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Reference: Appendix 2, TQM Evidence, p.2 A5.

Preamble: The evidence lists two groups of companies or projects as comparables. There are negotiated agreements or settlements for companies in both groups.

Request:

(a) Please provide the negotiated agreements or settlements that are current for each company or project in both sample groups.

(b) What other potential companies or pipeline projects were considered for comparison and why were they excluded?

(c) What other pipeline projects is TQM or its owners TransCanada and Gaz Metro aware of that were excluded and why?

(d) What was the ROE as determined by the NEB formula in 1996 and 1997? What ATWACCs result from the combination of those ROEs with a 30% equity ratio?

(e) Using the approach of Dr. Vilbert, what is the equivalent percentage ROE on 40% equity of (i) a 12% ROE on 30% and of (ii) an 11.25% ROE on 30% equity? What is the equivalent ROE on 30% equity of (i) an 8.71% ROE on 40% and of (ii) an 11% ROE on 40% equity? Please provide the calculations.

Response:

(a) Please refer to Attachment CAPP 39(a).

(b) Other pipelines and utilities were considered, including:

- Union Gas – excluded due to circularity of ROE formula;
- Enbridge Gas Distribution - excluded due to circularity of ROE formula;
- Spectra (Westcoast) - excluded due to circularity of ROE formula;
- ATCO Pipelines - excluded due to circularity of ROE formula;

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- NGTL - excluded due to circularity of ROE formula;
- Gateway – excluded as the project was put on hold; and
- Mackenzie Valley Pipeline – insufficient information.

(c) No other known major Canadian pipeline projects for which return information was available were excluded.

(d) The NEB Formula ROE for 1996 was 11.25% and for 1997 10.67%. The ATWACCs for 1996 and 1997 (assuming a 3.75% cost of debt) are 6.02% and 5.83% respectively at a 30% equity ratio.

(e) The ATWACC method follows the formula:

*Total Return = (ROE * Equity Ratio) + (After-Tax Cost of Debt * Debt Ratio)*

All calculations are based on an after-tax cost of debt of 3.75%.

- A 12% ROE on 30% equity yields an ATWACC of 6.23%. To obtain the same ATWACC at a 40% equity, the ROE must be 9.95%:
- An 11.25% ROE on 30% equity yields an ATWACC of 6.00%. To obtain the same ATWACC at a 40% equity, the ROE must be 9.38%:
- An 8.71% ROE on 40% equity yields an ATWACC of 5.73%. To obtain the same ATWACC at a 30% equity, the ROE must be 10.35%:
- An 11% ROE on 40% equity yields an ATWACC of 6.65%. To obtain the same ATWACC at a 30% equity, the ROE must be 13.42%:

Maritimes & Northeast Pipeline

MARITIMES & NORTHEAST PIPELINE ("M&NP")

2007 TOLL SETTLEMENT

1. Term

1.1 This settlement ("Settlement") covers the calendar year 2007 ("Settlement Period").

2. Revenue Requirement

2.1 The agreed to revenue requirement for 2007 is ($000's):

		2007
1.	O&M Expenses	10,000
2.	Toll Hearing Costs	0
3.	NEB Cost Recovery	750
4.	Return on Rate Base	58,392
5.	Depreciation Expense	42,652
6.	Municipal & Other Taxes (Non-Income)	17,076
7.	Income Taxes	23,677
8.	IT & Other Revenue	(6,300)
9.	Deferrals	*
10.	Total Revenue Requirement *	146,246

* Total Revenue Requirement will be adjusted for prior year deferral account balances.

2.2 M&NP shall continue to allow 100 percent of its bank debt to float for 2007. For tolling purposes, M&NP will utilize a floating debt rate based on a 90-day T-Bill forecast rate of 4.20 percent plus applicable spreads. Note that a deferral account will be in effect for this account for 2007.

3. Toll

3.1 M&NP's MN365 toll for the Settlement Period is $0.6843/GJ ($0.7219/MMBtu) This toll will be adjusted during 2007 by disposing of the prior year's deferral account balances, consisting of variances between forecast amounts and financial statement actual amounts.

4. Deferral Accounts

4.1 The following deferral accounts will be maintained throughout the Settlement Period:

(a) IT/Other Revenue;
(b) Toll Hearing Costs;
(c) Interest Expense;
(d) Income and Large Corporation Taxes;
(e) Municipal and Other Taxes;
(f) Provincial Discounts; and
(g) Demand Determinants.

4.2 **IT/Other Revenue:** This deferral account will be utilized to true up to the IT/Other Revenues once these have been finalized. IT/Other Revenue has been estimated at $6.3 million for the prospective calculation of the 2007 cost of service. Pursuant to the current M&NP 2004-06 Tolls Settlement, any variance in IT/Other Revenue from $3.5 million will be applied to the 2007 cost of service. During 2007, any variance between the actual IT/Other Revenue and $6.3 million will be charged or credited to the 2008 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.3 **Toll Hearing Costs:** This deferral account will be utilized to true up to the actual toll hearing costs once these have been finalized. Toll hearing costs have been estimated at zero for the prospective calculation of the 2007 cost of service. Pursuant to the current M&NP 2004-06 Tolls Settlement, any variance in 2006 toll hearing costs from zero will be applied to the 2007 cost of service. During 2007, any variance between the actual toll hearing costs and zero will be charged to the 2008 cost of service. Carrying charges incurred on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.4 **Interest Expense:** This deferral account will be utilized to true up to the actual interest expense once this has been finalized. M&NP will allow 100 percent of M&NP's bank debt to continue to float for 2007. All variances in interest costs during 2007 will be deferred to the 2008 cost of service. Pursuant to the current M&NP 2004-06 Tolls Settlement, any variance in 2006 interest costs will be applied to the 2007 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital. For clarity, "interest rate variances" are the difference between: (i) the actual debt cost obtained by keeping the bank debt floating, and (ii) debt costs that would have otherwise occurred utilizing 6.5338%.

4.5 **Income and Large Corporation Taxes:** This deferral account will be utilized to true up to the actual income and large corporation taxes once these have been finalized. Income and large corporation Taxes have been estimated at $23.7 million for the prospective calculation of the 2007 cost of service. Pursuant to the current M&NP 2004-06 Tolls Settlement, any variance in 2006 income and large corporation taxes from $16.7 million will be applied to the 2007 cost of service. During 2007, any variance between the actual income and large corporation taxes and the amounts estimated will be charged or credited to the 2008 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.6 **Municipal & Other Taxes:** This deferral account will be utilized to true up to the actual municipal and other taxes once these have been finalized. Municipal and other taxes have been estimated at $17.1 million for the prospective calculation of the 2007 cost of service. Pursuant to the current M&NP 2004-06 Tolls Settlement, any variance in 2006 municipal and other taxes from $17.4 million will be applied to the 2007 cost of service. During 2007, any variance between the actual municipal and other taxes and the amounts estimated will be charged or credited to the 2008 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.7 **Provincial Discounts:** This deferral account will continue to operate to account for provincial discounts that are to apply in the Province of Nova Scotia during 2007.

4.8 **Demand Determinants:** This deferral account will be utilized to true up to the actual demand determinants and associated cost of service once these have been finalized. Demand determinants have been estimated at 554,992 MMBtu/d for the prospective calculation of the 2007 tolls. Pursuant to the current M&NP 2004-06 Tolls Settlement, any variance in 2006 demand determinants from 554,992 MMBtu/d will be applied to the 2007 cost of service. During 2007, revenues/shortfalls attributable to any variances between the actual and forecast demand determinants and the associated cost of service and the original amounts estimated will be either charged or credited to the 2008 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

5. Key Determinants Changed

5.1 During the Settlement Period, M&NP's key determinants of depreciation, capital structure and allowed return on equity will change. M&NP's revenue requirement over the Settlement Period is based on a depreciation rate of 4.25%, a deemed equity of 29.27% and an allowed return on equity of 12%.

6. General

6.1 This Settlement represents a balancing of interests by the TTWG members and therefore no single component can be said to be acceptable to any member independent of the entire Settlement. All components of the Settlement are linked and must be treated as a "package" deal.

6.2 The members agree to the terms of this Settlement for the Settlement Period. However, this Settlement sets no precedent nor shall it prejudice any position the TTWG members may take in any other future proceeding regarding any of the matters addressed in this Settlement in any future period beyond the Settlement Period.

6.3 This Settlement is subject to approval by the National Energy Board.

MARITIMES & NORTHEAST PIPELINE ("M&NP")

2008 TOLL SETTLEMENT

1. Term

1.1 This settlement ("Settlement") covers the calendar year 2008 ("Settlement Period").

2. Revenue Requirement

2.1 The agreed to revenue requirement for 2008 is ($000's):

		2008
1.	O&M Expenses	10,000
2.	Toll Hearing Costs	0
3.	NEB Cost Recovery	750
4.	Return on Rate Base	55,495
5.	Depreciation Expense	45,425
6.	Municipal & Other Taxes (Non-Income)	16,026
7.	Income Taxes	24,944
8.	IT & Other Revenue	(5,000)
9.	Deferrals	*
10.	Total Revenue Requirement *	147,640

* Total Revenue Requirement will be adjusted for prior year deferral account balances.

2.2 M&NP shall continue to allow 100 percent of its bank debt to float for 2008. For tolling purposes, M&NP will utilize a floating debt rate based on a 90-day T-Bill forecast rate of 4.20 percent plus applicable spreads. Note that a deferral account will be in effect for this account for 2008.

3. Toll

3.1 M&NP's MN365 toll for the Settlement Period is $0.7317/GJ ($0.7720/MMBtu) This toll will be adjusted during 2008 by disposing of the prior year's deferral account balances, consisting of variances between forecast amounts and financial statement actual amounts.

4. <u>Deferral Accounts</u>

4.1 The following deferral accounts will be maintained throughout the Settlement Period:

(a) IT/Other Revenue;
(b) Toll Hearing Costs;
(c) Interest Expense;
(d) Income and Large Corporation Taxes;
(e) Municipal and Other Taxes;
(f) Provincial Discounts; and
(g) Demand Determinants.

4.2 **IT/Other Revenue:** This deferral account will be utilized to true up to the IT/Other Revenues once these have been finalized. IT/Other Revenue has been estimated at $5.0 million for the prospective calculation of the 2008 cost of service. Pursuant to the current M&NP 2007 Tolls Settlement, any variance in IT/Other Revenue from $6.3 million will be applied to the 2008 cost of service. During 2008, any variance between the actual IT/Other Revenue and $5.0 million will be charged or credited to the 2009 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.3 **Toll Hearing Costs:** This deferral account will be utilized to true up to the actual toll hearing costs once these have been finalized. Toll hearing costs have been estimated at zero for the prospective calculation of the 2008 cost of service. Pursuant to the current M&NP 2007 Tolls Settlement, any variance in 2007 toll hearing costs from zero will be applied to the 2008 cost of service. During 2008, any variance between the actual toll hearing costs and zero will be charged to the 2009 cost of service. Carrying charges incurred on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.4 **Interest Expense:** This deferral account will be utilized to true up to the actual interest expense once this has been finalized. M&NP will allow 100 percent of M&NP's bank debt to continue to float for 2008. All variances in interest costs during 2008 will be deferred to the 2009 cost of service. Pursuant to the current M&NP 2007 Tolls Settlement, any variance in 2007 interest costs will be applied to the 2008 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital. For clarity, "interest rate variances" are the difference between: (i) the actual debt cost obtained by keeping the bank debt floating, and (ii) debt costs that would have otherwise occurred utilizing 6.6025%.

4.5 **Income and Large Corporation Taxes:** This deferral account will be utilized to true up to the actual income and large corporation taxes once these have been finalized. Income and large corporation Taxes have been estimated at $24.9 million for the prospective calculation of the 2008 cost of service. Pursuant to the current M&NP 2007 Tolls Settlement, any variance in 2007 income and large corporation taxes from $23.7 million will be applied to the 2008 cost of service. During 2008, any variance between the actual income and large corporation taxes and the amounts estimated will be charged or credited to the 2009 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.6 **Municipal & Other Taxes:** This deferral account will be utilized to true up to the actual municipal and other taxes once these have been finalized. Municipal and other taxes have been estimated at $16.0 million for the prospective calculation of the 2008 cost of service. Pursuant to the current M&NP 2007 Tolls Settlement, any variance in 2007 municipal and other taxes from $17.1 million will be applied to the 2008 cost of service. During 2008, any variance between the actual municipal and other taxes and the amounts estimated will be charged or credited to the 2009 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

4.7 **Provincial Discounts:** This deferral account will continue to operate to account for provincial discounts that are to apply in the Province of Nova Scotia during 2008.

