discretion] – changed from “volume” to “quantity.”

(v) Amended paragraph 7.1 [NIT Only Customers] – changed from “volume” to “quantity” and “Total Energy” to “Total Quantity.”

(vi) Amended paragraph 8.1 [Administration of Customer’s Inventories at Month End] – changed from “Total Energy” to “Total Quantity.”

11. Appendix G – Terms and Conditions Respecting Emergency Response Compensation

(i) Deleted Definition 1.22 [GJ] – definition appears in the General Terms and Conditions.

4.3 Aggregate of Customer's Over-Run Gas Charges

The aggregate of Customer's charges for Over-Run Gas in a Billing Month for Service under Rate Schedule FT-D shall be equal to the sum of the monthly charges for Over-Run Gas for each Export Delivery Point at which Customer is entitled to Service under Rate Schedule FT-D, determined as follows:

MOC = ~~V~~Q x Z

Where:

"MOC" = the monthly charge for Over-Run Gas at the Export Delivery Point;

"~~V~~Q" = total ~~volume~~ quantity of gas allocated to Customer by Company as Over-run Gas in accordance with paragraph 4.6 for Service under all Rate Schedules at such Export Delivery Point for the month preceding such Billing Month;

"Z" = the IT-D Rate at such Export Delivery Point.

4.4 The calculation of Customer's charge for Over-Run Gas in paragraph 4.3 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

4.5 Aggregate Charge For Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 4.1, 4.2, and 4.3.

4.6 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have

been nominated, the aggregate ~~volume~~ quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to Service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D;

(iv) fourthly to Service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to Customer under Rate Schedule IT-D at such Export Delivery Point. If Customer is not entitled to service under Rate Schedule IT-D at such Export Delivery Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 4.3.

5.0 TERM OF SERVICE

5.1 Term of a Schedule of Service

If, in the provision of new Service, Company determines that:

(i) no new Facilities are required that are directly attributable (generally mainline facilities) to Customer's request for such Service, the term of the Schedule of

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule FT-D including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating ~~volumes~~ quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas ~~volume~~ quantity actually received or the aggregate gas ~~volume~~ quantity actually delivered at the Facilities is different than forecast.

SCHEDULE OF SERVICE
RATE SCHEDULE FT-D

CUSTOMER: •

Schedule of Service Number	Export Delivery Point Number and Name	Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Export Delivery Contract Demand ~~10^3m^3~~GJ/d	Additional Conditions
•	• •	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

4.3 Aggregate of Customer's Over-Run Gas Charges

The aggregate of Customer's charges for Over-Run Gas in a Billing Month for Service under Rate Schedule FT-DW shall be equal to the sum of the monthly charges for Over-Run Gas for each Export Delivery Point at which Customer is entitled to Service under Rate Schedule FT-DW, determined as follows:

MOC = ~~V~~Q x Z

Where:

"MOC" = the monthly charge for Over-Run Gas at the Export Delivery Point;

"~~V~~Q" = total ~~volume~~ quantity of gas allocated to Customer by Company as Over-run Gas in accordance with paragraph 4.6 for Service under all Rate Schedules at such Export Delivery Point for the month preceding such Billing Month;

"Z" = the IT-D Rate at such Export Delivery Point.

4.4 The calculation of Customer's charge for Over-Run Gas in paragraph 4.3 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

4.5 Aggregate Charge For Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 4.1, 4.2, and 4.3.

4.6 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have

been nominated, the aggregate ~~volume~~ quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D;

(iv) fourthly to Service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to Customer under Rate Schedule IT-D at such Export Delivery Point. If Customer is not entitled to service under Rate Schedule IT-D at such Export Delivery Point, gas shall be allocated as Over-Run Gas and charged in accordance with paragraph 4.3.

5.0 TERM OF SERVICE

5.1 Initial Term of a Schedule of Service

The initial term for any Schedule of Service for Service under Rate Schedule FT-DW shall be four (4) consecutive Winter Seasons.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule FT-DW including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating ~~volumes~~ quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas ~~volume~~ quantity actually received or the aggregate gas ~~volume~~ quantity actually delivered at the Facilities is different than forecast.

SCHEDULE OF SERVICE
RATE SCHEDULE FT-DW

CUSTOMER: •

Schedule of Service Number	Export Delivery Point Number and Name	Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Export Delivery Contract Demand ~~10^3m^3~~GJ/d	Additional Conditions
•	• •	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ____________________	Per : ____________________
Per: ____________________	Per : ____________________

of the Schedule of Service attached as Exhibit "A" to the Service Agreement (the "Customer Bid"), to Company through Company's electronic bulletin board, or if not available, by fax.

4.3 Customer Bids once received by Company shall constitute an irrevocable binding offer on the part of Customer, which cannot be withdrawn. Company will determine, in accordance with article 6.0, which Customer Bids are accepted by Company and shall notify Customer through Company's electronic bulletin board, or if not available, by fax which, if any, of Customer's bids have been accepted.

4.4 Customer shall submit a separate Customer Bid for each separate combination of Export Delivery Point, STFT Bid Price, as defined in article 5.0, and Block Period. Customer shall not submit a Customer Bid for ~~volumes~~ quantities greater than the available STFT Capacity being offered at each Export Delivery Point. Customer Bids which are not made in accordance with the terms of this Rate Schedule shall be rejected.

5.0 STFT BID PRICE

5.1 Each Customer Bid shall set out the bid price (the "STFT Bid Price") expressed in Canadian dollars and cents per ~~Thousand Cubic Meters~~gigaJoules per Month ($CDN/~~$10^3$ m^3~~ GJ/Month). The STFT Bid Price shall not be less than 135% of the applicable FT-D Demand Rate listed in the Table of Rates Tolls and Charges in effect on the day the Company receives the Customer Bid. In the event there is an increase or decrease to the FT-D Demand Rate after the Customer has submitted its Customer Bid, it is expressly agreed and understood that the STFT Bid Price shall be deemed to be increased or decreased as the case may be by an amount that maintains the same ratio of the STFT Bid Price to the FT-D Demand Rate as existed on the date Customer submitted its Customer Bid to Company.

6.0 ALLOCATION OF AVAILABLE STFT CAPACITY

6.1 Each Month upon receipt of Customer Bids, Company shall determine which Customer Bids are accepted and shall allocate STFT Capacity among Customers whose submitted Customer Bids were accepted by Company in the following manner:

(a) all Customer Bids for the particular Month, received by Company for a particular Export Delivery Point shall be ranked in descending order from the greatest to least ~~volume~~ quantity multiplier as determined in accordance with the following formula (the "~~Volume~~ Quantity Multiplier"):

~~V~~QM = A x B

Where:

"~~V~~QM" = the Customer's ~~Volume~~ Quantity Multiplier;

"A" = the STFT Bid Price for a particular Customer Bid; and

"B" = the number of months in the Block Period for a particular Customer Bid.

(b) Company shall allocate available STFT Capacity at each Export Delivery Point to Customers submitting Customer Bids in descending order starting with the Customer Bids having the highest ranking, determined based upon the ~~Volume~~ Quantity Multiplier until the available STFT Capacity has been allocated.

(c) In the event two (2) or more Customer Bids have the same ranking, determined in the manner provided for in subparagraph 6.1(a), then such Customer Bids will be ranked in descending order with the higher ranking being assigned to the Customer Bid which contains the highest STFT Bid Price for the shortest Block Period; provided however, if the STFT Bid Price and Block Period are identical and the available STFT Capacity is not sufficient to provide Service for the

7.2 Aggregate of Customer's Over-Run Gas Charges

In the event that Company determines for a Billing Month that Company has delivered to Customer, in the month preceding such Billing Month, a ~~volume~~ quantity of gas at any Export Delivery Point in excess of the aggregate of the sum of:

(a) the products obtained when the STFT Capacity allocated to such Customer in respect of such Export Delivery Point is multiplied by the number of Days in the month preceding such Billing Month; and

(b) the sum of the products obtained when each of the Export Delivery Contract Demand in effect for Customer in respect of Rate Schedule FT-D in the month preceding such Billing Month is multiplied by the number of Days in such month that the Export Delivery Contract Demand was in effect,

then Customer shall pay to Company an amount equal to the product of such excess ~~volume~~ quantity and the applicable IT-D Rate.

7.3 Aggregate Charge for Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 7.1 and 7.2.

7.4 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate ~~volume~~ quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule STFT.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule STFT including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating ~~volumes~~ quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas ~~volume~~ quantity actually received or the aggregate gas ~~volume~~ quantity actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule STFT, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

•

•

•

Attention: •

Fax: •

Company:

•

•

•

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not

NOVA Gas Transmission Ltd.

SCHEDULE OF SERVICE
RATE SCHEDULE STFT

CUSTOMER: •

•
•
•

ATTENTION: •
PHONE: • FAX: •

Schedule of Service Number	**Export Delivery Point Number and Name**	**Maximum STFT Capacity ~~10^3m^3~~GJ/d**	**Minimum STFT Capacity ~~10^3m^3~~GJ/d**	**Bid Price $/~~$10^3m^3$~~GJ~~/~~ Month**	**Block Period**	**Billing Commencement**	**Service Termination Date**	**Allocated STFT Capacity ~~10^3m^3~~GJ/d**
•	• •	•	•	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

"B"	=	the number of days in such Billing Month that Customer was entitled to such LRS Contract Demand under such Schedule of Service; and
"C"	=	the number of days in such Billing Month.

4.2 Determination of LRS Billing Adjustment

Customer's monthly LRS Billing Adjustment for a Billing Month for Service under Rate Schedule LRS shall be calculated by the application of the following four steps:

(i) determination of the Eligible LRS Contract Demand as described in subparagraph 4.2.1;

(ii) calculation of the amount that has been charged in respect of the Eligible LRS Contract Demand using the applicable FT-R Demand Rates and the volumetric equivalent of the FT-D Demand Rate as described in subparagraph 4.2.2;

(iii) calculation of the amount that should be charged in respect of Service under Rate Schedule LRS by applying the Effective LRS Rate to the Eligible LRS Contract Demand as described in subparagraph 4.2.3; and

(iv) determination of the LRS Billing Adjustment that will be applied to Customer's bill, as described in subparagraph 4.2.4, by determining the difference between the amounts calculated in steps (ii) and (iii).

4.2.1. Determination of Eligible LRS Contract Demand

Eligible LRS Contract Demand will be determined based on the information provided by Customer by way of an Officer's Certificate in such form as Company may prescribe from time to time. Eligibility is achieved only when Customer has provided a valid Officer's Certificate which satisfies Company that the requirements under Rate Schedule

4.2.2. Calculation of Amount Charged in respect of the Eligible LRS Contract Demands using the FT-R Demand Rate(s) and the FT-D Demand Rate

After having determined the Eligible LRS Contract Demand, Company will calculate the amount that has been charged with respect to paragraph 4.1 of this Rate Schedule LRS. The amount that has been charged is the sum of:

(i) for all of Customer's Receipt Points identified in Appendix "1" the aggregate of the product of the FT-R Demand Rate and Price Point "A" and the Eligible LRS Contract Demand for each Receipt Point (the "Receipt Demand Charge"); and

(ii) the volumetric equivalent of the FT-D Demand Rate multiplied by the Eligible LRS Contract Demand (the "Delivery Demand Charge").

4.2.3. Calculation of the Amounts To Be Charged for LRS Service

The amount to be paid for Service under Rate Schedule LRS (the "LRS Charge") will be the product of the Effective LRS Rate and the Eligible LRS Contract Demand. The Effective LRS Rate is included in the Table of Rates, Tolls and Charges of this Tariff.

The Effective LRS Rate commences on January 1, 1998 and escalates at the rate of two (2) per cent per annum starting January 1, 1999.

4.2.4. Determination of LRS Billing Adjustment

The LRS Billing Adjustment will be calculated as follows:

(i) Company will calculate the sum of the Receipt Demand Charge and the Delivery Demand Charge; and

(ii) Company will calculate the difference between the LRS Charge and the amount calculated in accordance with subparagraph 4.2.4 (i).

4.0 CHARGE FOR SERVICE

4.1 Determination of Monthly Charge

LRS-2 Customer will be charged and shall pay a monthly amount (the "Monthly Charge") for a Billing Month equal to the sum for all days of such month of the following amounts:

(i) the daily equivalent of the FT-R Demand Rate at the Coleman Receipt Point multiplied by Price Point "A" (as defined in Rate Schedule FT-R) multiplied by the Service Entitlement for the day in the Billing Month; and

(ii) the daily volumetric equivalent of the FT-D Demand Rate at the A/BC Export Delivery Point multiplied by the Service Entitlement for the day in the Billing Month.

4.2 Determination of the LRS-2 Adjustment

The LRS-2 Adjustment for a Billing Month shall be equal to the Monthly Charge for such Billing Month less $50,000. The LRS-2 Adjustment shall then be applied against LRS-2 Customer's invoice issued in the second month following the Billing Month.

4.3 Determination of Eligible LRS-2 Volume

4.3.1 Officer's Certificate

LRS-2 Customer shall provide Company with a valid officer's certificate setting out the Eligible LRS-2 Volume for each day in a Billing Month, in such form as Company may prescribe from time to time (the "Officer's Certificate") on or before the last day of the month following the Billing Month, for purposes of determining the Eligible LRS-2 Volume.

(iii) thirdly to service to LRS-2 Customer under Rate Schedule FT-RN to a maximum of such Customer's Receipt Contract Demand for such Coleman Receipt Point under Rate Schedule FT-RN; and

(iv) fourthly to service to LRS-2 Customer under Rate Schedule IT-R for such Coleman Receipt Point. If LRS-2 Customer is not entitled to service under Rate Schedule IT-R at such Coleman Receipt Point, LRS-2 Customer shall be deemed to have been entitled to such service for the purposes of this subparagraph 4.4.1 (iii) and shall pay to Company an amount determined under article 4.0 of Rate Schedule IT-R for the volumes allocated under this subparagraph 4.4.1 (iii).