4.8 **Demand Determinants:** This deferral account will be utilized to true up to the actual demand determinants and associated cost of service once these have been finalized. Demand determinants have been estimated at 522,533 MMBtu/d for the prospective calculation of the 2008 tolls. Pursuant to the current M&NP 2007 Tolls Settlement, any variance in 2007 demand determinants from 554,992 MMBtu/d will be applied to the 2008 cost of service. During 2008, revenues/shortfalls attributable to any variances between the actual and forecast demand determinants and the associated cost of service and the original amounts estimated will be either charged or credited to the 2009 cost of service. Carrying charges incurred or interest gained on any balances deferred will be calculated based on M&NP's weighted average cost of capital.

5. Key Determinants Changed

5.1 During the Settlement Period, M&NP's key determinants of depreciation, capital structure and allowed return on equity will change. M&NP's revenue requirement over the Settlement Period is based on a depreciation rate of 4.5%, a deemed equity of 31.18% and an allowed return on equity of 11.66%.

6. General

6.1 This Settlement represents a balancing of interests by the TTWG members and therefore no single component can be said to be acceptable to any member independent of the entire Settlement. All components of the Settlement are linked and must be treated as a "package" deal.

6.2 The members agree to the terms of this Settlement for the Settlement Period. However, this Settlement sets no precedent nor shall it prejudice any position the TTWG members may take in any other future proceeding regarding any of the matters addressed in this Settlement in any future period beyond the Settlement Period.

6.3 This Settlement is subject to approval by the National Energy Board.

Alliance Pipeline

TRANSPORTATION SERVICE AGREEMENT
FOR FIRM TRANSPORTATION OF NATURAL GAS
ALLIANCE PIPELINE LIMITED PARTNERSHIP

THIS AGREEMENT made and entered into this _____ day of _______________, 2000,

BETWEEN:

ALLIANCE PIPELINE LIMITED PARTNERSHIP,
formed under the laws of the Province of Alberta
as a limited partnership ("**Transporter**"),

and

____ ("Shipper")

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SCHEDULE B - OPTIONEE

Firm Transportation Service Agreement No. «TSA_No»

TRANSPORTATION SERVICE AGREEMENT
FOR FIRM TRANSPORTATION OF NATURAL GAS
ALLIANCE PIPELINE LIMITED PARTNERSHIP

This TRANSPORTATION SERVICE AGREEMENT FOR FIRM TRANSPORTATION OF NATURAL GAS ("**Transportation Service Agreement**") is made and entered into this ____ day of ____________, 2000, between:

ALLIANCE PIPELINE LIMITED PARTNERSHIP, formed under the laws of the Province of Alberta as a limited partnership ("**Transporter**"),

and

____
("**Shipper**").

Transporter and Shipper are sometimes collectively referred to herein as the "**Parties**" and individually as a "**Party**".

RECITALS:

1. The business of Transporter is the operation of a pipeline (the "**Canadian Pipeline**") to transport Natural Gas from Western Canada to the interconnection of the Canadian Pipeline with the U.S. Pipeline on the Canada-United States border;

2. The business of Alliance Pipeline L.P. (the "**U.S. Transporter**") is the operation of a pipeline (the "**U.S. Pipeline**") to transport Natural Gas from the point of the interconnection of the U.S. Pipeline with the Canadian Pipeline on the Canada-United States border to the midwestern United States area;

3. Shipper has requested that Transporter transport, and Transporter has agreed to transport volumes of Natural Gas that are tendered by or on behalf of Shipper to Transporter at Receipt Points to the Delivery Point in accordance with and subject to the terms and conditions of this Transportation Service Agreement;

4. Shipper, Shipper's agent or another Person designated by Shipper has entered into agreements with U.S. Transporter for transportation of the volumes of Natural Gas referred to in Recital 3 hereof from the Delivery Point to delivery points on the U.S. Pipeline.

NOW, THEREFORE, in consideration of the premises and mutual covenants and agreements of the Parties herein contained, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Transportation Service Agreement, including the Recitals and Schedules hereto, the following words and phrases have the following meanings:

"**Affiliate**", when used to indicate a relationship with a specific Person, means another Person that directly, or indirectly through one or more intermediaries or otherwise, controls, or is controlled by, or is under common control with such specific Person. A corporation shall be deemed to be an Affiliate of another corporation if one of them is directly or indirectly controlled by the other or if each of them is directly or indirectly controlled by the same Person.

"**Authorities**" means all governmental or regulatory authorities having valid jurisdiction over the Canadian Pipeline or over the facilities and operations of Shipper in Canada, as the case may be and “Authority” means any of them.

"**Authorized Overrun Service**" has the meaning ascribed to it in the Tariff.

"**Canadian Pipeline**" has the meaning ascribed to it in Recital 1 hereof.

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"**Commodity Charge**" has the meaning ascribed to it in the Tariff.

"**Contract Capacity**" or "**Contracted Capacity**" means the daily volume of Natural Gas set out in Schedule A contracted for by Shipper hereunder and for which Shipper has agreed to pay the Demand Charge, the Commodity Charge and, if applicable, the Demand Charge Surcharge in accordance with the terms of this Transportation Service Agreement.

"**Contract Capacities**" or "**Contracted Capacities**" means the aggregate of the daily volumes of Natural Gas subject to all Transportation Service Agreements to which Transporter is a party.

"**Delivery Point**" means the point of interconnection between the Canadian Pipeline and the U.S. Pipeline.

"**Demand Charge**" has the meaning ascribed to it in the Tariff.

"**Demand Charge Surcharge**" has the meaning ascribed to it in the Tariff.

"**Effective Date**" has the meaning ascribed to it in Section 6.1 hereof.

"**Force Majeure**" has the meaning ascribed to it in the Tariff.

"**Fuel Requirement**" has the meaning ascribed to it in the Tariff.

"**Gas**" or "**Natural Gas**" means methane, and such other hydrocarbon constituents, or a mixture of two or more of them, which, in any case, meets the quality specifications of the Tariff.

"**General Terms and Conditions**" has the meaning ascribed to it in the definition of "**Tariff**".

"**Lenders**" means any banks, financial institutions and investors which provide financing for the construction or operation of, the U.S. Pipeline and/or Canadian Pipeline, as well as Transporter's banking advisers.

"**NEB**" means the National Energy Board of Canada established by the *NEB Act* or any replacement or successor regulatory or government authority or authorities having jurisdiction over the approval, licensing, construction, operation or tolls of interprovincial pipelines in natural gas service.

"***NEB Act***" means the *National Energy Board Act* (Canada) as amended from time to time and includes any Canadian federal legislation enacted in replacement thereof.

"**Optionee**" has the meaning ascribed to it in Section 5.2 hereof.

"**Party**" means a party to this Transportation Service Agreement and "Parties" means each of them.

"**Person**" means an individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator or other legal personal representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted.

"**Primary Term**" has the meaning ascribed to it in Section 6.1 hereof.

"**Primary Receipt Point Capacity**" or “Primary Receipt Point Capacities” have the meanings ascribed to them in the Tariff.

"**Receipt Point(s)"** means any one or more of those receipt points described in Section B of Schedule A hereto and any future receipt points notified to Shipper by Transporter.

"**Shipper Default**" has the meaning ascribed to it in Section 8.2 hereof.

"**Shipper's Nomination**" has the meaning ascribed to it in the Tariff.

"**TAC Receipt Point**" has the meaning ascribed to it in the Tariff.

"**Tariff**" means the terms and conditions, in addition to those set out herein, under which Transporter will transport Natural Gas pursuant to this Transportation Service Agreement, as same may from time to time be amended and approved by or filed with the NEB, and is comprised at the date hereof of the Toll Schedule Firm Transportation Service (the "**Toll Schedule Firm Transportation Service**"), and the General Terms and Conditions (the "**General Terms and Conditions**").

"**Transporter Default**" has the meaning ascribed to it in Section 8.1 hereof.

"**U.S. Fuel Requirement**" has the meaning ascribed to it in the Tariff.

"**U.S. Pipeline**" and "**U.S. Transporter**" have the respective meanings ascribed to them in Recital 2 hereof.

Except as specifically provided herein or unless the context otherwise requires, all words and phrases used herein and defined in the Tariff shall have the same meanings ascribed to them in the Tariff.

1.2 Schedules

The following schedules are attached to and made part of this Agreement and each of the terms and provisions thereof, including any revisions thereto made by or necessary to comply with the requirements of any Authorities, are accepted and agreed to by the Parties:

Schedule A - Delivery Point and Receipt Points
Schedule B – Toll Principles
Schedule C - Optionee

ARTICLE 2
REPRESENTATIONS AND WARRANTIES

2.1 **Transporter** represents and warrants that: (a) it is duly organized and validly existing under the laws of the Province of Alberta and has all requisite legal power and authority to execute this Transportation Service Agreement and carry out the terms, conditions and provisions hereof; (b) this Transportation Service Agreement constitutes the valid, legal and binding obligation of Transporter, enforceable in accordance with the terms hereof; (c) there are no actions, suits or proceedings pending or, to Transporter's knowledge, threatened against or affecting Transporter before any court or Authority that might materially adversely affect the ability of Transporter to meet and carry out its obligations under this Transportation Service Agreement; and (d) the execution and delivery by Transporter of this Transportation Service Agreement has been duly authorized by all requisite partnership action.

2.2 Shipper represents and warrants that: (a) it is duly organized and validly existing under the laws of and has all requisite legal power and authority to execute this Transportation Service Agreement and carry out the terms, conditions and provisions hereof; (b) this Transportation Service Agreement constitutes the valid, legal and binding obligation of Shipper, enforceable in accordance with the terms hereof; (c) there are no actions, suits or proceedings pending or, to Shipper's knowledge, threatened against or affecting Shipper before any court or Authority that might materially adversely affect the ability of Shipper to meet and carry out its obligations under this Transportation Service Agreement; and (d) the execution and delivery by Shipper of this Transportation Service Agreement has been duly authorized by all requisite action.

ARTICLE 3
PAYMENT OF DEMAND AND COMMODITY CHARGES

3.1 (a) Shipper shall pay the Demand Charge for the Contracted Capacity in accordance with the Tariff. This obligation of Shipper to pay the Demand Charge shall continue whether or not Natural Gas is actually transported, and is not subject to abatement under any circumstances, except as specifically provided for in the Tariff.

(b) Shipper shall pay the Demand Charge Surcharge in accordance with the Tariff for the Primary Receipt Point Capacities, if any, that it has designated for TAC Receipt Points as Primary Receipt Points in Section C of Schedule A hereto. This obligation of Shipper to pay the Demand Charge Surcharge shall continue whether or not Natural Gas is actually transported from any TAC Receipt Points, and is not subject to abatement under any circumstances, except as specifically provided for in the Tariff.

3.2 Shipper shall pay the Commodity Charge for Shipper's actual deliveries in accordance with the Tariff.

3.3 Notwithstanding any provision of this Transportation Service Agreement, other than Section 10.1, the Parties agree that tolls payable by Shipper for transportation service under this Transportation Service Agreement will be calculated in accordance with the toll principles that are attached hereto as Schedule B, and that such tolls will be set forth in revised Schedule A to the Toll Schedule Firm Transportation Service prepared by Transporter and as filed with or approved by the NEB from time to time.

ARTICLE 4
GAS TO BE TRANSPORTED

4.1 Subject to the provisions of this Transportation Service Agreement:

(a) Transporter shall provide daily transportation service hereunder for Shipper, for the Contracted Capacity, from the Receipt Point(s) identified in Shipper's Nominations to the Delivery Point; and

(b) Transporter may provide daily transportation service hereunder for Shipper, from the Receipt Point(s) identified in Shipper's Nominations to the Delivery Point, in respect of a volume of Natural Gas equal to Shipper's share of the Authorized Overrun Service.

ARTICLE 5
OPTION TO EXTRACT AND PURCHASE LIQUIDS

5.1 Shipper's receipts and deliveries, less the Fuel Requirement, will be balanced on volume and heating value bases at the Delivery Point in accordance with the Tariff.

5.2 Shipper hereby grants to Transporter acting solely in its capacity as agent for the party identified in Schedule C hereto (the "**Optionee**"), the option, exercisable at any time or times, and for any periods during the term of this Transportation Service Agreement, to extract from the commingled Natural Gas transported by Transporter and purchase all natural gas liquids or liquefiable hydrocarbons received by Transporter from Shipper that the Optionee elects to remove or process and hereby relinquishes to Transporter, acting solely in its capacity as agent for the Optionee, all proceeds, profits and losses derived from or allocable to the removal, processing or sale of such natural gas liquids or liquefiable hydrocarbons.

5.3 At any time that the Optionee exercises its option, then in consideration for the sale by Shipper of the extracted natural gas liquids or liquefiable hydrocarbons, Transporter solely in its capacity as agent for the Optionee, shall arrange for the delivery to Shipper by the U.S. Transporter at delivery points on the U.S. Pipeline of quantities of Natural Gas that have a heating value equal to the heating value of the quantities of such extracted natural gas liquids or liquefiable hydrocarbons acquired by the Optionee.

5.4 Shipper will, at the time of execution and delivery of this Transportation Service Agreement, or at any time thereafter as required by Transporter, execute, and, if required by Transporter, cause any of its Affiliates or any other Person who has been allocated transportation service on the U.S. Pipeline for volumes of Natural Gas corresponding to the Contracted Capacity to execute, agreements or instruments specifically providing for the option created in Section 5.2 or the acknowledgement of such option in the forms required by Transporter, provided that such agreements or instruments will not:

(a) affect, vary or alter the amounts payable by Shipper for transportation service under this Transportation Service Agreement; or

(b) affect, vary or alter the entitlement of Shipper to have deliveries made to it by Transporter at the Delivery Point balanced with its deliveries to Transporter on volume and heating value bases, after allowance for the Fuel Requirement; or

(c) affect, vary or alter the entitlement of Shipper or its Affiliates or any other Person who has been allocated transportation service on the U.S. Pipeline to have deliveries made to it by the U.S. Transporter at delivery points on the U.S. Pipeline balanced with its deliveries to the U.S. Transporter on a heating value basis, after allowance for the U.S. Fuel Requirement.

ARTICLE 6
TERM OF CONTRACT

6.1 This Transportation Service Agreement shall be effective from the date hereof (the "**Effective Date**") and shall continue until ___________(the "**Primary Term**"), or the final day of any extension effected pursuant to Section 6.2.

6.2 Shipper shall have the right to extend the term of this Transportation Service Agreement beyond the Primary Term for further periods of a minimum of one (1) year each by providing written notice to that effect not less than five (5) years prior to the expiration of the Primary Term or any extended terms, as the case may be. There is no limitation on the number of times Shipper may exercise this right, which will remain in effect for as long as the Canadian Pipeline remains in service.

6.3 Transporter may in its sole discretion from time to time and on a basis that is non-discriminatory to any shipper waive the requirement for five (5) years' notice contained in Section 6.2 and substitute any shorter notice period.

ARTICLE 7
NOTICES

7.1 All notices and other communications to be given or sent pursuant to the terms of the principal text of this Transportation Service Agreement shall be effected in accordance with and be subject to the provisions of the General Terms and Conditions. Shipper's address for the purposes of the General Terms and Conditions is:

Telecopier:
Attention:

ARTICLE 8
DEFAULT AND TERMINATION

8.1 Transporter Default: The occurrence and continuation of any of the following events, unless any such event occurs as a result of a breach by Shipper of its obligations under this Transportation Service Agreement, shall constitute a **"Transporter Default"**: (a) a breach by Transporter of any of its material obligations under this Transportation Service Agreement; or (b) Transporter repudiates this Transportation Service Agreement or evidences in any manner its intention not to perform its obligations under, or to be bound by, this Transportation Service Agreement.

8.2 Shipper Default: The occurrence and continuation of any of the following events, unless any such event occurs as a result of a breach by Transporter of its obligations under this Transportation Service Agreement, shall constitute a **"Shipper Default"**: (a) a breach by Shipper of any of its material obligations under this Transportation Service Agreement; or (b) Shipper repudiates this Transportation Service Agreement or evidences in any manner its intention not to perform its obligations under, or be bound by, this Transportation Service Agreement.

8.3 Remedies: Upon the occurrence and continuation of a Transporter Default under Section 8.1 or a Shipper Default under Section 8.2, the non-defaulting Party shall, at its option, have the right to specific performance of this Transportation Service Agreement, and/or to receive damages as would be available under law by giving notice to the defaulting party, and/or to terminate this Transportation Service Agreement in accordance with the provisions of Section 8.4;

8.4 Termination and Cure Period: In the event of an uncured Transporter Default or Shipper Default, then either Transporter or Shipper may thereafter terminate this Transportation Service Agreement by giving one hundred and twenty (120) days prior written notice of its intent to terminate to the defaulting or non-terminating Party; but if the default is cured within such notice period, then termination will not be effective.

8.5 Express termination: If this Transportation Service Agreement is not sooner terminated in any of the circumstances referred to in or Section 8.4, then this Transportation Service Agreement will terminate as provided for in Article 6 hereof.

8.6 Accrued rights unaffected: No termination of this Transportation Service Agreement, however effected, shall affect or extinguish any rights or obligations of the Parties which accrued prior to the date of termination or extinguish any remedies available to any Party at law, equity or as provided for herein.

ARTICLE 9
ASSIGNMENT

9.1 By Shipper: Shipper shall have the right to assign its rights and obligations, or parts thereof, under this Transportation Service Agreement subject to:

(a) compliance by the assignee with the credit requirements set out in the General Terms and Conditions;

(b) prior written approval of the Lenders, which shall not be unreasonably withheld; and

(c) prior written approval of Transporter, which shall not be unreasonably withheld.

9.2 By Transporter: Transporter, without obtaining any approvals or consents from Shipper, may assign this Transportation Service Agreement or any rights arising hereunder to any Affiliate of Transporter.

9.3 Merger, etc.: Any Person which shall succeed by purchase of all or substantially all of the assets and assumption of all or substantially all of the liabilities of, or merger or consolidation with either Transporter or Shipper, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this Transportation Service Agreement.

9.4 Pledging: It is agreed that the restrictions on assignment contained in this Article shall not in any way prevent Transporter from pledging or mortgaging to the Lenders its rights hereunder or its rights in respect of any letter of credit or other security given to Transporter by Shipper. Shipper will execute all consents to assignment and acknowledgments in favour of the Lenders as requested by the Lenders or Transporter, of any security interests created hereunder.

9.5 Partial assignment: If Shipper partially assigns its rights under this Transportation Service Agreement to an Affiliate, its rights hereunder must be exercised collectively by Shipper and its Affiliate. Any non-Affiliate partial assignee of this Transportation Service Agreement may exercise any elections or termination rights under this Transportation Service Agreement in respect of its share of the Contracted Capacity independently of the assignor or any other assigns.

ARTICLE 10
AUTHORITIES

10.1 Performance of this Transportation Service Agreement shall be subject to all valid laws, orders, decisions, rules and regulations of duly constituted governmental authorities having jurisdiction or control of any matter related hereto, including Authorities. Should either of the Parties, by force of any such law, order, decision, rule or regulation, at any time during the term of this Transportation Service Agreement be ordered or required to do any act inconsistent with the provisions hereof, then for the period during which the requirements of such law, order, decision, rule or regulation are applicable, this Transportation Service Agreement shall be deemed modified to conform with the requirement of such law, order, decision, rule or regulation; provided, however, nothing in this Section 10.1 shall alter, modify or otherwise affect the respective rights of the Parties to cancel or terminate this Transportation Service Agreement under the terms and conditions hereof.

ARTICLE 11
MISCELLANEOUS PROVISIONS

11.1 Financial Information: Shipper shall furnish to Transporter, as soon as available, and, in any event, within one hundred and twenty (120) days after the end of each fiscal year of Shipper, its audited consolidated financial statements setting forth in comparative form the corresponding figures of the preceding fiscal year together with an auditors report thereon. In addition, Shipper shall furnish to Transporter, as soon as available, and, in any event, within sixty (60) days after the end of the first three fiscal quarters of each fiscal year of Shipper, its unaudited consolidated financial statements prepared on a basis consistent with the corresponding period of the preceding fiscal year. Shipper shall furnish to Transporter any additional information regarding the business affairs, operations, assets and financial condition of Shipper as Transporter may reasonably request from time to time.

11.2 Other Documents Incorporated: The Toll Schedule Firm Transportation Service and the General Terms and Conditions set out in the Tariff are all by reference made a part of this Transportation Service Agreement and transportation service hereunder shall be subject to the provisions thereof. Transporter shall notify Shipper at any time that Transporter files with the NEB proposed revisions to the Tariff and shall provide Shipper with a copy of such revisions.

11.3 Headings for Reference: The headings used throughout this Transportation Service Agreement, the Toll Schedule Firm Transportation Service and the General Terms and Conditions are inserted for convenience of reference only and are not to be considered or taken into account in construing the terms or provisions thereof nor to be deemed in any way to qualify, modify or explain the effect of any such provisions or terms.

11.4 Supersedes Other Agreements: This Transportation Service Agreement and the schedules attached hereto reflect the whole and entire agreement among the Parties with respect to the subject matter hereof and supersede all prior agreements and understandings between the Parties with respect to the subject matter hereof.

11.5 Waiver: A new waiver by any Party of any breach or non-performance of any of the obligations to be performed by the other Party shall not take effect or be binding upon the first Party unless the waiver is expressed in writing by that Party. Any waiver so given shall extend only to the particular breach or non-performance so waived and shall not limit or affect any rights with respect to any other or future breach or non-performance.

11.6 Severability: The invalidity or unenforceability, for any reason, of any part of this Transportation Service Agreement shall not prejudice or affect the validity or enforceability or the remainder.

11.7 No Waiver: The failure of any Party to insist upon the strict performance of any of the provisions of this Transportation Service Agreement or to take advantage of any of the rights hereunder shall not be construed as a waiver of any such provisions or relinquishment of any such rights, but the same will continue in full force and effect.

ARTICLE 12
CHOICE OF LAW AND ATTORNMENT

12.1 This Transportation Service Agreement and the Tariff shall be construed and applied in accordance with and be subject to the laws of the Province of Alberta, and the laws of Canada having application therein, without recourse to any laws governing conflict of laws. Neither Party shall institute any action, suit or other proceeding with respect to any matter arising under or out of this Transportation Service Agreement other than in the Alberta Court of Queen's Bench in the Judicial Centre of Calgary. In that regard, each Party hereby irrevocably attorns to the jurisdiction of such Court in the event of any such action, suit or other proceeding by the other Party.

IN WITNESS WHEREOF, the Parties have duly executed this Transportation Service Agreement in several counterparts by their duly authorized officers.

ALLIANCE PIPELINE LIMITED PARTNERSHIP by its General Partner, **ALLIANCE PIPELINE LTD.**

PER: ______________________________

PER: ______________________________

PER: ______________________________

PER: ______________________________

SCHEDULE A

TO TRANSPORTATION SERVICE AGREEMENT dated ?

Between

ALLIANCE PIPELINE LIMITED PARTNERSHIP

and

?

DELIVERY POINT AND RECEIPT POINTS

A. Delivery Point:

The Delivery Point is the point of interconnection between the Canadian Pipeline and the U.S. Pipeline.

B. Receipt Points:

The Receipt Points available for use by Shipper, subject to the terms of the Tariff, are those described in the Tariff, as such description may be changed from time to time.

C. Contracted Capacity:

Shipper's Contracted Capacity pursuant to this Transportation Service Agreement is ? $10^3m^3/d$.

The sum of the Primary Receipt Point Capacities designated by Shipper for TAC Receipt Points for purposes of billing the Demand Charge Surcharge is ? $10^3m^3/d$.

D. Primary Receipt Points Designated by Shipper and Approved by Transporter:

The Primary Receipt Points and associated Primary Receipt Point Capacities designated by Shipper and approved by Transporter are as follows:

Alliance Identification		**Designated Primary Receipt Point Capacity $10^3m^3/d$**		
Primary Receipt Point Name	**Receipt Point Number**	**Designated Primary Receipt Point Capacity**	**TAC Receipt Point (Y/N)**	**Taylor-Aitken Creek**
Total Designated Primary Receipt Point Capacity: *(Not to Exceed 125% of Contracted Capacity)*				
Total Current TAC Designated Primary Receipt Point Capacity:				

Revision 0 [Date of TSA]

SCHEDULE B
TO TRANSPORTATION SERVICE AGREEMENT
dated this--------- day of -------------------------, 2000

between

ALLIANCE PIPELINE LIMITED PARTNERSHIP

and

TOLL PRINCIPLES

1. Subject to the incentive provisions in item 4 below, the Demand Charge will be calculated on a per unit of capacity basis to provide for the recovery by the Transporter of all of the fixed costs of providing service. In addition, Shippers will pay a Commodity Charge for volumes actually shipped, plus fuel.