4.4.2 Allocation of Gas Delivered

Notwithstanding any other provision of Rate Schedule LRS-2, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate daily ~~volume~~ quantity of gas delivered to LRS-2 Customer at the A/BC Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to Service to LRS-2 Customer under Rate Schedule LRS-2 to a maximum of Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to LRS-2 Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract demand for such A/BC Export Delivery Point under such Rate Schedule FT-D;

(iv) forthly to service to LRS-2 Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract demand for such A/BC Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to service to LRS-2 Customer under Rate Schedule IT-D for such A/BC Export Delivery Point. If LRS-2 Customer is not entitled to service under Rate Schedule IT-D at such A/BC Export Delivery Point, LRS-2 Customer shall be deemed to have been entitled to such service for the purposes of this subparagraph 4.4.2 (v) and shall pay to Company an amount determined under article 4.0 of Rate Schedule IT-D for the ~~volumes~~ quantities allocated under this subparagraph 4.4.2 (v).

5.0 TERM OF SERVICE AGREEMENT

5.1 The term of the Service Agreement under Rate Schedule LRS-2 shall commence on the effective date of the Board's Order approving Service under Rate Schedule LRS-2 and shall expire on October 31, 2013, provided however nothing herein shall relieve LRS-2 Customer or Company from any obligation which arose or accrued on or prior to October 31, 2013; and further provided that the LRS-2 Adjustments for the last two Billing Months of the Service Agreement under Rate Schedule LRS-2 shall be paid by the Company to LRS-2 Customer on or before December 31, 2013.

6.0 TRANSFER OF LRS-2 SERVICE

6.1 LRS-2 Customer shall not be entitled to transfer all or any portion of Service under Rate Schedule LRS-2 to any other Receipt Point or Delivery Point. LRS-2 Customer shall not be entitled to convert Service under Rate Schedule LRS-2 to any other service under any other Rate Schedule.

7.0 TERM SWAP OF LRS-2 SERVICE

7.1 LRS-2 Customer entitled to receive Service under Rate Schedule LRS-2 shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate

11.0 GAS USED

11.1 In respect of ~~volumes~~ quantities that are transported utilizing Service under Rate Schedule LRS-2, LRS-2 Customer shall not be charged for nor shall any deduction be made for that portion of Gas Used which is attributable to gas used for compression. In respect of ~~volumes~~ quantities that are transported utilizing Service under Rate Schedule LRS-2, Company shall also not charge LRS-2 Customer nor shall it make any deduction for that portion of Gas Used which is attributable to gas used for heating and pipeline losses until Company's systems are capable of separating Gas Used into the following components:

(i) gas used for compression;

(ii) gas used for heating; and

(iii) pipeline losses.

12.0 AUDIT RIGHTS

12.1 Company shall be entitled to audit, at its sole discretion and expense, at any time it determines necessary, any and all documents related to any Officer's Certificate and the contents thereof, in order to verify the accuracy of such Officer's Certificate, provided that any such audit shall be carried out within 24 months of the month to which such Officer's Certificate relates.

13.0 PRIORITY DURING INTERRUPTIONS

13.1 For the purposes of paragraph 11.4 of the General Terms and Conditions of the Tariff, Service under Rate Schedule LRS-2 shall have equal priority to service under Rate Schedule FT-R, FT-RN, FT-P, FT-A, FT-X, STFT, LRS, LRS-3, FT-D and FT-DW as the case may be.

4. Customer agrees to pay to Company each Billing Month, for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule LRS-2.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to Rate Schedule LRS-2 including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point or downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating ~~volumes~~ quantities of gas received or delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided; and

(c) provide the Officer's Certificate as defined in 4.3.1 of Rate Schedule LRS-2. If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas ~~volume~~ quantity actually received or the aggregate gas ~~volume~~ quantity actually delivered at the Facilities is different than forecast.

7. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule LRS-2, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

•

•

•

Attention: •

Fax: •

Company:

•

•

•

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice

"B"	=	the number of days in such Billing Month that Customer was entitled to such LRS-3 Contract Demand under such Schedule of Service; and
"C"	=	the number of days in such Billing Month.

4.2 Determination of LRS-3 Billing Adjustment

Customer's monthly billing adjustment for a Billing Month for Service under Rate Schedule LRS-3 (the "LRS-3 Billing Adjustment") shall be calculated as follows:

(i) determine the Eligible LRS-3 Contract Demand as described in subparagraph 4.2.1;

(ii) determine the amount that should be charged in respect of Service under Rate Schedule LRS-3 by applying the LRS-3 Rate to the Eligible LRS-3 Contract Demand as described in subparagraph 4.2.2;

(iii) determine the amount that has been charged in respect of the Eligible LRS-3 Contract Demand using the applicable FT-R Demand Rates and the volumetric equivalent of the FT-D Demand Rate as described in subparagraph 4.2.3;

(iv) during the Initial LRS-3 Term, determine the amount that should be adjusted in respect of charges for Service under Rate Schedule IT-R and Over-run Gas at the LRS-3 Receipt Points as described in subparagraph 4.2.4; and

(v) determine the LRS-3 Billing Adjustment that will be applied to Customer's invoice, as described in subparagraph 4.2.5.

4.2.1. Determination of Eligible LRS-3 Contract Demand

Eligible LRS-3 contract demand for each LRS-3 Receipt Point (the "Eligible LRS-3 Contract Demand") shall be determined by Company as follows:

During the Secondary LRS-3 Term, IT shall be deemed to be zero.

4.2.2. Determination of Amounts To Be Charged in respect of Eligible LRS-3 Contract Demand

The amount to be paid for Service under Rate Schedule LRS-3 (the "LRS-3 Charge") will be the product of the LRS-3 Demand Rate and the aggregate Eligible LRS-3 Contract Demand.

4.2.3. Determination of Customer's Monthly Charge in respect of the Eligible LRS-3 Contract Demands using the FT-R Demand Rate(s) and the FT-D Demand Rate

Company will calculate an amount that is deemed to be the amount charged in the month preceding the Billing Month with respect to the Eligible LRS-3 Contract Demand determined in subparagraph 4.2.1. Such deemed amount shall be the sum of:

(i) for all of Customer's LRS-3 Receipt Points, the aggregate of the product of the FT-R Demand Rate, the applicable Price Point and the Eligible LRS-3 Contract Demand for each LRS-3 Receipt Point (the "LRS-3 Receipt Demand Charge"); and

(ii) the volumetric equivalent of the FT-D Demand Rate multiplied by the aggregate Eligible LRS-3 Contract Demand (the "LRS-3 Delivery Demand Charge").

4.2.4. Determination of Adjustments with respect to IT-R and Over-run Gas Charges

During the Initial LRS-3 Term, Company will determine a monthly commodity charge adjustment for a Billing Month in respect of charges for Service under Rate Schedule IT-R and Over-run Gas at the LRS-3 Receipt Points, determined as follows:

$$MA = A - [(B - C) \times D]$$

Where:

"MA" = the monthly commodity charge adjustment applicable to such Billing Month;

4.0 CHARGE FOR SERVICE

4.1 Aggregate of Customer's Monthly Charge

The aggregate of Customer's monthly charges for a Billing Month for Service under Rate Schedule IT-D shall be equal to the sum of the monthly charges calculated for each of Customer's Export Delivery Points under Rate Schedule IT-D determined as follows:

MC = A x B

Where:

"MC" = the monthly charge applicable to such Export Delivery Point;

"A" = the IT-D Rate at such Export Delivery Point; and

"B" = the sum of the ~~volume~~ quantity of gas delivered by Company to such Customer at such Export Delivery Point under Rate Schedule IT-D in the month preceding such Billing Month.

4.2 Aggregate of Customer's Surcharges

The aggregate of Customer's Surcharges for a Billing Month shall be equal to the sum of all Surcharges set forth in the Table of Rates, Tolls and Charges applicable to each of Customer's Export Delivery Points under Rate Schedule IT-D.

4.3 Aggregate Charge For Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 4.1 and 4.2.

4.4 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have

been nominated, the aggregate ~~volume~~ quantity of gas delivered to Customer at an Export Delivery Point shall be allocated for billing purposes as follows:

(i) first to service to Customer under Rate Schedule LRS-2 to a maximum of such Eligible LRS-2 Volumes for the A/BC Export Delivery Point under such Rate Schedule LRS-2;

(ii) secondly to service to Customer under Rate Schedule STFT to a maximum of such Customer's allocated STFT Capacity for such Export Delivery Point under such Rate Schedule STFT;

(iii) thirdly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-D;

(iv) fourthly to service to Customer under Rate Schedule FT-DW to a maximum of such Customer's Export Delivery Contract Demand for such Export Delivery Point under such Rate Schedule FT-DW; and

(v) fifthly to Service to Customer under Rate Schedule IT-D.

5.0 TERM OF SERVICE

5.1 Term of Service at an Export Delivery Point

The term for any Schedule of Service for Service under Rate Schedule IT-D at each Export Delivery Point shall be the term requested by Customer, provided that the term is a minimum of one (1) month and terminates on the last day of a Gas Year.

5.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service under Rate Schedule IT-D.

SERVICE AGREEMENT

RATE SCHEDULE IT-D

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta ("Company")

- and -

•, a body corporate having an office in •, • ("Customer")

IN CONSIDERATION of the premises and the covenants and agreements in this Service Agreement, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule IT-D in accordance with the following procedure:

(a) subject to the provisions of this paragraph 3, upon execution and delivery of this Service Agreement Customer shall be entitled to Service at any Export Delivery Point described in the Schedule of Service respecting Rate Schedule IT-D, provided however that Customer may not with respect to any Service at any Export Delivery Point described in such Schedule of Service request Company to deliver a ~~volume~~ quantity of gas in excess of the capacity of the facilities (as determined by Company) downstream of such Export Delivery Point;

respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating ~~volumes~~ quantities of gas delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule IT-D, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

-
-
-

Attention: •

Fax: •

(i) If paragraph 3.1(i) applies, then the volume of gas received shall be allocated only to Service to Customer under Rate Schedule IT-S; or

(ii) If paragraph 3.1(ii) applies, then the volume of gas received shall be allocated:

(a) first to service to Customer under Rate Schedules LRS and LRS-3 to a maximum of such Customer's LRS Contract Demand for such Receipt Point under such Rate Schedule LRS and to a maximum of such Customer's LRS-3 Contract Demand for such Receipt Point under such Rate Schedule LRS-3;

(b) secondly to service to Customer under Rate Schedule FT-R to a maximum of such Customer's Receipt Contract Demand for such Storage Receipt Point under such Rate Schedule FT-R;

(c) thirdly to service to Customer under Rate Schedule FT-RN to a maximum of such Customer's Receipt Contract Demand for such Storage Receipt Point under such Rate Schedule FT-RN;

(d) fourth to service to Customer under Rate Schedule IT-R at such Storage Receipt Point. If Customer is not entitled to service under Rate Schedule IT-R at such Storage Receipt Point, then Customer shall pay the IT-R Rate at such Storage Receipt Point in respect of such volume of gas allocated to it hereunder.

4.2 Allocation of Gas Delivered

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of this Tariff, and without regard to how gas may have been nominated, the aggregate ~~volume~~ quantity of gas delivered at a Storage Delivery Point for Customer, shall be allocated as follows:

(i) If paragraph 3.1(i) applies, then the ~~volume~~ quantity of gas delivered shall be allocated only to Service to Customer under Rate Schedule IT-S; or

(ii) If paragraph 3.1(iii) applies, then the ~~volume~~ quantity of gas delivered shall be allocated:

(a) first to service to Customer under Rate Schedule FT-A at such Storage Delivery Point, if Company is satisfied that the ~~volume~~ quantity of gas delivered by Company at such Storage Delivery Point is not to be removed from Alberta. If Customer is not entitled to service under Rate Schedule FT-A at such Storage Delivery Point, then Customer shall pay the FT-A Rate in respect of such ~~volume~~ quantity of gas allocated to it hereunder;

(b) secondly to service to Customer under Rate Schedule FT-D to a maximum of such Customer's Export Delivery Contract Demand for such Storage Delivery Point under such Rate Schedule FT-D; and

(c) thirdly, under all other circumstances other than the ones set out in paragraphs 4.2(ii)(a) and 4.2(ii)(b), to service to Customer under Rate Schedule IT-D at such Storage Delivery Point. If Customer is not entitled to service under Rate Schedule IT-D at such Storage Delivery Point, regardless of whether of not such Storage Delivery Point is an Export Delivery Point, then Customer shall pay the IT-D Rate in respect of such ~~volume~~ quantity of gas allocated to it hereunder.

5.0 STORAGE INFORMATION

5.1 Customer undertakes to cause the operator of every gas storage facility connected to the Storage Receipt Point and the Storage Delivery Point to provide to Company, when requested by the Company, the following information:

(i) the cumulative total of the volume of gas delivered to the Storage Delivery Point for Customer by Company; and

(ii) the cumulative total of the volume of gas received at the Storage Receipt Point by Company for Customer.

5.2 If the operator of a gas storage facility fails to provide Company with the information requested with respect to any month within the time provided by Company for a response to Company's request:

(i) the gas received at the Storage Receipt Point for Customer for such month shall be deemed to have been received for Customer at the Storage Receipt Point under Rate Schedule IT-R and Customer shall pay the IT-R Rate applicable to such Storage Receipt Point in respect of such volume; and

(ii) the gas delivered at the Storage Delivery Point for Customer for such month shall be deemed to have been delivered by Customer at the Storage Delivery Point under Rate Schedule IT-D and Customer shall pay the IT-D Rate in respect to such ~~volume~~ quantity regardless of whether or not such Storage Delivery Point is an Export Delivery Point.