2. A deemed capital structure of 70% debt and 30% equity for the Primary Term.

3. A cost of debt calculated using a rate of interest equal to the weighted average of the interest rates borne by Transporter's debt. Changes in Transporter's actual weighted average cost of debt will be reflected in the Canadian Pipeline's tolls from time to time as approved by the NEB.

4. Return on Equity.

   - Base rate of return on equity of 12%.

   - Base rate of return on equity is subject to an incentive adjustment. The resulting rate of return will apply for the Primary Term.

   - The base rate of return on equity will be increased or decreased inversely with increases or decreases in the actual capital cost versus the estimated capital cost [stated in paragraph 11 of this Schedule B] of the Canadian Pipeline. The adjustment formula will be linear so that any variations between actual and estimated capital cost will be reflected in the adjusted rate of return on equity. For example, a 10% increase in the actual capital cost, versus the estimated capital cost, would result in a decrease of 0.5% (50 basis points) in the base rate of return on equity. Similarly, a 20% decrease in the actual capital cost versus the estimated capital cost would result in an increase in the base rate of return on equity of 1.0% (100 basis points). The incentive rate of return increase or decrease will be limited to a maximum of 2% (200 basis points).

- Base rate of return on equity is subject to a further adjustment in accordance with Section 3.6 of the Transportation Service Agreement.

5. Income taxes will be calculated on the flow through basis for the Primary Term of the Transportation Service Agreement.

6. The depreciation on transportation plant used for purposes of deriving tolls will be calculated annually in accordance with Table 1 (attached).

7. The rate base will include, among other things, actual capital costs.

8. The Demand Charges will be calculated based upon the higher of the sum of Contracted Capacities or 37,530 10^3m^3/d (1325 MMcfd) for the Primary Term and any extension of the Primary Term of the Transportation Service Agreement.

9. There will be a Commodity Charge which will recover those costs that vary with volumes actually shipped for the Primary Term and any extension of the Primary Term of the Transportation Service Agreement.

10. Fuel costs will be recovered on an actual tracked basis. Shippers will be required to supply fuel but they will not have to maintain Contracted Capacities for fuel. Fuel required for the U.S. portion of the Alliance system will be transported by Transporter.

11. The estimated capital cost of the Canadian Pipeline, excluding AFUDC, at a system design of 37,530 10^3m^3/d (1325 MMcfd) is $2.0707 billion (Canadian).

12. Changes in Transporter's operating and maintenance costs will be reflected in its tolls from time to time.

13. The toll for Authorized Overrun Service will be the Commodity Charge, plus fuel, for the Primary Term and any extension of the Primary Term of the Transportation Service Agreement.

14. The firm service toll for gas received in Alberta and Saskatchewan will be a single uniform toll.

15. A separate British Columbia zone will be established for the Aitken Creek Lateral and that part of the Shipper's Contracted Capacity allocated to Primary Receipt Points in the Aitken Creek Lateral will be subject to a demand charge which is higher than the Demand Charge for the Alberta/Saskatchewan zone. The Demand Charge Surcharge will be fixed at $42.95/$10^3m^3$/month for the Primary Term of the Transportation Service Agreement. All B.C. Shippers will pay the same per unit of capacity B.C.

zone demand charge.

TABLE 1

Year	Depreciation Rate
1	3.027%
2	3.299%
3	3.571%
4	3.842%
5	4.114%
6	2.686%
7	2.658%
8	2.930%
9	3.202%
10	3.473%
11	3.745%
12	4.017%
13	4.289%
14	4.561%
15	4.832%
16	4.575%
17	4.575%
18	4.575%
19	4.575%
20	4.575%
21	4.575%
22	4.575%
23	4.575%
24	4.575%
25	4.575%

SCHEDULE C
TO TRANSPORTATION SERVICE AGREEMENT
dated this_____ day of _____________, 2000

between

ALLIANCE PIPELINE LIMITED PARTNERSHIP

and

OPTIONEE

The Optionee is Aux Sable Liquid Products LP.

Alberta Clipper

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

June 28, 2007

Mr. Richard Bird
President
Enbridge Pipelines Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta T2P 3L8

Dear Mr. Bird:

Re: Enbridge Pipelines' Alberta Clipper Expansion Project

This letter confirms that pursuant to Paragraph 2 of the Alberta Clipper Canada Settlement dated June 28, 2007 between Enbridge Pipelines Inc. (EPI) and the Canadian Association of Petroleum Producers (the "Alberta Clipper Canada Settlement"),the Canadian Association of Petroleum Producers supports the Alberta Clipper Canada Settlement and the development of a new 36" pipeline from Hardisty to Superior, with the necessary ancillary facilities, known as the Alberta Clipper Expansion Project. This will add an initial 450,000 barrels per day capacity, is targeted to be in-service by July 1, 2010 and allows expansions up to 800,000 barrels per day. Alberta Clipper will be integrated with, and form part of, the existing Enbridge Mainline system in Canada and the EEP Lakehead system in the US. The terms for the Canadian section of the Alberta Clipper Expansion Project are more fully described in the Alberta Clipper Canada Settlement.

Sincerely,

Greg Stringham
Vice President, Markets and Fiscal Policy

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

403, 235 Water Street
St. John's, Newfoundland
Canada A1C 1B6
Tel (709) 724-4200
Fax (709) 724-4225

Email: communication@capp.ca Website: www.capp.ca

Dated: June 28, 2007

Alberta Clipper Canada Settlement

This settlement sets forth certain terms concerning the Canadian segment of the proposed expansion of the Mainline System in Canada and EELP System in the U.S., which expansion is referred to as "Alberta Clipper", which involves construction of a new pipeline to transport heavy crude petroleum from Hardisty, Alberta to Superior, Wisconsin.

For purposes of this settlement:

"Alberta Clipper Canada" means the Canadian segment of Alberta Clipper.

"Alberta Clipper Canada Component" means the portion of the Mainline System costs that is attributable to the CRR for Alberta Clipper Canada and, if applicable, the NCRR for Alberta Clipper Canada, in accordance with Paragraphs 4 and 5 hereof.

"Alberta Clipper U.S." means the U.S. segment of Alberta Clipper.

"Alberta Clipper U.S. Term Sheet" means the Alberta Clipper U.S. Term Sheet dated June 28, 2007 concerning Alberta Clipper U.S.

"Allowance for Funds Used During Construction" or "AFUDC" means the allowance referenced in Paragraph 4(b)(ii) hereof.

"Allowance for Working Capital" means the allowance described in Paragraph 4(b)(iii) hereof.

"Capital Costs" means all costs incurred by EPI in seeking and obtaining regulatory approval for and in the development, design, procurement, installation, construction and commissioning of Alberta Clipper Canada.

"CAPP" means the Canadian Association of Petroleum Producers.

"Controllable Costs" means the Capital Costs of constructing Alberta Clipper Canada, excluding the Non-Controllable Costs.

"Cost of Debt" means the cost of debt described in Paragraph 4(e) hereof.

"CRR" has the meaning set forth in Paragraph 3(a) hereof.

"Dollars" or "$" means Canadian dollars.

"EELP" means Enbridge Energy, Limited Partnership.

"EELP System" means the crude oil and liquid petroleum pipeline that extends from the international border near Neche, North Dakota to the international border near Marysville, Michigan with an extension across the Niagara River into the Buffalo, New York area, owned by EELP and regulated by the U.S. Federal Energy Regulatory Commission, as such pipeline may be expanded or modified from time to time.

"Enbridge" means EPI and EELP collectively.

"EPI" means Enbridge Pipelines Inc.

"GAAP" means Canadian generally accepted accounting principles.

"GDPP" means the average annual Gross Domestic Product Implicit Price Index published by Statistics Canada in March (Catalogue No. 13-001-XPB "National Income and Expenditure"), including any amendments or replacements thereto.

"In-Service Date" means the date upon which Alberta Clipper Canada is able to accept oil.

"Long Lived Assets" means assets contained in the following Oil Pipeline Uniform Accounting Regulations asset categories as utilized by EPI and approved by the NEB: 152.00 - Rights of Way; 153.02 - Pipelines; 156.02 - Steel Buildings; 156.03 - Other Buildings; 159.00 - Station Oil Lines/Tank Lines/Manifolds; 161.01 Oil Tanks.

"Mainline System" means the crude oil and liquid petroleum pipeline that extends from Edmonton Alberta to the U.S. border near Gretna, Manitoba and includes Alberta Clipper Canada as well as all of the EPI NEB regulated pipeline operations including all facilities and operations associated with the Terrace Expansion (but not including Line 8 or Line 9), as such system may be expanded or modified from time to time.

"NEB" means the Canadian National Energy Board.

"Non-Controllable Costs" means the Capital Costs for which estimates are set forth in Part 1 of Schedule B attached to this settlement.

"NCRR" has the meaning set forth in Paragraph 3(b) hereof.

"Parties" means CAPP and EPI collectively; "Party" means either CAPP or EPI.

"ROE" has the meaning set forth in Paragraph 4(d) hereof.

"2005 Incentive Tolling Settlement" means the negotiated toll settlement dated December 19, 2005 between EPI and CAPP and approved by the NEB for the years 2005-2009.

"2010 Incentive Tolling Settlement" means a negotiated toll settlement to be negotiated after the date hereof between EPI and CAPP on the key terms of an incentive tolling settlement and that would be the successor to the 2005 Incentive Tolling Settlement.

Certain other terms are defined elsewhere in this settlement. In addition, the word “including” means “including without limitation,” and the word “hereof” refers to this settlement as a whole.

1. Project Scope

The project scope of Alberta Clipper Canada is described in Schedule A attached to this settlement. The project will include all necessary infrastructure to manage the transportation of 450,000 barrels per day of heavy capacity on Alberta Clipper Canada under ordinary operating conditions and all terminal and related facilities (not including receipt tankage) to facilitate such transportation.

2. Term

(a) The term of this settlement (the “Term”) will commence on the date of a duly authorized letter of support from CAPP fully endorsing this settlement and will continue until the fifteenth anniversary of the In-Service Date of Alberta Clipper Canada.

(b) 24 months prior to the expiration of the Term, the Parties will begin negotiating a new agreement that will become effective upon expiry of this settlement. If the Parties do not reach a new agreement at least 6 months prior to expiry of this settlement, the terms of the new agreement shall be subject to the dispute resolution provisions set forth in Paragraph 15 hereof.

3. Revenue Requirement

Alberta Clipper Canada’s revenue requirement shall consist of:

(a) a capital revenue requirement (“CRR”), including a return on rate base as more particularly set out in Paragraph 4; and

(b) a non-capital revenue requirement (“NCRR”) as set out in Paragraph 5 below.

4. Capital Revenue Requirement

The CRR will be recovered on a rolled-in basis in the Mainline System costs and will be calculated by EPI based on the principles set forth in this Paragraph 4.

(a) Capital Structure

The capital structure will be a deemed capital structure consisting of 55 % debt and 45 % equity.

(b) Rate Base

The rate base of Alberta Clipper Canada will (except as provided in Paragraphs 7 and 9 below) comprise all Capital Costs, the Allowance for Funds Used During Construction, and the Allowance for Working Capital, less accumulated depreciation, subject to the provisions of Paragraph 10 below.

The capital structure specified in Paragraph 4(a) will be applied to the rate base for calculation of the ROE and Cost of Debt.

(i) Capital Costs

Except as provided in Paragraph 7 below, all reasonable Capital Costs will be capitalized and included in the rate base.

(ii) Allowance for Funds Used During Construction (“AFUDC”)

Subject to Paragraph 7 below, AFUDC will be calculated on a monthly basis by multiplying the cost of the construction work in progress, including any existing AFUDC balance, by a rate equal to EPI’s weighted average cost of capital using the capital structure specified in Paragraph 4(a), 1/12th of the annual ROE specified in Paragraph 4(d), and 1/12th of EPI’s annual weighted average cost of debt, including short term debt, borrowed under EPI's commercial paper program or drawn under EPI's bank credit facilities, specifically attributed to Albert Clipper Canada cost of construction work in progress.