6.0 TERM OF SERVICE

6.1 Term of Service at a Storage Receipt Point and Delivery Point

The term for any Schedule of Service for Service under Rate Schedule IT-S at each Storage Receipt Point and at each Storage Delivery Point shall be the term requested by Customer, provided that the term is a minimum of one (1) month and terminates on the last day of a Gas Year.

Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point or downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating ~~volumes~~ quantities of gas received or delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule IT-S, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

1.9 "CO_2 Volume" shall mean the portion of the total excess volume of carbon dioxide allocated by a CSO to a Customer at a particular Receipt Point for any month under a Schedule of Service for Service under Rate Schedule CO_2. The total excess volume of carbon dioxide at a Receipt Point for any month shall be determined by Company as follows:

Total Excess CO_2 Volume = A x (B - C)

Where:

"A" = the total volume of gas received by Company at such Receipt Point;

"B" = the percentage of carbon dioxide by volume of gas received as determined by Company at such Receipt Point; and

"C" = two (2) percent.

If "B" is less than or equal to "C", the Total Excess CO_2 Volume shall be zero.

1.10 "CO_2 Rate" shall mean the CO_2 Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule CO_2.

1.11 "Common Stream Operator" or "CSO" shall mean the person who, with respect to a Receipt Point:

(i) provides Company with the estimates of Flow at the Receipt Point;

(ii) provides Company with the allocation of the estimated Flow~~, Measured Volume~~ and Total ~~Energy~~ Quantity for the Receipt Point to each Customer receiving Service at the Receipt Point; and

(iii) accepts Nominations made by Company on behalf of Customers and confirms the availability of gas to meet Customer's Nominations.

1.12 "Company" shall mean NOVA Gas Transmission Ltd. and any successor to it.

"A" = the gas received by Company from Customer at all of Customer's Receipt Points;

"B" = the gas received by Customer from another Customer through title transfers;

"C" = the gas delivered by Company to Customer at all of Customer's Delivery Points;

"D" = the gas delivered by Customer to another Customer through title transfers;

"E" = the gas allocated to Customer for Gas Used, Gas Lost, and Measurement Variance; and

"F" = the daily recovery of Customer's Inventory imbalance as a result of:

(i) any differences in measurement or allocations between the daily estimated gas received by Company from Customer at all of Customer's Receipt Points and the month end actual ~~volume~~ quantity of gas received by Company from Customer at such Receipt Points;

(ii) any differences in measurement or allocations between the daily estimated ~~volume~~ quantity of gas delivered by Company to Customer at all of Customer's Delivery Points and the month end actual gas delivered by Company to Customer at such Delivery Points;

(iii) any corrections due to measurement or allocations of gas for any prior months; and number of days that the Customer was entitled to such Points to Point Contract Demand under such Schedule of Service in such month;

(ii) the actual volume of gas received by Company from Customer at the Receipt Points under such Schedule of Service; or

(iii) the actual volume of gas delivered by Company to Customer at the Alberta Delivery Point under such Schedule of Service.

1.29 "Emergency Response Compensation Event" or "ERC Event" shall have the meaning attributed to it in Appendix "G" of the Tariff.

1.30 "Export Delivery Contract Demand" shall mean the maximum ~~volume~~ quantity of gas, expressed in GJ or as converted to GJ pursuant to paragraph 15.12, Company may be required to deliver to Customer at the Export Delivery Point on any Day, as set forth in the Schedule of Service.

1.31 "Export Delivery Point" shall mean any of the following points where gas is delivered to a Customer for removal from Alberta under a Schedule of Service:

Alberta-British Columbia Border
Alberta-Montana Border
Boundary Lake Border
Cold Lake Border
Demmitt #2 Interconnect
Empress Border
Gordondale Border
McNeill Border
Unity Border

1.32 "Extraction Delivery Point" shall mean the point in Alberta where gas may be delivered to the Extraction Plant by Company for Customer under a Schedule of Service.

1.42 "FT-P Customer Account" shall mean an account established by Company for Customer to record Customer's transactions related to Service under Rate Schedule FT-P.

1.43 "FT-P Demand Rate" shall mean the FT-P Demand Rate for the distance between the particular Receipt Points and the particular Alberta Delivery Point in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-P.

1.44 "FT-R Demand Rate" shall mean the FT-R Demand Rate for a particular Receipt Point in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-R.

1.45 "FT-RN Demand Rate" shall mean the FT-RN Demand Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule FT-RN for a particular Receipt Point.

1.46 "Gas" or "gas" shall mean all natural gas both before and after it has been subjected to any treatment or process by absorption, purification, scrubbing or otherwise, and includes all fluid hydrocarbons other than hydrocarbons that can be recovered from a pool in liquid form by ordinary production methods.

1.47 "GIA" shall mean the Electricity and Gas Inspection Act, R.S.C. 1985, c. E-4, as amended, and all Regulations issued pursuant to it.

1.48 "Gas Lost" shall mean that ~~volume~~ quantity of gas determined by Company to be the aggregate of:

(i) the total ~~volume~~ quantity of gas lost as a result of a Facilities rupture or leak; and

(ii) any Customer's Inventory that Company reasonably determines to be unrecoverable.

1.49 "Gas Used" shall mean that ~~volume~~ quantity of gas determined by Company to be the total ~~volume~~ quantity of gas used by Company in the operation, maintenance and construction of the Facilities.

1.50 "Gas Year" shall mean a period of time beginning at eight hours (08:00) Mountain Standard Time on the first day of November in any year and ending at eight hours (08:00) Mountain Standard Time on the first day of November of the next year.

1.51 "GJ" shall mean gigajoule, or one billion joules.

~~1.51~~1.52 "Gross Heating Value" shall mean the total ~~megaJoules~~ MJ obtained by complete combustion of one cubic metre of gas with air, the gas to be free of all water vapour and the gas, air and products of combustion to be at standard conditions of fifteen (15) degrees Celsius and one hundred one and three hundred twenty-five thousandths (101.325) kiloPascals (absolute) and all water vapour formed by the combustion reaction condensed to the liquid state.

~~1.52~~1.53 "IT-D Rate" shall mean the IT-D Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule IT-D.

~~1.53~~1.54 "IT-R Rate" shall mean the IT-R Rate for a particular Receipt Point in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule IT-R.

1.55 "J" or "joule" shall mean the base unit for energy as defined by the International System of Units (SI).

~~1.54~~1.56 "kPa" or "kiloPascals " shall mean kiloPascals of pressure (gauge) unless otherwise specified.

~~1.55~~1.57 "Line Pack Gas" shall mean at any point in time that ~~volume~~ quantity of gas determined by Company to be the total ~~volume~~ quantity of gas contained in the Facilities.

~~1.64~~1.66 “Maximum Receipt Pressure” shall mean relative to a Receipt Point the maximum pressure at which Company may require Customer to deliver gas, as set forth in Schedule of Service.

~~1.65~~1.67 “Measurement Variance” shall mean, for any period, after taking into account any adjustment made in accordance with the provisions of paragraph 2.6 of these General Terms and Conditions, the energy equivalent of the amount determined as follows:

MV = (A + B + C) - (D + E)

Where:

“MV” = the Measurement Variance;

“A” = the energy equivalent of gas determined by Company to have been delivered to all Customers during the period;

“B” = the energy equivalent of the aggregate of the Gas Lost and Gas Used during the period;

“C” = the energy equivalent of Line Pack Gas at the end of the period;

“D” = the energy equivalent of gas determined by Company to have been received from all Customers during the period; and

“E” = the energy equivalent of Line Pack Gas at the beginning of the period.

1.68 “MJ” shall mean megajoule, or one million joules.

~~1.66~~1.69 “Month” or “month” shall mean a period of time beginning at eight hours (8:00) Mountain Standard Time on the first day of a calendar month and ending at eight hours (08:00) Mountain Standard Time on the first day of the next calendar month.

~~1.67~~1.70 “Nomination” shall mean, with respect to a Receipt Point or a Delivery Point, a request for Flow made on behalf of a Customer.

~~1.68~~1.71 "Non-Responding Plant" shall have the meaning attributed to it in Appendix "G" of the Tariff.

~~1.69~~1.72 "Officer's Certificate" shall have the meaning attributed to it in subparagraph 4.2.1 of Rate Schedule LRS for Service under Rate Schedule LRS and subparagraph 4.3.1 of Rate Schedule LRS-2 for Service under Rate Schedule LRS-2.

~~1.70~~1.73 "Over-Run Gas" shall mean, in respect of a Customer in a month, the aggregate ~~volume~~ quantity of gas for which an amount for over-run gas is payable by Customer in the Billing Month.

~~1.71~~1.74 "OS Charge" shall mean an OS Charge in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule OS.

~~1.72~~1.75 "Person" shall mean and include Company, a Customer, a corporation, a company, a partnership, an association, a joint venture, a trust, an unincorporated organization, a government, or department of a government or a section, branch, or division of a department of a government.

~~1.73~~1.76 "Points to Point Contract Demand" shall mean the maximum volume of gas Company may be required to receive from Customer at particular Receipt Points and deliver to Customer at a particular Alberta Delivery Point on any day under a Schedule of Service under Rate Schedule FT-P.

~~1.74~~1.77 "Price Point" shall mean Price Point "A", Price Point "B", or Price Point "C", each as defined in paragraph 3.2 of Rate Schedule FT-R and Rate Schedule FT-P.

~~1.75~~1.78 "Primary Term" shall mean for the purposes of any Service provided under any Schedule of Service the term calculated in accordance with the Criteria for Determining Primary Term in Appendix "E" of the Tariff.

~~1.76~~1.79 "Prime Rate" shall mean the rate of interest, expressed as an annual rate of interest, announced from time to time by the Royal Bank of Canada, Main Branch, Calgary, Alberta as the reference rate then in effect for determining interest rates on Canadian dollar commercial loans in Canada.

~~1.77~~1.80 "Project Area" shall mean each of:

(i) the Peace River Project Area;

(ii) the North and East Project Area; and

(iii) the Mainline Project Area,

as described in Company's current Annual Plan. The Project Areas may be amended from time to time by Company in consultation with the Facility Liaison Committee (or any replacement of it), provided Company has given six (6) months notice of such amendment to its Customers.

~~1.78~~1.81 "PT Gas Rate" shall mean the PT Gas Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule PT, based on the incremental gas requirements associated with the Facilities required to provide such Service.

~~1.79~~1.82 "PT Rate" shall mean the PT Rate in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under Rate Schedule PT, based on the incremental operating costs associated with providing such Service plus ten percent.

1.83 "Quantity Multiplier" shall have the meaning attributed to it in subparagraph 6.1 (a) of Rate Schedule STFT.

~~1.80~~1.84 "Rate Schedule" shall mean any of the schedules identified as a "Rate Schedule" included in the Tariff.

~~1.81~~1.85 "Ready for Service Date" shall mean the Day designated as such by Company by written notice to Customer stating that Company has Facilities which are ready for and are capable of rendering the Service applied for by Customer.

~~1.92~~1.96 "Service Termination Date" shall mean the last Day in a month upon which Service shall terminate, as set forth in a Schedule of Service and subject to any renewal thereof.

~~1.93~~1.97 "Storage Delivery Point" shall mean the point in Alberta where gas may be delivered to the Storage Facility by Company for Customer for ultimate receipt from such Storage Facility at the Storage Receipt Point under a Schedule of Service.

~~1.94~~1.98 "Storage Facility" shall mean any commercial facility where gas is stored, that is connected to the Facilities and is available to all Customers.

~~1.95~~1.99 "Storage Receipt Point" shall mean the point in Alberta where gas may be received from the Storage Facility by Company for Customer that was previously delivered to such Storage Facility at the Storage Delivery Point under a Schedule of Service.

~~1.96~~1.100 "Surcharge" shall mean a Surcharge set forth in the Table of Rates, Tolls and Charges which has been fixed by Company or the Board for Service under a Rate Schedule.

~~1.97~~1.101 "Table of Rates, Tolls and Charges" shall mean the Table of Rates, Tolls and Charges setting forth rates, tolls and charges that have been fixed by Company or the Board to be imposed, observed and followed by Company.

~~1.98~~1.102 "Tariff" shall mean this Gas Transportation Tariff, including the Table of Rates, Tolls and Charges, the Rate Schedules, the Service Agreements, Schedules of Service, these General Terms and Conditions and the Appendices.

~~1.99~~1.103 "Tier" shall mean the Tier 1, Tier 2 or Tier 3 CO_2 Rate as set forth in the Table of Rates, Tolls and Charges.

1.104 "TJ" shall mean terajoule, or one trillion joules.

~~1.100~~1.105 “Thousand Cubic Metres” or “10^3m^3” shall mean one thousand (1000) Cubic Metres of Gas.

~~**1.102** “Volume Multiplier” shall have the meaning attributed to it in subparagraph 6.1 (a) of Rate Schedule STFT.~~

~~1.102~~1.106 “Winter Season” shall mean the period commencing on November 1 of any year and ending on the next succeeding March 31.

(b) Notwithstanding subparagraph 3.2 (a), if gas received by Company fails to conform to the quality requirements set forth in paragraph 3.1 above, Company may at its option immediately suspend the receipt of gas, provided however that any such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

(c) Notwithstanding subparagraphs 3.2 (a) and 3.2 (b), if gas received by Company fails to conform to the quality requirements set forth in subparagraph 3.1(e) above, Company shall notify Customer of such failure. If the failure to conform is not remedied by Customer within thirty (30) days, Company shall refuse to accept such gas pending the remedying of such failure, provided however that any such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

3.3 Quality Standard of Gas Delivered at Delivery Points

Gas which Company delivers at Delivery Points shall have the quality that results from gas having been transported and commingled in the Facilities.

4.0 MEASUREMENT

4.1 Method of Measurement

Company may make such measurements and calculations and use such procedures as it deems appropriate in determining volume and energy, provided that the measurements and calculations made and the procedures used comply with any applicable requirements under the GIA.