An example of the calculation of AFUDC using illustrative numbers is set forth in Schedule C attached hereto.

(iii) Allowance for Working Capital

An amount equal to one twelfth (1/12) of the sum of: (1) the annual operating, maintenance and administrative expenses described in Paragraph 5(a) hereof, plus (2) the annual power costs described in Paragraph 5(b) hereof will be included in the rate base as an allowance for working capital. This amount will be escalated annually on each anniversary of the In-Service Date by 75% of GDPP.

(c) **Depreciation**

All items included in the rate base, except for the Allowance for Working Capital, will be subject to depreciation. Depreciation for items associated with Alberta Clipper Canada that are not Long Lived Assets will be in accordance with NEB's approved depreciation rates. Depreciation for Long Lived Assets associated with Alberta Clipper Canada will be based on an initial expected economic life of 30 years (3 1/3 % per annum). In the event that, during the Term, any periodic depreciation studies of Long Lived Assets are, subject to any approval or comment rights of CAPP under the 2010 Incentive Tolling Settlement, submitted by EPI to the NEB, which (a) extend the economic planning horizon beyond 2040, and (b) are accepted by the NEB, then the depreciation of Long Lived Assets will be based on that new expected economic life. In the event that, during the Term, any periodic depreciation studies of items that are not Long Lived Assets are, subject to any approval or comment rights of CAPP under the 2010 Incentive Tolling Settlement, submitted by EPI to the NEB, which are accepted by the NEB, then the depreciation of such assets will be based on the expected economic life approved by the NEB.

(d) **Return on Equity**

The annual return on equity ("ROE") for Alberta Clipper Canada will be equal to the NEB multi-pipeline rate plus a 225 basis point adjustment. If the NEB ceases to publish a multi-pipeline rate during the Term, the Parties will meet to agree on a new benchmark to which will be applied the 225 basis point adjustment (or such other basis point adjustment as shall result in an ROE that is reasonably equivalent to the NEB multi-pipeline rate plus 225 basis points). If such agreement is not forthcoming within 90 days, then the amount of the ROE shall be subject to the dispute resolution provisions set forth in Paragraph 15 hereof.

(e) **Cost of Debt**

The Cost of Debt will be the weighted average cost of long-term debt incurred by EPI arising from debt securities issuances for Alberta Clipper Canada. EPI will, acting reasonably, seek to issue the Alberta Clipper Canada long-term debt at points of time either shortly before or shortly after the In-Service Date of Alberta Clipper Canada in order to take advantage of suitable market conditions. EPI will issue debt in notional sizes and maturities that seek to minimize refinancing risks while managing total interest cost. EPI debt securities issuances will be specifically attributed to Alberta Clipper Canada, in whole or in part, to match the aggregate debt component of the Alberta Clipper Canada rate base. EPI will identify such debt as attributable to Alberta Clipper Canada, and will notify CAPP within fifteen business days after the receipt of proceeds of such debt.

To the extent any Alberta Clipper Canada long-term debt matures during the Term, the interest cost of the then-issued refinancing debt will be incorporated into the Cost of Debt. EPI will actively manage the issuance of the appropriate amount of debt associated with Alberta Clipper Canada in a commercially reasonable manner throughout the Term.

The Cost of Debt shall not be determined on a project financing basis.

(f) **Income Tax Allowance**

An income tax allowance based on the applicable earnings amount, statutory income tax rates, the flow-through methodology for accounting for income taxes and the applicable permanent and timing differences, appropriately adjusted to a before tax amount, on an actual or forecast basis, as applicable, all in a manner consistent with that previously approved by the NEB as amended from time to time.

(g) **Accounting Changes**

In the event of any change in GAAP or the application thereof to EPI that affects the accounting for Alberta Clipper Canada, including the accounting for income taxes on a flow-through basis, modifications to appropriately incorporate the impact, as agreed by the Parties, of any such change will be made to the determination of the CRR.

5. Non-Capital Revenue Requirement

The NCRR for Alberta Clipper Canada shall include the expenses set out in Paragraphs 5 (a) through (c) below (collectively, "Operating Expenses") as well as those capital costs set out in Paragraphs 5 (d) and (e). All of these cost components will be included in the 2010 Incentive Tolling Settlement in the manner described below. If no 2010 Tolling Settlement is agreed to prior to the In-Service Date of Alberta Clipper Canada or if the Parties cannot otherwise agree on the amounts of any of the components to be included, EPI will, in good faith, estimate (or, in the case of Section 5(a), will use its existing methodology to calculate) the amount of any or all of the components of the NCRR (the "NCRR Estimate") to be rolled into the Mainline System costs. If CAPP disputes any of the components of the NCRR Estimate, such dispute shall be subject to the dispute resolution provisions set forth in Paragraph 15 hereof.

(a) **General Operating, Maintenance and Administrative Expenses**

Annual operating, maintenance and administrative expenses for Alberta Clipper Canada, including property taxes and pipeline integrity operating expenses.

General and administrative expenses will be included according to the methodology set forth in the 2010 Incentive Tolling Settlement or, if no 2010 Incentive Tolling Settlement is agreed, will be included according to the methodology used by EPI as of the date of this settlement, as amended from time to time by EPI.

(b) **Power Costs**

(i) Power consumed by Alberta Clipper Canada will be charged on a flow-through basis, and will be subject to any power sharing mechanism incorporated as part of the 2010 Incentive Tolling Settlement.

(ii) In order to establish the base for any power cost sharing mechanism incorporated as part of the 2010 Incentive Tolling Settlement, EPI's initial estimate of the power consumption for the first 12 months of operation of Alberta Clipper Canada is attached as Schedule D to this settlement. This estimated base will be adjusted after the first 12 months to reflect the actual power costs for the first 12 months of operation of Alberta Clipper Canada.

(c) **Other (Operating Expense) Recoverables**

Operating Expenses resulting from legislation, regulations, orders, directions or non-mandatory guidelines by any government authority which result in changes to health, safety, environmental, security, anti-terrorism and taxation (other than property tax and income tax) requirements, practices or procedures for EPI will be included in the NCRR; provided that the inclusion in the NCRR of Operating Expenses resulting from compliance with non-mandatory guidelines shall be subject to agreement with CAPP.

(d) **Pipeline Integrity Capital Costs**

Pipeline integrity related capital costs for Alberta Clipper Canada will be included in the 2010 Incentive Tolling Settlement and recovered in accordance with the terms thereof.

(e) **Maintenance Capital Costs**

Maintenance related capital costs for Alberta Clipper Canada will be included in the 2010 Incentive Tolling Settlement and recovered in accordance with the terms thereof.

An illustrative, non-binding schedule of Operating Expenses for the first year of service of Alberta Clipper Canada is attached as Schedule E to this settlement.

6. Revenue Requirement Adjustment

As contemplated in Paragraph 4, the CRR will be recovered on a rolled-in basis in the Mainline System costs. As contemplated in Paragraph 5, the amount of any NCRR Estimate will be recovered on a rolled-in basis in the Mainline System costs pending resolution of any disputes related thereto. EPI will, prior to the In-Service Date, include the Alberta Clipper Canada Component in its filings based on the first year's projected costs and Mainline System throughput volumes. Thereafter, on April 1 of each succeeding year, EPI will adjust the Alberta Clipper Canada Component to reflect (i) any over-collections or under-collections resulting from actual Mainline System throughput volumes in the immediately preceding year being more or less than projected throughput volumes for such year, (ii) any over-collections or under-collections resulting from actual costs in the immediately preceding year being less or more than projected costs for such year, and (iii) projected costs and Mainline System throughput volumes for the then-current year. Such true-ups will reflect carrying charges at the rate provided for in the 2010 Incentive Tolling Settlement. If no 2010 Tolling Settlement is agreed, the carrying charges will be at a rate equal to the average of the 12 monthly bank rates for the prior year published as Series V122530 by the Bank of Canada on its website, or any successor thereto.

EPI will perform a final true-up of actual to projected costs and throughput volumes within three months after the expiration of the Term. If the final true-up discloses a difference between the projected costs and throughput volumes and the actual data, such difference (negative or positive) shall be recovered or credited on throughput volumes over the following twelve month-period. The mechanism set forth in this Paragraph 6 for the adjustment of the Alberta Clipper Canada Component will be included in the 2010 Incentive Tolling Settlement.

Illustrations of the annual adjustment of the Alberta Clipper Canada Component are set forth in Schedule F attached to this settlement.

7. Capital Cost Risk Sharing

(a) Schedule B attached to this settlement sets forth the results of a probabilistic analysis of the Controllable Costs and Non-Controllable Costs, based on the May, 2007 estimate, to determine the P10, P55, and P90 amounts to be utilized in this Paragraph 7.

(b) The full amount of actual Non-Controllable Costs for Alberta Clipper Canada (including AFUDC thereon), will be included in the Alberta Clipper Canada rate base.

The Capital Costs included in the Alberta Clipper Canada rate base for actual Controllable Costs will be calculated as provided below.

(i) If actual Controllable Costs for Alberta Clipper Canada (such costs, "ACC") incurred in construction are equal to or greater than the P90 amount set forth in Part 2 of Schedule B, the amount to be included for Controllable Costs shall equal:

- P55 + (0.75 x (P90 – P55)) + (0.50 x (ACC – P90))

(ii) If ACC incurred in construction are less than the P90 amount but greater than the P55 amount set forth in Part 2 of Schedule B, the amount to be included for Controllable Costs shall equal:

- P55 + 0.75 x (ACC – P55)

(iii) If ACC incurred in construction are less than the P55 amount but greater than the P10 amount set forth in Part 2 of Schedule B, the amount to be included for Controllable Costs shall equal:

- ACC + 0.25 x (P55 – ACC)

(iv) If ACC incurred in construction are equal to or less than the P10 amount set forth in Part 2 of Schedule B, the amount to be included for Controllable Costs shall equal:

- ACC + (0.25 x (P55 – P10)) + (0.50 x (P10 – ACC))

No AFUDC will be included in the Alberta Clipper Canada rate base on the amount of ACC that is excluded from such rate base through the application of the foregoing risk sharing mechanisms.

Illustrations of the foregoing risk sharing mechanism are set forth in Schedule G attached to this settlement.

8. Rules and Regulations

Alberta Clipper Canada will be subject to the Rules and Regulations Tariffs of EPI for the Mainline System, as amended from time to time.

9. In-Service Date

(a) The targeted In-Service Date of Alberta Clipper Canada is July 1, 2010 (the "Targeted Date"). EPI will use commercially reasonable efforts to achieve the Targeted Date. As of the date of this settlement, subject to timely receipt of all necessary governmental authorizations, orders, certificates, licenses, permits and approvals, EPI proposes to commence construction of Alberta Clipper Canada in August, 2008. If commencement of construction of Alberta Clipper Canada is delayed beyond August, 2008 (or any replacement date selected by EPI for the commencement of construction), or if the actual In-Service Date is delayed to a date that is later than the Targeted Date set forth above, in either case, as a result of any Unavoidable Event or Regulatory Delay, then, the Targeted Date shall be deferred by one day for each day of such delay.

For the purposes of this settlement:

"Unavoidable Event" shall mean: (1) compliance with acts, orders, regulations, or requests of any governmental authority or any person purporting to act therefore; (2) insurrections, wars, rebellion, riots, strikes, or labor disruptions; (3) action of the elements not reasonably preventable or accidental disruption; (4) breakdown of production or transportation facilities that is not reasonably preventable; (5) any event that is an "Unavoidable Event" as defined in the Alberta Clipper U.S. Term Sheet; and (6) any other cause, whether or not of the same class or kind, reasonably beyond EPI's control.

"Regulatory Delay" shall mean any problems or delays in obtaining governmental or regulatory authorizations, orders, certificates, licenses, permits and approvals required or desirable in connection with the construction of Alberta Clipper.

(b) For any day after the Targeted Date that Alberta Clipper Canada is not available to accept oil, an amount equal to (i) $14 million, multiplied by (ii) 12, divided by (iii) 365 will be deducted from the Capital Costs included in Alberta Clipper Canada's rate base.

10. Initial Capacity Verification Process

(a) The capacity provided by Alberta Clipper may be tested to confirm the actual operating capacity after the project is completed. Any such test will be performed by EPI at the time or times requested in writing by CAPP, except that no such test shall be performed at any time when either Alberta Clipper Canada or Alberta Clipper U.S. is subject to an Unavoidable Event. Subject to the immediately preceding sentence, EPI will be required to conduct the test within 2 months of receiving the notice from CAPP unless another date is mutually agreed upon.

(b) The capacity test parameters will be consistent with the Terrace agreement (a 72 hour test targeting operating capacity, and EPI has the option to retest).

(c) Subject to Unavoidable Event exceptions, over the 72 hour period the line must achieve 105.5% of annual capacity of 450,000 barrels per day, adjusted for seasonal temperatures, consistent with the test parameters set forth in the Terrace agreement (the "Target Capacity").

(d) If the Target Capacity cannot be achieved for the test period (other than by reason of an Unavoidable Event), then, until capacity of Alberta Clipper is restored to at least the Target Capacity, Alberta Clipper Canada's rate base will be reduced by a fraction, the numerator of which is the amount by which capacity is less than the Target Capacity and the denominator of which is the Target Capacity.

11. Audit and Review

(a) Audit/Review of Cost Allocation

Upon reasonable written notice to EPI by CAPP, but subject to EPI's confidentiality obligations to third parties, CAPP may elect to conduct the following review and audit, upon and subject to the terms set forth in this Paragraph 11:

(i) Prior to issuance of NEB's approval of Alberta Clipper Canada, a review of (y) EPI's proposed procedures to ensure that expenses of Alberta Clipper Canada will be appropriately coded and (z) EPI's proposed allocation of Capital Costs between Controllable Costs and Non-Controllable Costs. The review will include each segment as defined in EPI's costing documents; and

(ii) On or before the second anniversary of the In-Service Date of Alberta Clipper Canada, an audit of the Capital Costs of Alberta Clipper Canada. The range of such audit shall cover such data as shall be needed to reasonably confirm whether inclusion of Capital Costs has been appropriate and whether all Capital Costs components have been fairly allocated.

(b) CAPP Auditors

For purposes of performing the review and audit functions described in Paragraph 11(a) hereof, independent parties will be selected by CAPP, subject to EPI's approval, which approval shall not be unreasonably withheld (the "Auditors"). The review and audit shall each be conducted during normal business hours. EPI will provide the Auditors with reasonable access to EPI source data necessary for the conduct of the review and audit. The Auditors will maintain confidentiality and not disclose source data reasonably identified by EPI as confidential. Source data which is subject to any form of legal privilege will not be made available.

(c) Conduct of Review/Audit

With respect to the review and audit described in Paragraph 11(a), each of the Auditors will:

(i) execute and deliver a confidentiality agreement with EPI prior to commencing the review and another confidentiality agreement prior to commencing the audit. Each such confidentiality agreement shall be in form and substance acceptable to EPI;
(ii) subject to (iii) below, have access to historical EPI source data regarding Capital Cost expenditures; and
(iii) have access to EPI auditors' working papers, where EPI is able, through its use of reasonable commercial efforts, to cause the disclosure of such working papers to CAPP.

(d) No Further Reviews or Audits

Upon completion of the review described in Paragraph 11(a)(i) and audit described in Paragraph 11(a)(ii), and upon resolution of any issues arising as a result of such review and/or audit, no further review or audit shall be conducted by CAPP pursuant to this Paragraph 11.

The CAPP review will be deemed to be complete no later than one year following the execution of the confidentiality agreement required by EPI for the review unless otherwise agreed to by CAPP and EPI. The CAPP audit will be deemed to be complete no later than one year following the execution of the confidentiality agreement required by EPI for the audit unless otherwise agreed to by CAPP and EPI.

12. Upstreaming

Any New Enbridge Pipeline that is underpinned by long term transportation contracts will not use any Mainline System facilities without the prior approval of CAPP, but will otherwise have no impact on this settlement. Adjustments to this settlement in connection with any New Enbridge Pipeline that is not underpinned by long term transportation contracts will be negotiated between EPI and CAPP prior to the construction of such project. For the purposes of this Paragraph 12, a "New Enbridge Pipeline" means a pipeline for transportation of volumes of heavy crude out of the Western Canada Sedimentary Basin in which Enbridge Inc., EELP or an entity that is owned by Enbridge Inc. or EELP has at least a 50% ownership interest and that is constructed after the date of this settlement.

13. Other (Capital Cost) Recoverables

Capital costs resulting from legislation, regulations, orders or directions or non-mandatory guidelines by any government authority which result in changes to EPI's health, safety, environmental, security, anti-terrorism and taxation (other than property tax and income tax) requirements, practices or procedures shall be recovered by EPI through a non-routine adjustment mechanism included in the 2010 Incentive Tolling Settlement. If no 2010 Incentive Tolling Settlement including such a mechanism is agreed to, such costs will instead be rolled into the Mainline System costs; provided that rolling into the Mainline System costs of any capital costs resulting from compliance with non-mandatory guidelines shall be subject to agreement with CAPP.

14. Tankage

Receipt tankage requirements for Alberta Clipper Canada will be addressed by the CAPP Tankage Committee and will be subject to subsequent agreement between CAPP and EPI.

15. Dispute Resolution

(a) In the event of a dispute arising out of or relating to this settlement (a "Dispute"), the Party wishing to initiate dispute resolution shall give written notice (the "Dispute Notice") to the other Party of the Dispute and outline in reasonable detail the relevant information concerning the Dispute. Within 14 days following receipt of the Dispute Notice, the Parties will each appoint representatives to meet to discuss and attempt to resolve the Dispute. Such representatives shall be individuals that are technically qualified to appreciate and assess the Dispute and have authority to negotiate the Dispute. If the Dispute is not settled within 90 days of receipt of the Dispute Notice, the negotiations will be deemed to have failed.

(b) If the Dispute is not resolved pursuant to the process in (a) above, the Dispute may be referred to the NEB by either Party, for binding resolution on an expedited basis.

(c) For the avoidance of doubt, it is expressly agreed that the reference in certain paragraphs of this settlement to dispute resolution pursuant to this Paragraph 15 is included so that there is a fallback if no 2010 Incentive Tolling Settlement is agreed upon by the Parties. All provisions of this settlement are, however, subject to the dispute resolution provisions of this Paragraph 15, whether or not such provisions expressly reference these provisions.

16. Condition to Implementation

Implementation of this settlement will be subject to (i) approval by the NEB of this settlement, and (ii) approval by the FERC of the Alberta Clipper U.S. Term Sheet.

17. Interpretation

The Parties have concluded the Alberta Clipper Canada settlement on a negotiated basis based on all of the components reflected herein. The Parties have agreed that no individual components(s) of this settlement is to be construed as representing the position of either Party. No element of this settlement is to be considered acceptable to either Party in isolation from all other aspects of this settlement. The Parties' intent is that this settlement is to be viewed as a whole and that there should be no prejudice to the positions of either Party in the future when the Term expires.

Schedule A

Project Scope for Alberta Clipper Canada

Project Description

New 36 inch pipeline from Hardisty, AB to Superior WI with initial annual capacity of 450,000 bpd, which capacity is incremental to the capacity of the Mainline System, and which is designed for an ultimate annual capacity of 800,000 bpd, assuming 100% heavy crude service.

Canadian Overview

- Approximately 1,074 kilometers of new 36-inch diameter pipeline from Hardisty, Alberta to the Canada-United States border near Gretna, Manitoba
- 8 new pump stations at existing station locations
- 1 new pump station located in Rowatt, south of Regina Saskatchewan
- Pump stations shall be designed such that flow of 450 kbpd can be maintained with the loss of a single pump unit.
- The Reynolds Number of Alberta Clipper Canada will be 3300.

Terminal Scope

Hardisty

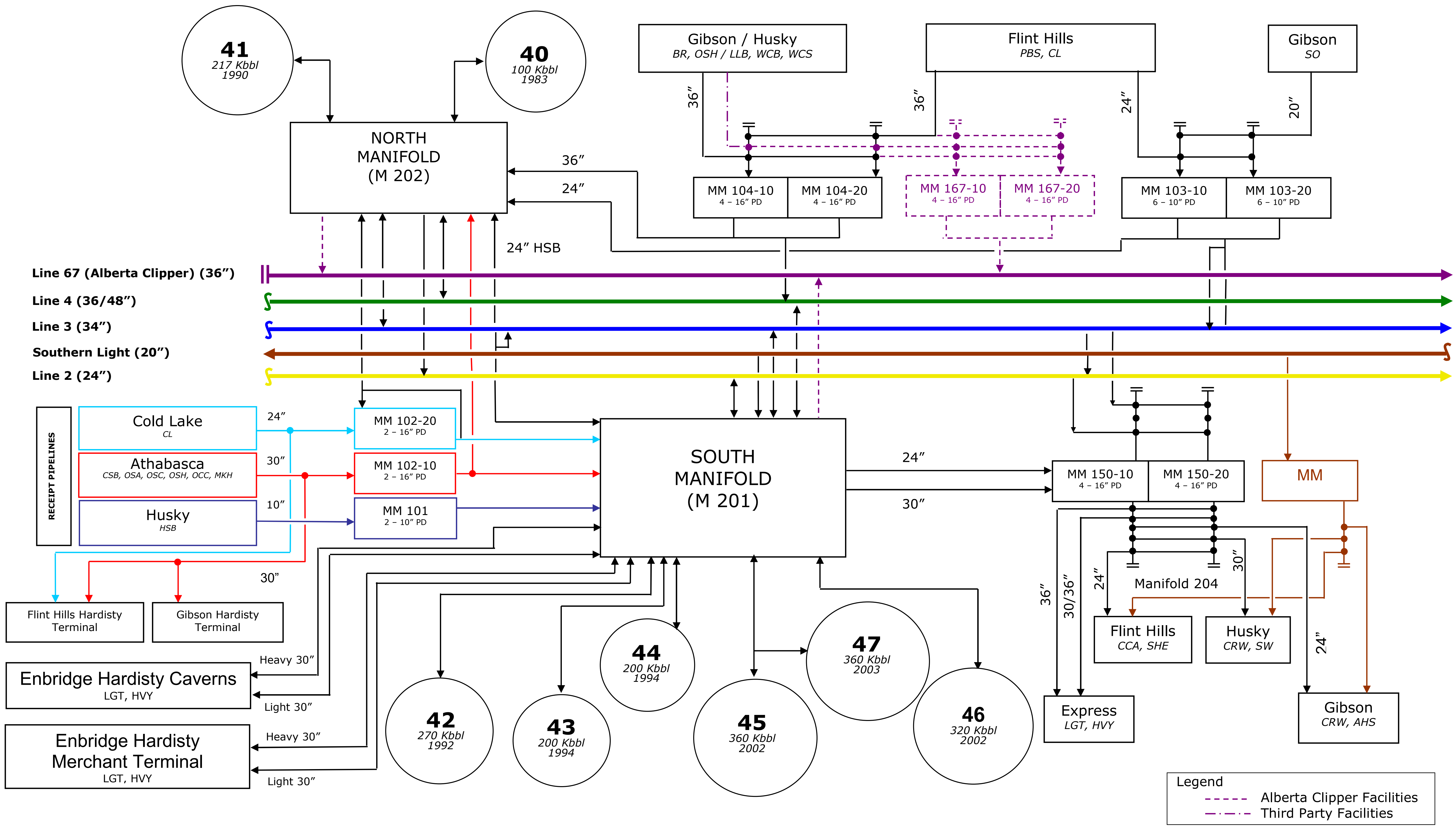
- 2 meter manifolds with 4-16-inch PD meters
- 30-inch prover
- 30-inch transfer line from Manifolds 104, 167, 201, and 202 to Alberta Clipper Canada. This will create manifold connections capable of meeting 111% of the annual capacity of Alberta Clipper Canada with connectivity to:
    - Husky terminal
    - Gibson terminal
    - Flint Hills terminal
    - Hardisty Caverns Complex
    - Enbridge Tank Terminal
- No requirement for breakout tankage

Other

- No other connections in Canada

ENBRIDGE

Hardisty Terminal
Lines 2, 3, 4, 31 & Alberta Clipper (Line 67)
Alberta Clipper In Service Q3 2010



Schedule B

Capital Costs For Alberta Clipper Canada

Part 1

Non Controllable Cost Estimate ($As Spent)		
P10	P55	P90
454.46	626.17	783.58

Part 2

Controllable Cost Estimate ($As Spent)		
P10	P55	P90
1133.64	1533.03	1905.52

Part 3

Total Cost Estimate ($As Spent)		
P10	P55	P90
1588.10	2159.20	2689.10

Note, the foregoing estimates are net of AFUDC.