4.2 Unit of Measurement

4.2.1 The unit of volume for purposes of measurement hereunder shall be a Thousand Cubic Metres.

4.2.2 The unit of energy for purposes of measurement hereunder shall be a GJ.

4.3 Atmospheric Pressure

For the purpose of measurement atmospheric pressure shall be determined by a recognized formula applied to the nearest one hundredth (0.01) kPa absolute and deemed to be constant at the time and location of measurement.

4.4 Flowing Temperature

The temperature of flowing gas shall be determined by means of a recording thermometer or other equipment appropriate for the determination of temperature.

4.5 Determination of Gas Characteristics

The gas characteristics including, without limiting the generality of the foregoing, Gross Heating Value, relative density, nitrogen and carbon dioxide content, shall be determined by continuous recording equipment, laboratory equipment or through computer modeling.

4.6 Exchange of Measurement Information

Company and Customer shall make available to the other, as soon as practicable following written request, all measurement and test charts, measurement data and measurement information pertaining to the Service being provided to Customer.

4.7 Preservation of Measurement Records

Company and Customer shall preserve all measurement test data, measurement charts and other similar records for a minimum period of six (6) years or such longer period as may be required by record retention rules of any duly constituted regulatory body having jurisdiction.

7.2 Pressure Protection

Customer shall provide or cause to be provided suitable pressure relief devices, or pressure limiting devices, to protect the Facilities as may be necessary to ensure that the pressure of gas delivered by Customer to Company at any Receipt Point will not exceed one hundred ten (110%) percent of the Maximum Receipt Pressure.

7.3 The Gas Pressure At Delivery Points

The pressure of gas delivered by Company at any Delivery Point shall be the pressure available from the Facilities at that Delivery Point, provided that such pressure shall not exceed the Maximum Delivery Pressure.

8.0 GAS USED, GAS LOST AND MEASUREMENT VARIANCE

8.1 Company's Gas Requirements

Company may, at its option, either:

(a) take from all Customers at Receipt Points a ~~volume~~ quantity of gas ~~having an energy content~~ equal to the aggregate ~~energy content~~quantity of any or all Gas Used, Gas Lost and Measurement Variance for any period; or

(b) arrange with a Customer or Customers or any other Persons at Receipt Points to take and pay for a ~~volume~~ quantity of gas ~~having an energy content~~ equal to the aggregate ~~energy content~~quantity of any or all Gas Used, Gas Lost and Measurement Variance for any period.

8.2 Allocation of Gas Taken

If Company in any period exercises its option to take a ~~volume~~ quantity of gas as provided for in subparagraph 8.1 (a), each Customer's share of the ~~volume~~ quantity of such gas taken in such period will be a ~~volume~~ quantity equal to the product of the

~~volume~~ quantity of such gas taken in such period and a fraction, the numerator of which shall be the ~~energy content of the~~ aggregate ~~volume~~ quantity of gas received by Company from Customer in such period at all of Customer's Receipt Points and the denominator of which shall be the ~~energy content of the~~ aggregate ~~volume~~ quantity of gas received by Company from all Customers in such period at all Receipt Points.

8.3 Gas Received from Storage Facilities

Notwithstanding anything contained in this article 8.0, any gas received into the Facilities from a gas storage facility that was previously delivered into the gas storage facility through the Facilities shall not be included in any calculation, and shall not be taken into account in any allocation, of Company's gas requirements.

9.0 DELIVERY OBLIGATION

9.1 Company's Delivery Obligation

Subject to paragraph 9.2:

(a) Company's delivery obligation for any period where Company has exercised its option as provided for in subparagraph 8.1 (a), shall be to deliver to all Customers at all Delivery Points the ~~volume~~ quantity~~of gas which has the aggregate energy content of the aggregate volume~~ of gas Company determines was received from all Customers in such period at all Receipt Points, less all Customers share as determined under paragraph 8.2; and

(b) Company's delivery obligation, for any period where Company has exercised its option to purchase gas as provided for in subparagraph 8.1 (b), shall be to deliver to all Customers at all Delivery Points the ~~volume~~ quantity~~of gas which has the aggregate energy content~~ of all gas received from all Customers, other than gas taken from such Customers and paid for pursuant to subparagraph 8.1 (b), in such period at all Receipt Points.

9.2 Variance

Due to variations in operating conditions, the aggregate daily and monthly ~~volumes~~ quantities of gas delivered to all Customers at all Delivery Points, adjusted as provided for in paragraph 9.1, will differ from the aggregate of the corresponding daily and monthly ~~volumes~~ quantities of gas received from all Customers. Customers and Company shall co-operate to keep such differences to the minimum permitted by operating conditions and to balance out such differences as soon as practicable.

9.3 Operating Balance Agreements

Company may enter into agreements and other operating arrangements with any operator of a downstream pipeline facility interconnecting with the Facilities ("downstream operator") respecting the balancing of gas quantities to be delivered by Company and to be received by the downstream operator on any Day at the interconnection of the downstream facility and the Facilities (the "interconnection point"). This may include agreements and operating arrangements providing that for any Day a quantity of gas nominated by a Customer for delivery at the interconnection point may be deemed to have been delivered by Company and received by the downstream operator regardless of the actual flow of gas at the interconnection point on the Day.

9.4 Energy Content and Gas Quality

Gas delivered by Company to Customer at any of Customer's Delivery Points shall have the energy content and quality that results from the gas having been commingled in the Facilities.

(a) Company and Customer shall have no liability for, nor obligation to indemnify and save harmless the other from, any claim, demand, suit, action, damage, cost, loss or expense which was not reasonably foreseeable at the time of the act, omission or default;

(b) Company shall have no liability to Customer, nor obligation to indemnify and save harmless Customer, in respect of Company's failure for any reason whatsoever, other than Company's wilful default, to provide Service pursuant to the provisions of Customer's Service Agreement;

(c) the failure by Company for any reason whatsoever to receive gas from Customer or deliver gas to Customer shall not suspend or relieve Customer from the obligation to pay any rate, toll, charge or other amount payable to Company; and

(d) Company shall have no liability to Customer, nor obligation to indemnify and save harmless Customer, in respect of Company providing Service to any Customer under Rate Schedule CO_2 and/or Rate Schedule PT.

14.0 EXCHANGE OF INFORMATION

14.1 Provision of Information

Company and Customer shall make available, on request by either made to the other, certificates, estimates and information as shall be in their possession, and as shall be reasonably required by the other.

14.2 Additional Information

Notwithstanding paragraph 14.1, Customer shall furnish Company with such estimated daily, monthly and annual ~~volumes~~ quantities as Company may require, with respect to any Service provided or to be provided, together with any data that Company may require in order to design, operate and construct facilities to meet Customer's requirements.

15.6 No Interest in Facilities

Customer does not acquire any right to, title to or interest in the Facilities or any part thereof nor does Company dedicate any portion of the Facilities to Service for any Customer.

15.7 Forbearance

Forbearance to enforce any provision of the Tariff shall not be construed as a continuing forbearance to enforce any such provision.

15.8 Inconsistency

In the event that there is any inconsistency between any provision of these General Terms and Conditions, any provision of any Rate Schedule or any provision of any Service Agreement, the provision of the Service Agreement shall prevail over the Rate Schedule which in turn shall prevail over the General Terms and Conditions.

15.9 Amendment of Service Agreement

No amendment or variation of any term, condition or provision of any Schedule of Service or Service Agreement shall be of any force or effect unless in writing and signed by Company.

15.10 Priority for New or Additional Service

Company may from time to time establish procedures respecting priority of entitlement for Customers seeking new or additional Service.

15.11 Establishment of Procedures and Pilot Projects

Company may from time to time establish procedures, including procedures for carrying out and evaluating any pilot projects Company determines to be necessary or desirable, respecting or relating to or affecting any Service or any term, condition or provision contained within the Tariff.

15.12 Conversion of Service Agreements to Energy Units

(a) Effective November 1, 2006, for any Service Agreements under Rate Schedules FT-D, FT-DW and STFT, the Export Delivery Contract Demand set out in each new Schedule of Service shall be expressed in energy units (GJ).

(b) Effective November 1, 2006, for any Service Agreements under Rate Schedules FT-D, FT-DW and STFT, the Export Delivery Contract Demand set out in each existing Schedule of Service shall be converted to GJ using the following Export Delivery Point energy conversion rates:

Alberta-British Columbia Border	37.98 MJ per m^3
Alberta-Montana Border	37.71 MJ per m^3
Boundary Lake Border	39.55 MJ per m^3
Cold Lake Border	37.52 MJ per m^3
Demmitt #2 Interconnect	39.57 MJ per m^3
Empress Border	37.52 MJ per m^3
Gordondale Border	40.05 MJ per m^3
McNeill Border	37.57 MJ per m^3
Unity Border	37.78 MJ per m^3

TERMS AND CONDITIONS RESPECTING
CUSTOMER'S INVENTORIES AND RELATED MATTERS

1.0 DEFINITIONS

1.1 Capitalized terms used in this Appendix have the meanings attributed to them in the Tariff unless otherwise defined in this Appendix.

In this Appendix:

1.2 "Balanced Zone" shall mean for each Day, subject to Articles 6.0 and 7.0, the range of a Customer's Inventory between the amounts determined as follows:

(i) the positive value of the greater of:

(a) two (2) TJ's; or

(b) the sum of:

(I) four (4) percent of the quotient obtained when the sum of the Total ~~Energy~~ Quantity for all Receipt Points in the Billing Month for a Customer (excluding all Total ~~Energy~~ Quantity in relation to storage facilities and title transfers) is divided by the total number of days in the Billing Month; and

(II) four (4) percent of the quotient obtained when the sum of the Total ~~Energy~~ Quantity for all Delivery Points in the Billing Month for a Customer (excluding all Total ~~Energy~~ Quantity in relation to storage facilities and title transfers) is divided by the total number of days in the Billing Month; and

(ii) the negative value of the amount determined in subparagraph 1.2(i).

1.3 “Daily Plan” shall mean the written plan Customer shall provide to Company which shall set out all information on how Customer will comply with this Appendix, including all known or anticipated changes to Customer’s Inventory for the Day.

~~**1.4** “Measured Volume” shall mean the aggregate of the actual measured volumes for a Billing Month for a Receipt Point or a Delivery Point.~~

~~1.5~~1.4 “NIT List” shall mean the list provided to Company by Customer, of at least 10 active title transfers of Customer’s Inventory excluding title transfers between:

(i) agency accounts;

(ii) affiliates; and

(iii) Customers whose marketing and management services are provided by the same entity.

~~1.6~~1.5 “Pipeline Tolerance Level” shall mean the ~~volume~~ quantity of linepack in the Facilities determined by Company from time to time to enable the optimum operation of the Company’s Facilities.

~~**1.7** “TJ’s” shall mean TeraJoules.~~

~~1.8~~1.6 “Total ~~Energy~~Quantity” shall mean the aggregate energy calculated ~~for the Measured Volume, using the related Gross Heating Values,~~ for a Billing Month for a Receipt Point or a Delivery Point.

electronically gathered data is not available for any reason, by taking into account the most recent measurement data, subsequent changes in Nominations and available historical data.

(ii) Flow at a Receipt Point will be allocated to each Customer at a Receipt Point based on the allocation made by the Common Stream Operator, if available, or, if for any reason an allocation for any Customer is unavailable from the Common Stream Operator, in the same proportion as the Customer's Nomination at the Receipt Point is of the aggregate of all Nominations for all Customers at the Receipt Point.

(iii) Flow at a Delivery Point will be estimated based on electronically gathered data, if available, or, if electronically gathered data is not available for any reason, by taking into account the most recent measurement data, subsequent changes in Nominations and available historical data.

(iv) Flow at a Delivery Point will be allocated to each Customer at a Delivery Point in the same proportion as such Customer's Nomination at the Delivery Point is of the aggregate of all Nominations for all Customers at the Delivery Point.

3.2 Company will determine ~~Measured Volumes and Total Energy,~~ and ~~the allocation~~ allocate ~~of Measured Volumes and~~ Total ~~Energy~~Quantity at Receipt Points and Delivery Points as follows:

(i) ~~Measured Volumes and~~ Total ~~Energy~~ Quantity at Receipt Points for a Billing Month will be determined based on final measurement data obtained by Company in the month following the Billing Month.

(ii) ~~Measured Volumes and~~ Total ~~Energy~~ Quantity at a Receipt Point for a Billing Month will be allocated by the Common Stream Operator to each Customer receiving Service at the Receipt Point during the Billing Month.

(iii) ~~Measured Volumes and~~ Total ~~Energy~~ Quantity at Delivery Points for a Billing Month will be determined based on final measurement data obtained by Company in the month following the Billing Month.

(iv) ~~Measured Volumes and~~ Total ~~Energy~~ Quantity at a Delivery Point for a Billing Month will be allocated to each Customer receiving Service at the Delivery Point during the Billing Month in the same proportion as such Customer's Nomination at the Delivery Point is of the aggregate of all Nominations for all Customers at the Delivery Point.

3.3 Company's determination~~s~~ and allocation of Flows~~, Measured Volumes~~ and Total ~~Energy~~ Quantity ~~and the allocation of Flows, Measured Volumes and Total Energy~~ at Receipt Points and Delivery Points, made in accordance with these terms and conditions, will be conclusive and binding on Customers for the purposes of any action taken by Company pursuant to these terms and conditions or any provision contained within the Tariff.

4.0 DAILY BALANCED ZONE REQUIREMENTS

4.1 On each Day Customer shall ensure that such Customer's Inventory shall be within the Balanced Zone at the end of such Day. Customer shall have until 10:30 MST on the following Day to get Customer's Inventory within the Balanced Zone. It is the Customer's responsibility to monitor Customer's Inventory and balancing requirements utilizing the information tools provided by Company. Company may on any Day request Customer to provide a Daily Plan and Customer shall provide such Daily Plan to Company on or before 16:00 hours (Calgary clock time) on such Day.