Schedule C

Illustration of AFUDC

See attached spreadsheet

Albert Clipper Canada Allowance for Funds Used During Construction Illustrative Example Schedule C

Assumptions	
ROE	11.25%
COD	6.50%
Equity Thickness	45%
Debt Thickness	55%

		January	February	March	April	May	June	July	August	September	October	November	December
Construction Work in Progress (CWIP)													
Opening	Line 1 = Previous Line 3		1,000	1,900	3,100	3,900	7,400	11,900	16,400	24,600	29,100	32,300	33,300
Additions	Line 2 = Input	1,000	900	1,200	800	3,500	4,500	4,500	8,200	4,500	3,200	1,000	1,000
Closing	Line 3 = Line 1 + Line 2	1,000	1,900	3,100	3,900	7,400	11,900	16,400	24,600	29,100	32,300	33,300	34,300
Allowance for Equity Used During Construction (AEDC)													
Opening	Line 4 = Previous Line 6	-	2	8	19	34	58	99	159	247	362	494	636
Additions	Line 5 = (Line 1+ Line 2*0.5 + Line 4 + Line 7) * ROE/12 * Equity Thickness	2	6	11	15	24	41	60	88	115	132	142	147
Closing	Line 6 = Line 4 + Line 5	2	8	19	34	58	99	159	247	362	494	636	783
Allowance for Debt Used During Construction (AIDC)													
Opening	Line 7 = Previous Line 9	-	1	5	12	23	40	69	112	174	255	348	448
Additions	Line 8 = (Line 1+ Line 2*0.5 + Line 4 + Line 7) * COD/12 * Debt Thickness	1	4	7	11	17	29	43	62	81	93	100	104
Closing	Line 9 = Line 7 + Line 8	1	5	12	23	40	69	112	174	255	348	448	552
CumulativeAllowance for Funds Used During Construction (AFUDC)	Line 10 = Line 6 + Line 9	3	13	31	57	98	168	271	421	617	842	1,084	1,335

The numbers used in this calculation are for illustrative purposes only
All dollar figures are in $CDN '000's

6/28/2007

Schedule D

Estimated Power Quantity For Alberta Clipper Canada

Alberta Clipper operating at 450 kbpd with heavy line fill

Estimated Power Consumption, GigaWatt-hrs per year: 559.5 Gw-hr

Schedule E

Illustrative First Year's Operating Costs

Assumptions:

All costs are expressed in as spent, Canadian dollars
First full year of operation is 2010
Inflation assumed to be 2.5%

	Year 1 ($ MM)
Operating Expenses **settlement reference: Paragraph 5(a)**	12.58
Property Tax **settlement reference: Paragraph 5(a)**	7.06
Integrity Operating Costs **settlement reference: Paragraph 5(a)**	0.6
Integrity Capital Costs **settlement reference: Paragraph 5(d)**	0.35
Maintenance Capital Costs **settlement reference: Paragraph 5(e)**	0.10

Note, this Schedule is illustrative only and actual Operating Expenses may be less or more than as set forth in this Schedule E

Schedule F

Illustration of Alberta Clipper Canada Component Adjustment

See attached spreadsheet

Schedule F
Illustration of Component Adjustment: Over Collection

Assumptions:
The Overall Return on Rate Base changed due to the over-forecasting of Cost of Debt
The Income Tax Allowance changed due to the under-forecasting of the tax rate
All dollar figures are in $CDN '000's
Carrying Charge 5%

	Year 2 Over Collection					
	Year 2 Over Collection					
	Term Sheet Reference	Forecast RR	Actuals	Difference	Recognized in RR	Final RR
Volumes (bpd)		2,500,000	3,000,000			3,000,000
Overall Return on Rate Base	4(a) 4(b) 4(d) 4(e)	$205,000	$200,000	($5,000)	100%	$200,000
Income Tax Allowance	4(f)	$23,000	$24,000	$1,000	100%	$24,000
Operating Expenses						
Operating Expenses	5(a)	Will be included as part of the 2010 ITS				
Property Taxes		Will be included as part of the 2010 ITS				
Power Costs	5(b)	Will be included as part of the 2010 ITS				
Integrity	5(d) 5(e)	Will be included as part of the 2010 ITS				
Other Recoverables	5(c)	Will be included as part of the 2010 ITS				
Depreciation Expense	4(c)	$85,000	$85,000	$0	100%	$85,000
Total Revenue Requirement		**$313,000**				**$309,000**
True Up from Previous Year	6	$0				$0
Net Revenue Requirement		**$313,000**				**$309,000**
Actual Revenue Collected						$325,000
Difference	6					($16,000)
Carrying Charge						($800)
True Up Carried to Following Year						($16,800)

Conclusion:
Actual Revenue collected in Year 2 was 325,000 while the net revenue requirement in Year 2 was 309,000
In Year 3, the net revenue requirement will be reduced by a total of 16,800; 16,000 in accordance with the over collection in Year 2, and 800 in accordance with the 5% carrying charge

Illustration of Component Adjustment: Under Collection

Assumptions:
The Overall Return on Rate Base changed due to the over-forecasting of Cost of Debt
The Income Tax Allowance changed due to the under-forecasting of the tax rate
All dollar figures are in $CDN '000's
Carrying Charge 5%

	Year 2 Under Collection					
	Year 2					
		Forecast RR	Actuals	Difference	Recognized in RR	Final RR
Volumes		3,000,000	2,500,000			2,500,000
Overall Return on Rate Base	4(a) 4(b) 4(d) 4(e)	$200,000	$205,000	$5,000	100%	$205,000
Income Tax Allowance	4(f)	$24,000	$23,000	($1,000)	100%	$23,000
Operating Expenses						
Operating Expenses	5(a)	Will be included as part of the 2010 ITS				
Property Taxes		Will be included as part of the 2010 ITS				
Power Costs	5(b)	Will be included as part of the 2010 ITS				
Integrity	5(d) 5(e)	Will be included as part of the 2010 ITS				
Other Recoverables	5(c)	Will be included as part of the 2010 ITS				
Depreciation Expense	4(c)	$85,000	$85,000	$0	100%	$85,000
Total Revenue Requirement		**$309,000**				**$313,000**
True Up from Previous Year	6	$0				$0
Net Revenue Requirement		**$309,000**				**$313,000**
Actual Revenue Collected						$300,000
Difference	6					$13,000
Carrying Charge						$650
True Up Carried to Following Year						$13,650

Conclusion:
Actual Revenue collected in Year 2 was 300,000 while the net revenue requirement in Year 2 was 313,000
In Year 3, the net revenue requirement will be increased by a total of 13,650; 13,000 in accordance with the under collection in Year 2, and 650 in accordance with the 5% carrying charge

Schedule G

Alberta Clipper Canada - Application of Capital Cost Risk Sharing

Scenario 1 - Actual Costs 20% higher than estimate in all categories

1. Cost Estimate ($MM As spent, w/o AFUDC)

	P10	P55	P90
Controllable	1133.64	1533.03	1905.52

2. Actual Costs ($MM, As spent, w/o AFUDC)

Total (w/o AFUDC)	2591.04
Non Controllable	750.99
Controllable	1840.05
AFUDC	295.00
Total (w AFUDC)	2886.04

3. Application of Risk Sharing Mechanism to Controllable Costs

Non controllable costs not subject to risk sharing ($MM w/o AFUDC) 750.99

Controllable costs subject to risk sharing ($MM w/o AFUDC) 1840.05

Formula applied to controllable costs (controllable costs > P55 and < P90)

P55 + 0.75 (Actual - P55) = Controllable Costs included in rate base

1533.03 + 0.75 (1840.05 - 1533.03) = 1763.30

Percent of controllable costs included in ratebase: 95.83%

4. Allocation of Actual AFUDC ($MM)

AFUDC allocated to Controllable costs (subject to risk sharing): 209.50
AFUDC allocated to Non controllable costs 85.50
Total Actual AFUDC 295.00

Amount of AFUDC subject to risk sharing included in rate base
Percent included in rate base 95.83%
$ amount ($MM) included in rate base 200.76

5. Total Capital Costs Included In Rate Base ($MM)

Controllable Capital Cost	1763.30
Controllable Cost AFUDC	200.76
Non Controllable Capital Cost	750.99
Non Controllable AFUDC	85.50
TOTAL	2800.55

6/28/2007

Alberta Clipper Canada - Application of Capital Cost Risk Sharing

Scenario 2 - Actual Costs 20% lower than estimate in all categories

1. Cost Estimate ($MM, As spent, w/o AFUDC)

	P10	P55	P90
Controllable	1133.64	1533.03	1905.52

2. Actual Costs ($MM, As spent, w/o AFUDC)

Total (w/o AFUDC)	1799.33
Non Controllable	522.32
Controllable	1277.01
AFUDC	214.55
Total (w AFUDC)	2013.88

3. Application of Risk Sharing Mechanism to Controllable Costs

Non controllable costs not subject to risk sharing ($MM w/o AFUDC) 522.32

Controllable costs subject to risk sharing ($MM w/o AFUDC) 1277.01

Risk Sharing formula applied to controllable costs (controllable costs > P10 and < P55)

Actual + 0.25 X (P55 - Actual) = Controllable Costs included in rate base

1277.01 + 0.25 (1533.03 - 1277.01) = 1341.02

Percent of controllable costs included in ratebase: 105.01%

4. Allocation of Actual AFUDC ($MM)

AFUDC allocated to Controllable costs (subject to risk sharing):	152.27
AFUDC allocated to Non controllable costs	62.28
Total Actual AFUDC	214.55

AFUDC subject to risk sharing included in rate base

Percent included in rate base	105.01%
$ amount ($MM) included in rate base	159.90

5. Total Capital Costs Included In Rate Base ($MM)

Controllable Capital Cost	1341.02
Controllable Cost AFUDC	159.90
Non Controllable Capital Cost	522.32
Non Controllable AFUDC	62.28
TOTAL	2085.52

Southern Lights

Southern Lights Project - OH-3-2007
Information Request No. 1

Application dated 9 May 2007 filed by Enbridge Southern Lights GP, on behalf of Enbridge Southern Lights LP (ESL), and Enbridge Pipelines Inc. (EPI); or collectively (Applicants)

Economics and Financial

Line 13 Reversal

1.1 References:

1. Application, Volume 1 s. 4.12 Negotiated Tolls, p 4-6.
2. Application, Volume 1 s. 4.13 Approval of Tolling Principles, pp 4-6 to 4-9.
3. Application, Volume 1, Appendix 2-5 Letter of Support from Canadian Association of Petroleum Producers (CAPP), dated 15 December 2006

Preamble: Reference 2 states "the base annual rate of return of 12% can be reduced down to as low as 10% if the actual costs exceed the estimate by 40% or more or increase to as high as 14% if the actual costs are less than the estimate by 40% or more." Reference 3 does not contain any reference to CAPP's support or lack of support for the toll principles.

Request: Does the Applicant have support from CAPP for the tolling principles outlined in Reference 2? If so, please provide any applicable documentation.

Response: The referenced tolling principles were part of the commercial bargain struck between the Applicant and the Committed Shippers during the Open Season process in May to July 2006. These principles were part of the package which CAPP reviewed in response to the Applicant's request for CAPP support for the Southern Lights proposal. Rather than providing specific support for individual elements of the proposal, CAPP provided its support for the proposal as a complete package.

Southern Lights Project - OH-3-2007
Information Request No. 1

Line 13 Reversal

1.2 References: Application, Volume 1, s. 4.13 Approval of Tolling Principles, pp 4-6 to 4-9.

Preamble: The Reference states "the base annual rate of return of 12% can be reduced down to as low as 10% if the actual costs exceed the estimate by 40% or more or increase to as high as 14 % if the actual costs are less than the estimate by 40% or more."

Request: (a) Please provide the rationale for the return on equity (ROE) cited, including a description of the commercial and business risks borne by the Applicant, and a justification for differences in ROE and

risks from other Group 1 pipelines regulated by the Board.

(b) Please provide the rationale for the equity thickness cited, including justification for differences from other Group 1 pipelines regulated by the Board.

Response: (a) and (b) The equity thickness and the rate of return on equity for the Line 13 Reversal were established as a result of negotiations with potential shippers. The various risks of the project were discussed and allocated between the Committed Shippers and the Applicant. The result of the risk allocation negotiation is contained in the Transportation Services Agreement.

The proposed equity thickness and rate of return on equity have regard for the following:

- The Applicant intends to arrange for debt financing for 70% of the project cost.