4.2 If Customer fails to comply with paragraph 4.1 on any Day, Company, to the extent necessary to ensure compliance with paragraph 4.1, may:

(i) Cancel prior to the end of the next Day all or a portion of any title transfer(s) set out in NIT List. If Customer has not provided Company with a NIT List,

(ii) Customer's access to any electronic tool that allows Customer to transact business on Company's Facilities, provided however such suspension shall not relieve Customer of its obligation to pay any rate, toll charge or other amount payable to Company.

5.0 DISCRETION

5.1 For any Day a Customer's Inventory may be outside the Balanced Zone by an amount equal to the sum of the following:

(i) The difference between the estimated extrapolated physical receipt flow at 16:00 (Calgary clock time) and the finalized physical receipt ~~volume~~ quantity at the end of such Day;

(ii) The difference between the forecasted extraction ~~volumes~~ quantities as provided to Company by the Extraction Plants, at 16:00 (Calgary clock time) and the extraction ~~volumes~~ quantities as provided to Company by the Extraction Plants, at the end of such Day;

(iii) Historical changes that are applied by Company to Customer's Inventory during the Day; and

(iv) Net change for such Day to a border delivery nomination between the requested ~~volume~~ quantity and allowable ~~volume~~ quantity when Company implements a border delivery restriction and notification of such restriction to Customer occurs after 16:00 (Calgary clock time).

Provided however, Customer shall cause Customer's Inventory to be within the Balanced Zone by the end of the Day following such Day.

5.2 If Customer fails to comply with paragraph 5.1, Company may implement the remedies set out in subparagraphs 4.2 (i), (ii), and (iii). If Customer fails to comply with paragraph paragraphs 6.2 and 6.3, immediately change the Pipeline Tolerance Level to a level determined by Company. Customer's Inventory shall be within Customer's changed Balanced Zone within twenty-four (24) hours from the effective time of the revised Pipeline Tolerance Level as posted by Company on its electronic bulletin board.

7.0 NIT ONLY CUSTOMERS

7.1 Notwithstanding anything contained in this Appendix, a Customer who does not have any physical receipt ~~volumes~~ quantities or any physical delivery ~~volumes~~quantities, excluding Total ~~Energy~~ Quantity in relation to storage facilities, shall not be entitled to a Balanced Zone and must balance to zero (0) at the end of each Day.

7.2 If on any Day, Company determines such Customer did not balance to zero (0) at the end of such Day, Company shall be entitled to cancel all or a portion of any title transfer(s) set out in NIT List, as Company determines necessary to ensure Customer balances to zero (0). If Customer has not provided Company with a NIT List, Company shall be entitled to randomly select which title transfer(s) shall be cancelled and/or reduced, commencing with the shortest term of title transfer(s) and excluding title transfers between:

(a) agency accounts;

(b) affiliates; and

(c) Customers whose marketing and management services are provided by the same entity.

Any title transfer(s) selected by Company to balance a Customer's Inventory with a term longer than one day, shall be deemed to be cancelled for the balance of that term. After such cancellation, Company shall use reasonable efforts to contact and advise the

Customer and the counter party to the title transfer that all or a portion of the title transfer has been cancelled.

7.3 If Customer fails to comply with paragraph 7.1 for three (3) consecutive Days, Company, in addition to any other remedy it may have, shall be entitled to suspend on two (2) hours written notice to Customer:

(i) All or a portion of Service to such Customer, provided however such suspension shall not relieve Customer of its obligation to pay any rate, toll charge or other amount payable to Company; and

(ii) Customer's access to any electronic tool that allows Customer to transact business on Company's Facilities, provided however such suspension shall not relieve Customer of its obligation to pay any rate, toll charge or other amount payable to Company.

8.0 ADMINISTRATION OF CUSTOMER'S INVENTORIES AT MONTH END

8.1 On one (1) occasion each month Company, using the Total ~~Energy~~ Quantity and allocation of Total ~~Energy~~ Quantity for each of Customer's Receipt Points and Delivery Points on the pipeline system, will determine Customer's Inventory for each Customer receiving Service in the Billing Month. Company's monthly determination of Customer's Inventory will incorporate the revision of any allocation of Flow provided to Company in respect of any prior period and the reallocation of the Flow among Customers.

8.2 Company will notify a Customer if such Customer's Inventory is negative. A Customer may reduce such negative amount through one (1) or a series of inventory transfers carried out in accordance with Company's Terms and Conditions Respecting Title Transfers. If Customer does not reduce such negative Customer's Inventory through title

1.19 "Flow Proration Factor" shall mean the aggregate of all Customers' estimated average energy Flow, based on unfinalized custody transfer measurement as measured by Company, at all Receipt Points in the Area of Impact for the Duration of the ERC Event divided by the aggregate of all Customers' estimated energy Flow, based on unfinalized custody transfer measurement as measured by Company, at all Receipt Points in the Area of Impact immediately prior to the ERC Event.

1.20 "Gas Balance Recovery Period" shall mean the period of thirty days over which the Company recovers from Customer the difference between such Customer's month end estimated inventory and month end actual inventory.

1.21 "Gas Balance Recovery Price" shall mean the price per GJ calculated as follows:

$$\text{GBRP} = \left(\frac{A}{30} \times B\right) + \left(\frac{C}{30} \times D\right)$$

Where:

"GBRP" = Gas Balance Recovery Price;

"A" = the number of days between the date the Gas Balance Recovery Period associated with the ERC Event begins and the last day of the month following the month of the ERC Event;

"B" = the average of the same day prices (as defined by Natural Gas Exchange Inc. on its' website) per GJ for the gas traded on NGX for the period described in "A" above;

"C" = 30 - "A"; and

"D" = the volume weighted average of near month prices (as defined by Natural Gas Exchange Inc. on its' website) per GJ for the gas traded on NGX during the period described in "A" above.

~~**1.22** "GJs" shall mean gigaJoules.~~

APPENDIX 3C: RATE FLOW CHART (ENERGY CONVERSION)

2005 Illustrative Rate Calculation – Energy Conversion

TOTAL REVENUE REQUIREMENT	$1,160.0 Million

MINUS

NON TRANSPORTATION REVENUE	$Million
FCS	$ 5.4
OS	$ 1.1
PTS	$ 0.9
CO_2	$ 15.4
Total	$ 22.3

EQUALS

TRANSPORTATION REVENUE REQUIREMENT	$1,137.6 Million

MINUS

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

*Revenues adjusted to account for NGTL's contribution.

MINUS

OTHER TRANSPORTATION REVENUE

	(Tj/d)[1]	(Bcf/d)	($10^6 m^3/d$)	$Million
IT-D[2]	1,109.69	1.04	29.36	$ 64.8
STFT	0.00	0.00	0.00	$ 0.0
IT-R		2.07	58.37	$123.6
FT-P		0.38	10.73	$ 22.1
FT-RN		0.07	1.91	$ 5.2
FT-DW	0.00	0.00	0.00	$ 0.0
FT-A		1.03	28.92	$ 5.3
Total	1,109.69	4.59	129.29	$ 221.1

[1] Converted at 37.8 Mj/m^3.
[2] Revenues adjusted to account for Alternate Access.

EQUALS

FIRM TRANSPORTATION REVENUE REQUIREMENT	$869.1 Million

2005 Illustrative Rate Calculation – Energy Conversion cont.

FIRM TRANSPORTATION REVENUE REQUIREMENT $869.1 Million

DIVIDED BY

CONTRACT DEMAND	(Tj)[1]	(Bcf)	(10^6m^3)
Delivery	2,859,188.5	2,684.74	75,639.9
Receipt		2,920.10	82,271.0
Total		5,604.85	157,910.9

[1] Converted at 37.8 Mj/m^3.

EQUALS

FIRM TRANSPORTATION PRICE $0.1456/Gj/d $0.1551/Mcf/d $5.504/$10^3m^3$/d

MULTIPLIED BY

RECEIPT CONTRACT DEMAND

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

EQUALS

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT

$452.8 Million

MULTIPLIED BY

DELIVERY CONTRACT DEMAND

2,859,188.5 Tj

EQUALS

FIRM TRANSPORTATION DELIVERY REVENUE REQUIREMENT

$416.3 Million

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT $452.8 Million

ALLOCATE TO EACH RECEIPT POINT

RECEIPT TRANSPORTATION REVENUE

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

APPENDIX 3D: HOUSEKEEPING TARIFF CHANGES (BLACKLINED)

<u>Summary of Amendments</u>

1. Cover Page

(i) Updated contact name for Tariff.

2. Rate Schedule FT-R, Firm Transportation – Receipt

(i) Amended paragraph 12.2 [Irrevocable Notice] – changed from “subject to Financial Information and Security provisions” to “subject to the Financial Assurances provisions.”

3. Rate Schedule FT-D, Firm Transportation – Delivery

(i) Amended paragraph 10.2 [Irrevocable Notice] – changed from “subject to the Financial Information and Security provisions” to “subject to the Financial Assurances provisions.”

4. Rate Schedule FT-DW, Firm Transportation – Delivery Winter

(i) Amended paragraph 5.3 [Irrevocable Notice] – changed from “subject to the Financial Information and Security provisions” to “subject to the Financial Assurances provisions.”

5. Rate Schedule FT-A, Firm Transportation – Alberta Delivery

(i) Amended paragraph 9.2 [Irrevocable Notice] – changed from “subject to Financial Information and Security provisions” to “subject to the Financial Assurances provisions.”

6. Rate Schedule FT-X, Firm Transportation - Extraction

(i) Amended paragraph 9.2 [Irrevocable Notice] – changed from “subject to Financial Information and Security provisions” to “subject to the Financial Assurances provisions.”

7. Rate Schedule STFT, Short Term Firm Transportation – Delivery

(i) Amended subparagraph 2.2(b) [Service Description and Availability] – capitalized the term “Financial Assurances.”

(ii) Amended Schedule of Service – changed Bid Price from “day” to “Month.”

8. Rate Schedule FT-P, Firm Transportation – Alberta Points to Point

(i) Amended paragraph 4.4 [Customer’s Monthly Delivery Point Over-Run Gas Charge] – capitalized “Over-Run.”

(ii) Amended paragraph 10.2 [Irrevocable Notice] – changed from “subject to Financial Information and Security provisions” to “subject to the Financial Assurances provisions.”

9. Rate Schedule LRS, Load Retention Service

(i) Amended subparagraph 4.3.1(b) [Aggregate of Customer’s Over-Run Gas Charges] – added Rate Schedule FT-RN to the Receipt Contract Demand.

10. Rate Schedule LRS-2, Load Retention Service - 2

(i) Amended paragraph 4.4.2(v) [Allocation of Gas Delivered] – corrected reference from subparagraph 4.4.2 (iv) to subparagraph 4.4.2 (v).

(ii) Amended paragraph 11.1 [Gas Used] – deleted “billing” from “billing system” to refer to all Company’s systems.

(iii) Amended paragraph 13.1 [Priority During Interruptions] – added LRS-3 and FT-DW to the list of services having equal priority to LRS-2.

(iv) Corrected typo “IN WIT~~H~~NESS WHEREOF.”

11. Rate Schedule LRS-3, Load Retention Service - 3

(i) Amended paragraph 6.2 [Renewal of Service] – changed from "subject to Financial Information and Security provisions" to "subject to the Financial Assurances provisions."

12. Rate Schedule IT-D, Interruptible Transportation – Delivery

(i) Amended paragraph 7.2 [Irrevocable Notice] – changed from "subject to Financial Information and Security provisions" to "subject to the Financial Assurances provisions."

13. Rate Schedule IT-S, Interruptible – Access to Storage

(i) Amended paragraph 3.2 [Aggregate of Customer's Surcharges] – capitalized "Rate" for reference to "Table of Rates, Tolls and Charges."

(ii) Amended subparagraph 5.2(ii) [Storage Information] – corrected typo "of" to "or."

(iii) Amended paragraph 8.2 [Irrevocable Notice] – changed from "subject to Financial Information and Security provisions" to "subject to the Financial Assurances provisions."

14. Rate Schedule CO_2 – CO_2 Management Service

(i) Amended paragraph 7.2 [Renewal Notification] – changed from "subject to Financial Information and Security provisions" to "subject to the Financial Assurances provisions."

15. Appendix H – Terms and Conditions Respecting CO_2 Management Service

(i) Amended paragraphs 2.3 and 2.4 [CO_2 Management Service Cap] – changed name from the "Tolls, Tariff & Procedures Committee" to the "Tolls, Tariff, Facilities & Procedures Committee (TTFP)."

(ii) Amended paragraph 3.1 [CO_2 Receipt Zone] – added reference to "an Alberta Delivery Point or an Extraction Delivery Point" and deleted definition of CPO. CPO is already defined in the General Terms and Conditions.

GAS TRANSPORTATION TARIFF

OF

NOVA GAS TRANSMISSION LTD.

Please address communications concerning this Tariff to:

NOVA Gas Transmission Ltd.
450 First Street S.W.
Calgary, Alberta
T2P 5H1

Attention: ~~Trudy Eisele~~Wendy West

12.0 RENEWAL OF SERVICE

12.1 Renewal Notification

Customer shall be entitled to renew all or any portion of Service under a Schedule of Service under Rate Schedule FT-R as Service under either Rate Schedule FT-R or Rate Schedule FT-P, if Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not specify which Rate Schedule the Service is to be renewed under, the Service shall be renewed under Rate Schedule FT-R. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

12.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 12.1 shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

12.3 Renewal Term

Customer's notice shall specify a renewal term of not less than one (1) year consisting of increments of whole months. The Price Point for the renewal term shall be determined in the manner described in paragraph 3.2 based on the length of the renewal term requested by Customer.

13.0 APPLICATION FOR SERVICE

13.1 Applications for Service under this Rate Schedule FT-R shall be in such form as Company may prescribe from time to time.

10.0 RENEWAL OF SERVICE

10.1 Renewal Notification

Customer shall be entitled to renew all or any portion of Service under a Schedule of Service under Rate Schedule FT-D, if Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

10.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 10.1 shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

10.3 Renewal Term

Customer's notice shall specify a renewal term of not less than one (1) year consisting of increments of whole months.

11.0 APPLICATION FOR SERVICE

11.1 Applications for Service under this Rate Schedule FT-D shall be in such form as Company may prescribe from time to time.

12.0 GENERAL TERMS AND CONDITIONS

12.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule FT-D are applicable to Rate Schedule FT-D

5.2 Renewal of Service

Customer may be entitled to renew all or a portion of Service under Rate Schedule FT-DW for a renewal term of two (2) consecutive Winter Seasons provided that:

(i) Customer has given written notice to Company of such renewal on or before October 31 of the year which is two (2) consecutive Winter Seasons prior to the Service Termination Date; and

(ii) Company determines capacity shall be made available.

If Customer does not provide such renewal notice and/or Company determines capacity is not available, the Service shall expire on the Service Termination Date.

5.3 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 5.2 shall be irrevocable two (2) consecutive Winter Seasons prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

5.4 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service for Service under Rate Schedule FT-DW.

6.0 CAPACITY RELEASE

6.1 A Customer entitled to receive Service under Rate Schedule FT-DW shall not be entitled to reduce Customer's FT-DW Contract Demand for all or any portion of its Service under a Schedule of Service under Rate Schedule FT-DW.

8.0 TITLE TRANSFERS

8.1 A Customer entitled to receive Service under Rate Schedule FT-A may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

9.0 RENEWAL OF SERVICE

9.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule FT-A, if Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

9.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 9.1 shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

9.3 Renewal Term

Customer's notice shall specify a renewal term of not less than one (1) year consisting of increments of whole years.

7.0 TERM SWAPS

7.1 A Customer entitled to receive Service under Rate Schedule FT-X shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate Schedule FT-X with the Service Termination Date under any Schedule of Service.

8.0 TITLE TRANSFERS

8.1 A Customer entitled to receive Service under Rate Schedule FT-X may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

9.0 RENEWAL OF SERVICE

9.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule FT-X, if Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

9.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 9.1 shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

RATE SCHEDULE STFT

SHORT TERM FIRM TRANSPORTATION - DELIVERY

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule STFT shall mean the delivery of gas to Customer at Customer's Export Delivery Points (the "Service") which includes the transportation of gas Company determines necessary to provide services under the Tariff.

2.2 The Service is available to any Customer requiring the delivery of gas at designated Export Delivery Points during the Winter Season provided that:

(a) Customer has executed a Service Agreement and Schedule of Service under Rate Schedule STFT;

(b) Customer, prior to the commencement of the bidding process set out in article 4.0, has provided Company with ~~f~~Financial ~~a~~Assurances as required by Company pursuant to article 10.0 of the General Terms and Conditions of the Tariff; and

(c) Company has accepted Customer's bid pursuant to article 4.0.

2.3 A standard form Service Agreement for Service under this Rate Schedule STFT is attached.

SCHEDULE OF SERVICE
RATE SCHEDULE STFT

CUSTOMER: •

•
•
•

ATTENTION: •
PHONE: • FAX: •

Schedule of Service Number	Export Delivery Point Number and Name	Maximum STFT Capacity $10^3m^3/d$	Minimum STFT Capacity $10^3m^3/d$	Bid Price $\$/10^3m^3/$~~d~~ Month	Block Period	Billing Commencement	Service Termination Date	Allocated STFT Capacity $10^3m^3/d$
•	• •	•	•	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

Schedule of Service for Rate Schedule FT-P for the month preceding such Billing Month; and

"Z" = the highest IT-R Rate at the Receipt Points set out in such Schedule of Service.

4.4 Customer's Monthly Delivery Point Over-Run Gas Charge

Customer's charges for Delivery Point Over-Run Gas in a Billing Month for Service under Rate Schedule FT-P shall be equal to the sum of the monthly charges for such Over-Run Gas for each of Customer's Schedule of Service under Rate Schedule FT-P, determined as follows:

MOC = V x Z

Where:

"MOC" = the monthly charge for such Over-Run Gas under such Schedule of Service;

"V" = total volume of gas allocated to Customer by Company as Delivery Over-~~r~~Run Gas in accordance with paragraph 4.9 for Service under such Schedule of Service for Rate Schedule FT-P for the month preceding such Billing Month; and

"Z" = the FT-A Rate.

4.5 The calculation of Customer's charge for Over-Run Gas in paragraphs 4.3 and 4.4 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

10.0 RENEWAL OF SERVICE

10.1 Renewal Notification

Customer shall be entitled to renew all or any portion of Service under a Schedule of Service under Rate Schedule FT-P as Service under either Rate Schedule FT-P or Rate Schedule FT-R, provided Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not specify which Rate Schedule the Service is to be renewed under, the Service shall be renewed under Rate Schedule FT-P. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

10.2 Irrevocable Notice

Customer's notice shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

10.3 Renewal Term

Customer's notice shall specify a renewal term of not less than one (1) year consisting of increments of whole months. The Price Point for the renewal term shall be determined in the manner described in paragraph 3.2 based on the length of the renewal term requested by Customer.

11.0 ACCOUNT BALANCE

11.1 Notwithstanding paragraph 4 and 5 of the "Terms and Conditions Respecting Customer's Inventories and Related Matters" in Appendix "D" of the Tariff, Company will (if required) once each Day and once each month balance each FT-P Customer Account to zero.

The result of the calculations made in accordance with subparagraph 4.2.4 (ii) shall be the LRS Billing Adjustment.

Eligible LRS Contract Demand will not be considered for the determination of the LRS Billing Adjustment unless Customer has satisfied Company in the form of a valid Officer's Certificate, that the volumes of gas received were delivered to the Empress Border and McNeill Border Export Delivery Point within the Month with the exception of any volume of gas to have been delivered from Facilities into a storage facility.

4.3 Aggregate of Customer's Over-Run Gas Charges

4.3.1. In the event that Company determines in respect of a Billing Month that Company has received from Customer, in the month preceding such Billing Month, a volume of gas at any Receipt Point identified in Appendix "1" of this Rate Schedule in excess of:

(a) the aggregate of the products obtained when each of the LRS Contract Demand and LRS-3 Contract Demand in effect for Customer in respect of Rate Schedules LRS and LRS-3, in the month preceding such Billing Month, is multiplied by the number of Days in such month that such LRS Contract Demand and LRS-3 Contract Demand was in effect; plus

(b) the aggregate of the products obtained when each of the Receipt Contract Demand in effect for Customer in respect of Rate Schedule FT-R and Rate Schedule FT-RN, in the month preceding such Billing Month, is multiplied by the number of Days in such month that the Receipt Contract Demand was in effect,

then Customer shall pay to Company an amount equal to the product of a volume equal to such excess and the IT-R Rate for the applicable Receipt Point.

4.3.2. The calculation of Customer's Over-Run Gas charge in subparagraph 4.3.1 shall not take into account Customer's Inventory on the last day of the month preceding the Billing Month.

(v) fifthly to service to LRS-2 Customer under Rate Schedule IT-D for such A/BC Export Delivery Point. If LRS-2 Customer is not entitled to service under Rate Schedule IT-D at such A/BC Export Delivery Point, LRS-2 Customer shall be deemed to have been entitled to such service for the purposes of this subparagraph 4.4.2 (~~i~~v) and shall pay to Company an amount determined under article 4.0 of Rate Schedule IT-D for the volumes allocated under this subparagraph 4.4.2 (~~i~~v).

5.0 TERM OF SERVICE AGREEMENT

5.1 The term of the Service Agreement under Rate Schedule LRS-2 shall commence on the effective date of the Board's Order approving Service under Rate Schedule LRS-2 and shall expire on October 31, 2013, provided however nothing herein shall relieve LRS-2 Customer or Company from any obligation which arose or accrued on or prior to October 31, 2013; and further provided that the LRS-2 Adjustments for the last two Billing Months of the Service Agreement under Rate Schedule LRS-2 shall be paid by the Company to LRS-2 Customer on or before December 31, 2013.

6.0 TRANSFER OF LRS-2 SERVICE

6.1 LRS-2 Customer shall not be entitled to transfer all or any portion of Service under Rate Schedule LRS-2 to any other Receipt Point or Delivery Point. LRS-2 Customer shall not be entitled to convert Service under Rate Schedule LRS-2 to any other service under any other Rate Schedule.

7.0 TERM SWAP OF LRS-2 SERVICE

7.1 LRS-2 Customer entitled to receive Service under Rate Schedule LRS-2 shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate

11.0 GAS USED

11.1 In respect of volumes that are transported utilizing Service under Rate Schedule LRS-2, LRS-2 Customer shall not be charged for nor shall any deduction be made for that portion of Gas Used which is attributable to gas used for compression. In respect of volumes that are transported utilizing Service under Rate Schedule LRS-2, Company shall also not charge LRS-2 Customer nor shall it make any deduction for that portion of Gas Used which is attributable to gas used for heating and pipeline losses until Company's ~~billing~~ systems ~~is~~are capable of separating Gas Used into the following components:

(i) gas used for compression;

(ii) gas used for heating; and

(iii) pipeline losses.

12.0 AUDIT RIGHTS

12.1 Company shall be entitled to audit, at its sole discretion and expense, at any time it determines necessary, any and all documents related to any Officer's Certificate and the contents thereof, in order to verify the accuracy of such Officer's Certificate, provided that any such audit shall be carried out within 24 months of the month to which such Officer's Certificate relates.

13.0 PRIORITY DURING INTERRUPTIONS

13.1 For the purposes of paragraph 11.4 of the General Terms and Conditions of the Tariff, Service under Rate Schedule LRS-2 shall have equal priority to service under Rate Schedule FT-R, FT-RN, FT-P, FT-A, FT-X, STFT, LRS, LRS-3, ~~and~~ FT-D, and FT-DW as the case may be.

shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix “F” of the Tariff shall be given via Company’s electronic bulletin board (“EBB”). Company shall not accept any such Notice for those matters listed in Appendix “F” via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

8. The terms and conditions of Rate Schedule LRS-2, the General Terms and Conditions and Schedule of Service under Rate Schedule LRS-2 are by this reference incorporated into and made a part of this Service Agreement.

IN WIT~~I~~NESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

(ii) the renewal volume specified by Customer for each Schedule of Service for Service under Rate Schedule LRS-3 shall be less than or equal to LRS-3 Contract Demand for such Schedule of Service.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10.0 of the General Terms and Conditions.

6.3 Irrevocable Renewal Notice

Customer's notice to renew pursuant to paragraph 6.2 shall be irrevocable twelve (12) months prior to the Service Termination Date.

6.4 Renewal Term

Customer's renewal notice shall specify a renewal term that:

(i) shall be a minimum of one (1) year consisting of increments of whole months; and

(ii) shall have a Termination Date no later that twenty (20) years from the Billing Commencement Date of the Initial LRS-3 Term.

6.5 Termination

Customer shall be entitled to terminate the Service Agreement in whole and not in part at the end of the Initial LRS-3 Term or any time after the Initial LRS-3 Term provided that Customer gives Company twelve (12) months prior written notice. If Customer does not provide such termination notice to Company, Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedule of Service for Service under Rate Schedule LRS-3.

6.0 TITLE TRANSFERS

6.1 A Customer entitled to receive Service under Rate Schedule IT-D may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

7.0 RENEWAL OF SERVICE

7.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule IT-D if Customer gives notice to Company of such renewal at least one (1) month prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

7.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 7.1 shall be irrevocable one (1) month prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

7.3 Renewal Term

The renewal term shall consist of increments of whole years and shall not be less than one (1) year.

shall charge for such volumes in accordance with the allocations determined by Company in paragraph 4.1.

(iii) If the operator of the gas storage facility fails to provide information to Company's satisfaction that all or a portion of the volume of gas delivered by Company at the Storage Delivery Point connected to a Storage Facility is for the sole purpose of storage and ultimate receipt by Company from such Storage Facility at the Storage Receipt Point, then Company shall charge for such volumes in accordance with the allocations determined by Company in paragraph 4.2.

3.2 Aggregate of Customer's Surcharges

The aggregate of Customer's Surcharges for a Billing Month shall be equal to the sum of all Surcharges set forth in the Table of ~~r~~Rates, Tolls and Charges applicable to each of Customer's Schedules of Service under Rate Schedule IT-S.

3.3 Aggregate Charge for Service

Customer shall pay for each Billing Month the sum of the amounts calculated in accordance with paragraphs 3.1 and 3.2.

4.0 ALLOCATION OF GAS RECEIVED AND DELIVERED

4.1 Allocation of Gas Received

Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of this Tariff, and without regard to how gas may have been nominated, the aggregate volume of gas received at a Storage Receipt Point for Customer, shall be allocated as follows:

(i) the cumulative total of the volume of gas delivered to the Storage Delivery Point for Customer by Company; and

(ii) the cumulative total of the volume of gas received at the Storage Receipt Point by Company for Customer.

5.2 If the operator of a gas storage facility fails to provide Company with the information requested with respect to any month within the time provided by Company for a response to Company's request:

(i) the gas received at the Storage Receipt Point for Customer for such month shall be deemed to have been received for Customer at the Storage Receipt Point under Rate Schedule IT-R and Customer shall pay the IT-R Rate applicable to such Storage Receipt Point in respect of such volume.; and

(ii) the gas delivered at the Storage Delivery Point for Customer for such month shall be deemed to have been delivered by Customer at the Storage Delivery Point under Rate Schedule IT-D and Customer shall pay the IT-D Rate in respect to such volume regardless of whether ~~of~~or not such Storage Delivery Point is an Export Delivery Point.

6.0 TERM OF SERVICE

6.1 Term of Service at a Storage Receipt Point and Delivery Point

The term for any Schedule of Service for Service under Rate Schedule IT-S at each Storage Receipt Point and at each Storage Delivery Point shall be the term requested by Customer, provided that the term is a minimum of one (1) month and terminates on the last day of a Gas Year.

6.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service under Rate Schedule IT-S.

7.0 TITLE TRANSFERS

7.1 A Customer entitled to receive Service under Rate Schedule IT-S may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

8.0 RENEWAL OF SERVICE

8.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule IT-S if Customer gives notice to Company of such renewal at least one (1) month prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

8.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 8.1 shall be irrevocable one (1) month prior to the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions.

of such desire for renewal at least six (6) months prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

Any renewal of Service is subject to the Financial ~~Information and Security~~Assurances provisions in Article 10 of the General Terms and Conditions

8.0 APPLICATION FOR SERVICE

8.1 Applications for Service under this Rate Schedule CO_2 shall be in such form as Company may prescribe from time to time.

9.0 GENERAL TERMS AND CONDITIONS

The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule CO_2 are applicable to Rate Schedule CO_2 to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

2.3 Excess CO_2 delivered to the System is not expected to exceed 600 $10^3m^3/d$ (21.3 MMcf/d). Should Company expect that the contracted volume of Excess CO_2 under the Service will exceed 600 $10^3m^3/d$ (21.3 MMcf/d), Company shall provide notice to the Toll, Tariff, Facilities & Procedures Committee ("TTFP") to initiate a review of the CO_2 Management Service to determine the effect of Service on Customers, producers and end-users. Within 90 days of the commencement of the TTFP review, Company on behalf of the TTFP will advise the Board of any required changes to the Service to ensure the Service will not have an impact on the commingled gas stream that has unintended consequential and a material adverse economic consequence on Customers, producers or end-users. In the event that the TTFP can not reach resolution on issues related to the CO_2 Management Service, Company on behalf of the TTFP will provide a report to the Board identifying such issues and seek Board direction. Company will continue to operate, offer and contract for the CO_2 Management Service during this time.

2.4 Should the contracted volume of Excess CO_2 under the Service continue to increase beyond 600 $10^3m^3/d$ (21.3 MMcf/d), the TTFP will conduct similar reviews at increments of 100 $10^3m^3/d$ (3.6 MMcf/d) unless otherwise agreed to by the TTFP or directed by the Board.

3.0 CO_2 RECEIPT ZONE

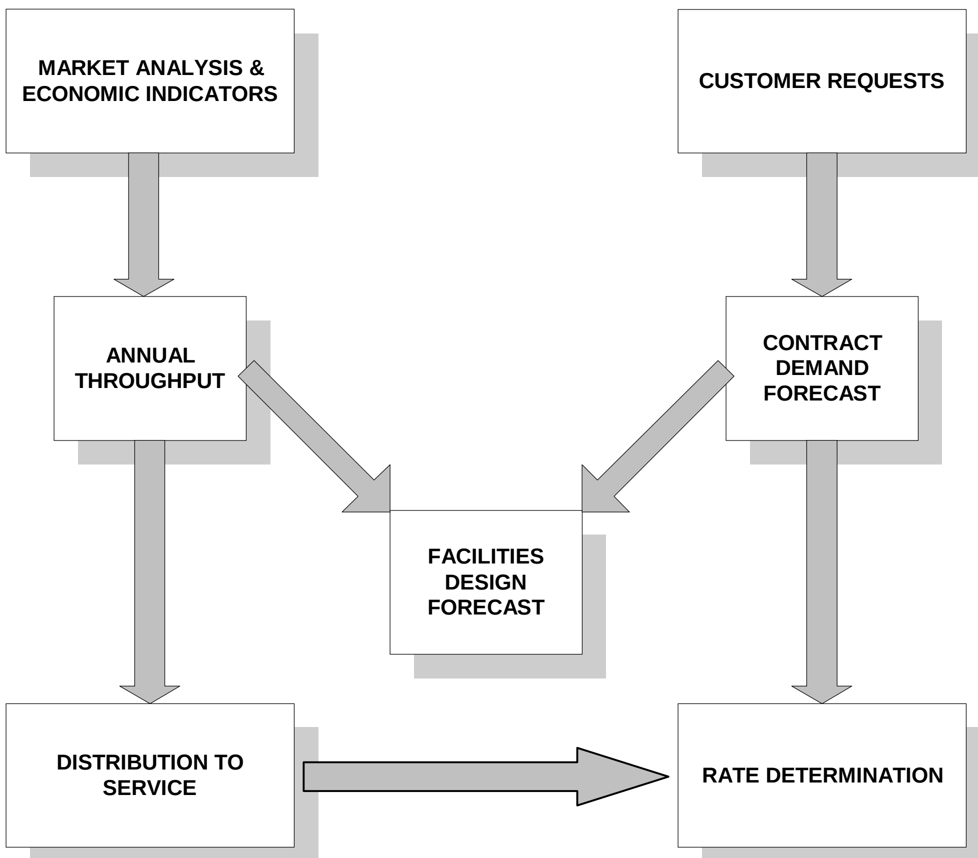
3.1 If, while providing the CO_2 Management Service, natural gas volumes containing CO_2 greater than 2% are expected to be delivered to a CPO and Company is satisfied that the CPO or its customers would experience a demonstrated material adverse impact, Company may designate a CO_2 Receipt Zone ("CRZ") or arrange another alternative with the CPO at an Alberta Delivery Point or an Extraction Delivery Point. ~~A CPO is any party that has signed a Facility Connection Service agreement with Company.~~ A material adverse impact is defined as a quantifiable cost to an industrial process (that uses natural gas as a feedstock) that would experience a material efficiency degradation or detriment of material economic consequence resulting from the receipt of gas containing CO_2

4.0 CONTRACT DEMAND QUANTITY AND THROUGHPUT

4.1 OVERVIEW

In this Section, NGTL provides Contract Demand Quantity and Throughput information for the purposes of determining the 2005 illustrative rates, tolls and charges in Section 5. The following flow chart outlines the interrelationship between Firm Transportation Contract Demand, Annual Throughput, the Facilities Design Forecast, and rate determination.

Figure 4-1



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

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

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

4.2 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.

4.2.1 Firm Transportation Receipt Point Contract Demand

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

1. New Receipt Point Contract Demand – Tables 4.2-1 and 4.2-2 include the estimated quantity of new Firm Transportation contracts during 2005.

2. The non-renewal of Receipt Point Contract Demand – The Gas Transportation Tariff requires customers to provide renewal commitments one year prior to the expiration of a contract. Contract renewals are known up until the end of December 2005. Tables 4.2-1 and 4.2-2 include the non-renewal information.

The total Receipt Point Contract Demand illustrated in Table 4.2-1 shows a decrease from 256.5 $10^6m^3/d$ (9.11 Bcf/d) at the beginning of the year to 255.4 $10^6m^3/d$ (9.06 Bcf/d) at the end of the 2005. The 2005 average Receipt Point Contract Demand, which is calculated as an average of twelve monthly forecasts, is forecast to be 258.9 $10^6m^3/d$ (9.19 Bcf/d). The monthly forecast detail used to calculate the 2005 average Receipt

Point Contract Demand forecast is shown in Table 4.2-2. Table 4.2-1 also includes figures for 2003 and 2004.

Table 4.2-1[1]
2003-2005 Firm Transportation Receipt Point Contract Demand

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

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

Table 4.2-2[1]

2005 Monthly Firm Transportation Receipt Point Contract Demand
(Bcf/d)

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

(10^6 m^3/d)

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

Note:

1. Numbers may not add due to rounding.

4.2.2 Firm Transportation Export Delivery Point Contract Demand

The Export Delivery Point Contract Demand is determined after considering the total quantity signed by customers under Firm Transportation agreements for the 2004/05 and 2005/06 Gas Years, and adjustments for any new and expiring Contract Demand forecast to occur during 2005. Components of the total 2005 Export Delivery Point Contract Demand of 228.1 $10^6m^3/d$ (8.10 Bcf/d) are shown in Table 4.2-3. Figures are also included for 2003 and 2004. The monthly forecast detail used to calculate the 2005 average Export Delivery Point Contract Demand forecast is shown in Table 4.2-4.

Table 4.2-3[1]
2003-2005 Firm Transportation Export Delivery Point Contract Demand

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

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

Table 4.2-4[1]

2005 Monthly Firm Transportation Export Delivery Point Contract Demand

(Bcf/d)

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

Monthly Average (Start of Month) 8.10

(10^6 m^3/d)

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

Monthly Average (Start of Month) 228.1

Note:

1. Numbers may not add due to rounding.

4.3 ANNUAL THROUGHPUT

4.3.1 Background

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

- Empress border, which connects with TransCanada's Mainline system and supplies gas to Canadian markets east of Alberta, the U.S. Midwest and U.S. Northeast markets;

- McNeill border, which connects with Foothills Pipe Lines (Sask.) Ltd., which, in turn, connects to Northern Border Pipeline Company and supplies the U.S. Midwest market;

- Alberta-B.C. border, which connects with TransCanada's B.C. System and supplies southern B.C. markets, and also connects with TransCanada's Gas Transmission Northwest (GTN) pipeline system and supplies the Pacific Northwest and California markets;

- Unity and Cold Lake borders, which connect with TransGas Limited and supply the Saskatchewan market;

- Gordondale and Boundary Lake borders, which connect with the Duke Energy Gas Transmission system and supply the British Columbia and Pacific Northwest markets;

- Alberta-Montana border, which connects with NorthWestern Energy's system and supplies the Montana market; and

- Alberta delivery stations.

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

4.3.2 Throughput by Alberta System Delivery Point

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

Table 4.3-1[1]
Alberta System Throughput Forecast

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

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

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

4.3.3 Distribution of 2005 Annual Throughput to Services

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

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

The various Firm and Interruptible service options available to customers combined with market volatility make it difficult to accurately forecast the utilization of these services. The forecast distribution of throughput by service type shown in Tables 4.3-2 and 4.3-3 is based upon historical use, trend analysis, and NGTL's judgment of its customers' use of these services. The throughput numbers shown below correspond to the 2005 calendar year. Throughput numbers used for calculating transportation rates are based on volumes forecast for the 12-month period from December 1 to November 30.

Table 4.3-2[1]

2005 Receipt Throughput by Service

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

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

Table 4.3-3[1]

2005 Delivery Throughput by Service

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

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

5.0 2005 RATES, TOLLS AND CHARGES

5.1 RATES, TOLLS AND CHARGES SUMMARY

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

NGTL calculated these rates in accordance with the rate design and contract demand and throughput quantities outlined in Sections 2 and 4, respectively, of this Application, and the 2005 revenue requirement from the 2005-2007 Revenue Requirement Settlement Application filed with the Board on March 21, 2005.

Figure 5.1-1 provides an overview of the rate calculation process.

Table 5.1-1 provides a comparison by service type between the proposed 2005 rates and the final 2004 rates. The differences are primarily due to the decrease in revenue requirement from 2004 to 2005.

Table 5.1-2 (including Attachments 1 and 2) contains the proposed rates based on a January 1 implementation date. NGTL will, as required, revise these rates, tolls and charges through a compliance filing to reflect the Board's decisions on the 2005-2007 Revenue Requirement Settlement Application and this Application. NGTL recommends an implementation date for final rates, tolls and charges on the first day of the month at least 30 days, but no more than 60 days, after the date the Board renders a decision on the compliance filing.

5.2 ILLUSTRATIVE 2005 RATES, TOLLS AND CHARGES

Figure 5.1-1 - 2005 Illustrative Rate Calculation

TOTAL REVENUE REQUIREMENT	$1,160.0 Million

MINUS

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

EQUALS

TRANSPORTATION REVENUE REQUIREMENT	$1,137.6 Million

MINUS

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

*Revenues adjusted to account for NGTL's contribution.

MINUS

OTHER TRANSPORTATION REVENUE

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

*Revenues adjusted to account for Alternate Access.

EQUALS

FIRM TRANSPORTATION REVENUE REQUIREMENT	$869.1 Million

Figure 5.1-1 cont'd. – 2005 Illustrative Rate Calculation

FIRM TRANSPORTATION REVENUE REQUIREMENT $869.1 Million

DIVIDED BY

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

EQUALS

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

MULTIPLIED BY

RECEIPT CONTRACT DEMAND

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

EQUALS

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT

$452.8 Million

MULTIPLIED BY

DELIVERY CONTRACT DEMAND

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

EQUALS

FIRM TRANSPORTATION DELIVERY REVENUE REQUIREMENT

$416.3 Million

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT $452.8 Million

ALLOCATE TO EACH RECEIPT POINT

RECEIPT TRANSPORTATION REVENUE

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

Table 5.1-1
Comparison of 2004 and 2005 Illustrative Rates, Tolls and Charges

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

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

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

TABLE 5.1-2 ILLUSTRATIVE 2005 RATES, TOLLS & CHARGES

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

TABLE 5.1-2 ATTACHMENT 1

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

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1122	BANTRY NORTH	81.10	89.21	3.06
1398	BAPTISTE	251.21	276.33	9.49
1339	BAPTISTE SOUTH	253.95	279.35	9.59
1497	BARICH	253.95	279.35	9.59
1329	BASHAW	190.99	210.09	7.22
1393	BASHAW B	190.86	209.95	7.21
1330	BASSANO SOUTH	90.52	99.57	3.42
1794	BASSANO SOUTH 2	90.64	99.70	3.42
2761	BASSET LAKE	253.95	279.35	9.59
2085	BASSET LAKE S.	253.95	279.35	9.59
2066	BASSET LAKE W.	253.95	279.35	9.59
1197	BAXTER LAKE	253.95	279.35	9.59
1334	BAXTER LAKE B	253.95	279.35	9.59
1382	BAXTER LAKE NW	253.95	279.35	9.59
1231	BAXTER LAKE S.	253.95	279.35	9.59
1198	BAXTER LAKE W.	253.95	279.35	9.59
2143	BAY TREE	253.95	279.35	9.59
2222	BEAR CANYON W.	223.10	245.41	8.43
2132	BEAR RIVER	253.95	279.35	9.59
1459	BEAUVALLON	253.95	279.35	9.59
1089	BELLIS	171.32	188.45	6.47
1675	BELLIS SOUTH	169.12	186.03	6.39
2043	BELLOY	231.78	254.96	8.76
2105	BELLOY WEST	196.07	215.68	7.41
1720	BELTZ LAKE	133.28	146.61	5.04
1264	BENALTO WEST	123.02	135.32	4.65
2177	BENBOW SOUTH	166.48	183.13	6.29
1274	BENTON WEST	99.84	109.82	3.77
1604	BERRY CREEK S.	110.85	121.94	4.19
1085	BERRY-CAROLSIDE	81.10	89.21	3.06
1157	BIG BEND	253.95	279.35	9.59
1225	BIG BEND EAST	253.95	279.35	9.59
2175	BIG PRAIRIE	253.95	279.35	9.59
1835	BIGKNIFE CREEK	114.18	125.60	4.31
2176	BIGORAY RIVER	141.07	155.18	5.33
1002	BINDLOSS N. #1	81.10	89.21	3.06
1001	BINDLOSS SOUTH	81.10	89.21	3.06
1474	BINDLOSS WEST	151.15	166.27	5.71
2256	BISON LAKE	253.95	279.35	9.59
3446	BITTERN LAKE SL	253.95	279.35	9.59
1616	BLOOD IND CK E.	86.22	94.84	3.26
1505	BLOOD INDIAN CK	81.10	89.21	3.06
1779	BLOOR LAKE	185.84	204.42	7.02
1511	BLUE JAY	253.95	279.35	9.59
2704	BLUE RAPIDS	98.13	107.94	3.71
3471	BLUE RIDGE E SL	184.11	202.52	6.96

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

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

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10^{3}m^3)	FT-RN Demand Rate per Month ($/10^{3}m^3)	IT-R Rate per Day ($/10^{3}m^3)
1434	CHISHOLM MILLS	253.95	279.35	9.59
1322	CHOICE	253.95	279.35	9.59
1323	CHOICE B	253.95	279.35	9.59
1712	CHRISTINA LAKE	253.95	279.35	9.59
1679	CHUMP LAKE	253.95	279.35	9.59
1535	CLANDONALD	253.95	279.35	9.59
2070	CLARK LAKE	148.15	162.97	5.60
2063	CLEAR HILLS	228.10	250.91	8.62
2250	CLEAR HILLS N.	195.32	214.85	7.38
2764	CLEAR PRAIRIE	253.95	279.35	9.59
3008	CLEARDALE	249.91	274.90	9.44
1454	CLYDE	253.95	279.35	9.59
1803	CLYDE NORTH	253.95	279.35	9.59
6007	CLYDEN	253.95	279.35	9.59
3883	COALDALE JCT	81.10	89.21	3.06
5402	COALDALE S. B	102.15	112.37	3.86
3884	COALDALE S. JCT	81.10	89.21	3.06
1612	COATES LAKE	209.30	230.23	7.91
2735	CODESA	240.59	264.65	9.09
2152	CODNER	117.91	129.70	4.45
1417	COLD LAKE BDR	253.95	279.35	9.59
2003	COLEMAN	81.10	89.21	3.06
3052	COLEMAN SALES	81.10	89.21	3.06
1624	CONKLIN	253.95	279.35	9.59
1634	CONKLIN WEST	253.95	279.35	9.59
3904	CONKLIN WEST INTERCHANGE INTERCONNECTION	253.95	279.35	9.59
1713	CONN LAKE	253.95	279.35	9.59
1635	CONTRACOSTA E.	198.60	218.46	7.50
1614	CONTRACOSTA LK	148.60	163.46	5.61
2736	COPTON CREEK	215.15	236.67	8.13
1763	CORNER LAKE #2	253.95	279.35	9.59
6010	CORRIGAL LAKE	253.95	279.35	9.59
1697	CORRIGALL LAKE	253.95	279.35	9.59
1667	COTTONWOOD CRK	253.95	279.35	9.59
1028	COUNTESS	81.10	89.21	3.06
1015	COUNTESS MAKEPE	84.58	93.04	3.20
2296	COUNTESS S. #2	81.10	89.21	3.06
1287	COUNTESS WEST	136.76	150.44	5.17
1963	COUSINS B&C SALES	118.02	129.82	4.46
1433	COUSINS WEST	118.35	130.19	4.47
1112	CRAIGEND EAST	235.74	259.31	8.91
1320	CRAIGEND NORTH	253.95	279.35	9.59
1148	CRAIGEND SOUTH	253.95	279.35	9.59
1541	CRAIGMYLE	224.98	247.48	8.50
1583	CRAIGMYLE EAST	253.95	279.35	9.59
1686	CRAMMOND	81.10	89.21	3.06

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

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

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

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($\$/10^3m^3$)	FT-RN Demand Rate per Month ($\$/10^3m^3$)	IT-R Rate per Day ($\$/10^3m^3$)
1576	HADDOCK	146.27	160.90	5.53
1589	HADDOCK NORTH	150.86	165.95	5.70
1636	HADDOCK SOUTH	173.65	191.02	6.56
2086	HAIG RIVER	253.95	279.35	9.59
2064	HAIG RIVER EAST	253.95	279.35	9.59
2127	HAIG RIVER N.	253.95	279.35	9.59
1230	HAIRY HILL	180.16	198.18	6.81
1391	HALKIRK	124.67	137.14	4.71
1834	HALKIRK NORTH#2	94.55	104.01	3.57
3915	HAMILTON LAKE SUMMARY	223.45	245.80	8.44
1291	HAMLIN	253.95	279.35	9.59
6003	HANGINGSTONE	253.95	279.35	9.59
1182	HANNA	93.58	102.94	3.54
1444	HARDISTY	226.84	249.52	8.57
1166	HARMATTAN-ELKTN	81.10	89.21	3.06
2145	HARO RIVER N.	253.95	279.35	9.59
2766	HARPER CREEK	190.27	209.30	7.19
1850	HARTELL SOUTH	81.10	89.21	3.06
1709	HASTINGS COULEE	154.62	170.08	5.84
1418	HATTIE LAKE N.	253.95	279.35	9.59
2126	HAY RIVER	253.95	279.35	9.59
2278	HAY RIVER SOUTH	253.95	279.35	9.59
1603	HAYS	182.91	201.20	6.91
2140	HEART RIVER	253.95	279.35	9.59
1439	HEISLER	105.00	115.50	3.97
1523	HELINA	253.95	279.35	9.59
2174	HENDERSON CK SE	243.59	267.95	9.20
2164	HENDERSON CREEK	239.30	263.23	9.04
1673	HERMIT LAKE	208.21	229.03	7.87
3611	HERMIT LAKE SLS	208.31	229.14	7.87
2059	HINES CREEK	253.95	279.35	9.59
2219	HINES CREEK W.	253.95	279.35	9.59
1161	HOLDEN	170.44	187.48	6.44
1528	HOOLE	253.95	279.35	9.59
1411	HORBURG	99.56	109.52	3.76
2047	HOTCHKISS	253.95	279.35	9.59
2065	HOTCHKISS EAST	253.95	279.35	9.59
2094	HOTCHKISS NE B	253.95	279.35	9.59
2095	HOTCHKISS NE C	253.95	279.35	9.59
2054	HOTCHKISS NORTH	246.92	271.61	9.33
3920	HOUSE RIVER INTERCONNECTION	253.95	279.35	9.59
2169	HOWARD CREEK E.	253.95	279.35	9.59
1207	HUDSON	155.67	171.24	5.88
1413	HUDSON WEST	129.14	142.05	4.88
1854	HUGHENDEN EAST	199.85	219.84	7.55
1859	HUMMOCK LAKE	102.56	112.82	3.87

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($/10³m³)	FT-RN Demand Rate per Month ($/10³m³)	IT-R Rate per Day ($/10³m³)
2277	HUNT CREEK	253.95	279.35	9.59
2751	HUNT CREEK #2	253.95	279.35	9.59
1436	HUSSAR NORTH	81.10	89.21	3.06
1016	HUSSAR-CHANCELL	81.10	89.21	3.06
1142	HUXLEY	112.95	124.25	4.27
1591	HUXLEY EAST	223.82	246.20	8.46
1241	HYLO	253.95	279.35	9.59
1357	HYLO SOUTH	253.95	279.35	9.59
1479	HYTHE	219.20	241.12	8.28
1277	IDDESLEIGH S.	84.67	93.14	3.20
1678	INDIAN LAKE	139.56	153.52	5.27
1717	INDIAN LAKE #2	139.00	152.90	5.25
3857	INLAND INTERCONNECTION	148.72	163.59	5.62
1685	IPIATIK LAKE	253.95	279.35	9.59
1441	IRISH	253.95	279.35	9.59
1593	IRON SPRINGS	81.10	89.21	3.06
1569	IROQUOIS CREEK	169.90	186.89	6.42
1201	IRVINE	147.61	162.37	5.58
1407	ISLAND LAKE	212.89	234.18	8.04
1700	ISLAND LAKE #2	212.82	234.10	8.04
1694	JACKFISH CREEK	253.95	279.35	9.59
2723	JACKPOT CREEK	253.95	279.35	9.59
2146	JACKSON CREEK	86.17	94.79	3.26
3860	JANUARY CREEK INTERCONNECTION	128.31	141.14	4.85
1163	JARROW	251.51	276.66	9.50
1159	JARROW SOUTH	236.45	260.10	8.93
1281	JARROW WEST	253.95	279.35	9.59
1143	JENNER EAST	81.10	89.21	3.06
1099	JENNER WEST	81.10	89.21	3.06
1385	JENNER WEST B	81.10	89.21	3.06
1167	JOFFRE	164.53	180.98	6.22
3864	JOFFRE #2 AND #3 SALES INTERCONNECTION	111.13	122.24	4.20
2267	JONES LAKE	195.89	215.48	7.40
2279	JONES LAKE #2	196.07	215.68	7.41
2272	JONES LAKE EAST	212.55	233.81	8.03
2241	JONES LAKE N.	227.74	250.51	8.60
2087	JOSEPHINE	245.89	270.48	9.29
2022	JUDY CREEK	245.66	270.23	9.28
2036	JUMPING POUND W	81.10	89.21	3.06
1811	KAKWA	195.75	215.33	7.40
1462	KARR	154.03	169.43	5.82
2013	KAYBOB	169.77	186.75	6.41
2027	KAYBOB 11-36	167.78	184.56	6.34
2020	KAYBOB SOUTH	156.09	171.70	5.90
2035	KAYBOB SOUTH #3	133.44	146.78	5.04
2053	KEG RIVER	253.95	279.35	9.59

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

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

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

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

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 ($\$/10^3m^3$)
1728	PARADISE VALLEY	253.95	279.35	9.59
1853	PARKER CREEK	253.95	279.35	9.59
1665	PARSONS LAKE	253.95	279.35	9.59
2089	PASS CREEK	146.43	161.07	5.53
2168	PASS CREEK WEST	140.59	154.65	5.31
2260	PASTECHO RIVER	253.95	279.35	9.59
1278	PATRICIA	81.10	89.21	3.06
1289	PATRICIA WEST	90.33	99.36	3.41
3804	PEMBINA INTERCONNECTION	96.46	106.11	3.64
2185	PEMBINA WEST	107.39	118.13	4.06
1180	PENHOLD	86.40	95.04	3.26
1607	PENHOLD WEST	121.62	133.78	4.60
2280	PETE LAKE	241.21	265.33	9.11
2247	PETE LAKE SOUTH	192.93	212.22	7.29
1714	PICHE LAKE	253.95	279.35	9.59
1610	PICTURE BUTTE	173.15	190.47	6.54
2046	PIONEER	116.52	128.17	4.40
2088	PIONEER EAST	152.99	168.29	5.78
1739	PIPER CREEK	118.71	130.58	4.49
1797	PITLO	253.95	279.35	9.59
1110	PLAIN LAKE	226.12	248.73	8.54
1710	PLEASANT WEST	253.95	279.35	9.59
1858	POE	115.62	127.18	4.37
2173	POISON CREEK	160.36	176.40	6.06
3879	PRIDDIS INTERCONNECTION	81.10	89.21	3.06
1246	PRINCESS EAST	81.10	89.21	3.06
1327	PRINCESS SOUTH	81.10	89.21	3.06
1183	PRINCESS WEST	81.10	89.21	3.06
1010	PRINCESS-DENHAR	81.10	89.21	3.06
1022	PRINCESS-IDDESL	81.10	89.21	3.06
2153	PROGRESS	202.02	222.22	7.63
2191	PROGRESS EAST	208.03	228.83	7.86
1304	PROSPERITY	229.54	252.49	8.67
1211	PROVOST MONITOR	223.03	245.33	8.43
1003	PROVOST NORTH	132.84	146.12	5.02
1013	PROVOST SOUTH	143.52	157.87	5.42
1045	PROVOST WEST	197.26	216.99	7.45
1038	PROVOST-KESSLER	214.78	236.26	8.11
1601	QUEENSTOWN	185.36	203.90	7.00
2026	QUIRK CREEK	81.10	89.21	3.06
1741	RABBIT LAKE	253.95	279.35	9.59
2201	RAINBOW LAKE S.	253.95	279.35	9.59
1106	RAINIER	81.10	89.21	3.06
1380	RAINIER S.W.	87.34	96.07	3.30
1378	RAINIER SOUTH	115.71	127.28	4.37
1282	RALSTON	95.09	104.60	3.59

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

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

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

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

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

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

TABLE 5.1-2 ATTACHMENT 2

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