- Prior to the Southern Lights project reaching the operating phase, the Applicant bears the development risk of the project. If the project is not completed prior to the end of 2010, the committed shippers can exercise their right of termination without penalty.

Southern Lights Project - OH-3-2007
Information Request No. 1

- The Applicant bears the renewal risk for the committed contracts. The initial term (15 years) of the contracts cover only 60% of the investment.

- If the Southern Lights system is not capable of performing the obligations under the TSA as a result of the carrier's force majeure, the shippers are relieved of their payment obligations and the term of the TSA will be extended for a period commensurate with the duration of the event of carrier force majeure. If the event of carrier force majeure is longer than 24 months, then the committed shippers are relieved of their TSA obligations without penalty.

- The capital cost of the Southern Lights project compared to the Base capital cost will adjust the final return on equity for the Applicant. This adjustment formula was a key element in the risk allocation discussion because it aligns the Applicant's interests with the interests of the shippers. The lower the final cost, the lower the toll and the higher the return on equity for the Applicant.

Kathleen McShane of Foster Associates, Inc. was requested to provide an expert opinion on the reasonableness of the common equity ratio and rate of return on equity proposed for the Line 13 Reversal. A copy of Ms. McShane's Opinion is attached.

Trans Mountain Pipeline

INCENTIVE TOLL SETTLEMENT
FOR THE TRANS MOUNTAIN PIPELINE SYSTEM
2006 – 2010

Between

TERASEN PIPELINES (TRANS MOUNTAIN) INC.

- and –

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Incentive Toll Settlement
for the Trans Mountain Pipeline System
2006 – 2010

BETWEEN:

TERASEN PIPELINES (TRANS MOUNTAIN) INC.

- and -

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

**Incentive Toll Settlement for the
Trans Mountain Pipeline System
2006 – 2010**

1. INTRODUCTION

1.1 Terasen Pipelines (Trans Mountain) Inc. ("**TPTM**" or "**Carrier**") is a body corporate, incorporated under the laws of Canada, having its registered office in the City of Calgary, in the Province of Alberta.

1.2 TPTM owns a pipeline system (the "**System**") for the transportation of Petroleum originating at Edmonton, Alberta and terminating at Burnaby, British Columbia, with intermediate points of receipt and delivery, that is regulated by the National Energy Board (the "**Board**" or "**NEB**").

1.3 The Canadian Association of Petroleum Producers ("**CAPP**") is a trade association having its principal office in the City of Calgary, in the Province of Alberta. CAPP represents approximately 150 producer member companies that explore, develop, and produce crude oil, oil sands, natural gas liquids, natural gas and elemental sulphur throughout Canada. CAPP producer members account for over 95% of Canadian oil and gas production.

1.4 CAPP represents producers and shippers of crude oil and petroleum products (collectively the "**Shippers**") that require access to markets served by the System.

1.5 In 1996, TPTM, CAPP and Chevron Canada Limited entered into a negotiated incentive toll settlement (the "**1996 Incentive Toll Settlement**") which provided a global settlement of revenue requirement and toll issues for the System for the (five) 5 year period commencing January 1, 1996 and ending December 31, 2000. The 1996 Incentive Toll Settlement was approved by the Board by Order TO-2-96.

1.6 In 2000, TPTM, CAPP and Chevron Canada Limited entered into a negotiated incentive toll settlement (the "**2001 Incentive Toll Settlement**") which provided a global settlement of revenue requirement and toll issues for the System for the (five) 5 year period commencing January 1, 2001 and ending December 31, 2005. The 2001 Incentive Toll Settlement was approved by the Board by Order TO-1-2001.

1.7 TPTM and CAPP (of which Chevron Canada Limited is now a member) have entered into this negotiated incentive toll settlement which, subject to the approval of the Board, will provide a global settlement of revenue requirement and toll issues for the System for the (five) 5 year period commencing January 1, 2006 and ending December 31, 2010.

2. GENERAL AGREEMENT

2.1 This 2006 ITS has been reached on a negotiated basis to provide an overall settlement for the determination of tolls on the System. This 2006 ITS is to be viewed as a whole and no component of it, taken in isolation, is to be construed as representing the position of either Party other than as part of the overall negotiated settlement. No element of this 2006 ITS will be considered as being acceptable to either Party in isolation. Neither this 2006 ITS nor any individual element will form a precedent, nor operate to the prejudice of the position of either Party in the future or in other proceedings.

2.2 The Parties intend that this 2006 ITS will, through the incentive toll mechanisms set out herein, provide TPTM with the opportunity to earn a rate of return on equity greater than that determined by the NEB under the formula established in the RH-2-94 Decision. In recognition of this opportunity, TPTM will assume certain risks, provide cost certainty in identified areas and enhance service standards to Shippers as set out in this settlement.

2.3 The Parties intend that this 2006 ITS will be applicable solely to the System and will have no application to or form a precedent for other NEB regulated pipelines.

2.4 If any matter pertaining to the Tolls or Revenue Requirement of the System arises that is not anticipated or not adequately provided for in this 2006 ITS, TPTM and CAPP agree to discuss such matter and attempt to resolve it in a fair and equitable manner. In the event that the Parties are unable to resolve such matters, the dispute resolutions of Section 23 of this 2006 ITS will apply.

2.5 TPTM with CAPP's support will seek the Board's approval of this 2006 ITS.

3. INTERPRETATION

3.1 TERM:

The term of this 2006 ITS (the "**Term**") shall be from January 1, 2006 at 7:00 a.m. (Calgary time) to January 1, 2011 at 7:00 a.m. (Calgary time).

3.2 In this 2006 ITS the following words and terms will have the following meanings:

1996 Incentive Toll Settlement:	Has the meaning given to it in Section 1.5.
2001 Incentive Toll Settlement	Has the meaning given to it in Section 1.6.
2006 ITS:	Means this negotiated incentive toll settlement.
Actual Throughput:	Means, for any month during the Term, a number equal to the total volume of Petroleum delivered out of the System, adjusted to remove volumes received at Kamloops.
Affiliate:	Means any Person (a) that controls a Person, (b) that is controlled by a Person, or (c) that is controlled by the same Person that controls a Person; it being understood and agreed that for purposes of this definition the terms "controls" and "controlled by" shall mean the power to direct or cause the direction of the management and policies of another Person whether through the ownership of shares or partnership interest, a contract, trust arrangement or any other means, either directly or indirectly, that results in control in fact and without restricting the generality of the foregoing includes, with respect to the control of or by a corporation or a partnership, the ownership of shares or partnership interest carrying not less than fifty (50%) percent of the voting rights regardless of whether such ownership occurs directly or indirectly, as contemplated above;
AFUDC:	Means an allowance for funds used during construction of an Expansion to the In-Service Date of that Expansion, expressed as a percentage and calculated as follows:

1. The rate for Expansion is the sum of:

   (a) an amount representing TPTM's cost of debt, equal to the cost of debt (expressed as a percentage) multiplied by the debt portion of deemed capital structure; and

   (b) an amount representing TPTM's return on Equity; equal to the return on equity multiplied by the equity portion of the deemed capital structure;

with the deemed capital structure, cost of debt and return on equity as set forth in the Financial Parameters, and except as otherwise adjusted for the Anchor Loop Expansion pursuant to Section 14.

2. The rate for other capital projects and capital projects associated with Non-Routine Adjustments is the sum of:

   (a) an amount representing TPTM's cost of debt, equal to the cost of debt (expressed as a percentage) multiplied by the debt portion of deemed capital structure; and

   (b) an amount equal to the prevailing NEB ROE determined pursuant to the methodology established in the RH-2-94 Decision unless otherwise negotiated and agreed to by CAPP and TPTM multiplied by the equity portion of the deemed capital structure;

with the deemed capital structure and cost of debt set forth in the Financial Parameters, and except as otherwise adjusted for the Anchor Loop Expansion pursuant to Section 14.

AL Reference Rate: Means the annual rate expressed as a percentage, that is the monthly benchmark bond yield to maturity for (ten) 10 year Government of Canada bonds, (CANSIM Series V122543), as published in the Bank of Canada Weekly Financial Statistics or any successor publication, plus 80 basis points, determined on the In Service Date of the

	Anchor Loop Expansion.
Anchor Loop Expansion:	Means the program of capital expenditures required for the construction of a pipeline loop from Hinton Alberta to Rearguard British Columbia, including associated pipeline facilities, and to increase the System's Operating Capacity to 300,000 bpd, as set for hearing by NEB Order OH-1-2006.
Apportionment:	Means the situation where, for any month during the Term, nominations for the transport of Petroleum submitted by Shippers and verified and accepted by TPTM exceed, in aggregate, the Available Capacity.
Available Capacity:	Means a number equal to the volume of Petroleum, as determined by TPTM that the System is forecast to be able to transport during any month of the Term, having regard to the hydraulic capacity of the pipeline and scheduled maintenance requirements, and is measured as the volumes injected into the pipeline at the receipt points of Edmonton and Edson.
Base Reference Rate:	Means the rate applicable to (ten) 10 year Government of Canada Bonds (Bank of Canada Daily Series V39055: Selected Government of Canada benchmark bond yields: 10 year) as of January 3, 2006, the first business day of the year, and is equal to 3.97% plus sixty (60) basis points, which for greater certainty totals 4.57%.
Board or NEB:	Has the meaning given to it in Section 1.2.
Capacity Incentive Adjustment:	Means the adjustment, if any, calculated pursuant to Section 6.2.7 and Section 10 and the method provided in Schedule 7.
Capacity Penalty Adjustment:	Means the adjustment, if any, calculated pursuant to Section 6.2.8, Section 12 and the method provided in Schedule 9.
Capacity Test:	Means a test of System capacity set out in Section 16.
CAPP:	Has the meaning given to it in Section 1.3.
Carrying Charges:	Means carrying costs calculated on balances as of December 31 of the applicable year (unless the content

dictates a different date), at the average of the daily Bank Rates for each day in the applicable year, as published in the Bank of Canada Weekly Financial Statistics (CANSIM Series V39078), or any successor publication, plus 50 basis points, in accordance with the method shown in Appendix 4.

Controllable Costs: Means those construction cost elements as defined for the Anchor Loop Expansion and the Pump Station Expansion as set out in Section 15.

Depreciation and Amortization: Means the dollar amount of costs determined pursuant to Section 4.3 and the method provided in Schedule 10.

Design Capacity: Means the ex-Edmonton/Edson capacity of the System to be determined in accordance with Appendix 1. The Design Capacity may be adjusted to account for any system shutdowns or reductions in throughput rate required to accommodate the commissioning or tie-in of any facilities forming part of any Expansion. Any such adjustments to the Design Capacity will only apply during the period of time while commissioning or tie-ins are being carried out.

Dispute: Has the meaning given to it in Section 23.2.

Employee: Means all positions which are regular full time (average work week of 37.5 hours or more), regular part-time (regular work week between 4 and 37.5 hours), temporary employees (work is scheduled on a regular basis but is for a short period of time) and students (hired to supplement regular work force and must be a post secondary student aged 18 or older).

Expansion: Means either or both of the Pump Station Expansion or the Anchor Loop Expansion, as the context requires.

Expected Value: Means, in respect of a project, the dollar amount of capital costs that corresponds to a probability factor of 55% on the curve of accumulated probability distribution prepared by TPTM for that project, and which, in respect of the Pump Station Expansion, is equal to $226.4 million, and which in respect of the Anchor Loop Expansion, is equal to $438.4 million.

Financial Parameters:	Has the meaning given to it in Section 5.2.
Flow Through Costs:	Means the dollar amount of costs determined pursuant to Section 4.2 and adjusted pursuant to Section 6.2.4 and summarized on Schedule 6 and in accordance with the method provided in subschedules 6.1 and 6.2 and the calculations shown in Appendix 2.
Force Majeure:	Has the meaning given to it in the Petroleum Tariff.
GAAP:	Means generally accepted accounting principles approved by the Canadian Institute of Chartered Accountants, as amended or replaced from time to time.
GDPP:	Means, for any year, the annual average Implicit Price Index, Gross Domestic Product at market prices for that year as reported by Statistics Canada (CANSIM Table No. 3800003, Catalogue No. 13-001-XIB).
GDPP Adjustment:	Means, in any year, the difference (expressed as a percentage) between the actual GDPP for that year and the forecast GDPP (which shall be equal to the previous year's actual GDPP) for that year used to calculate the Tolls for that year in accordance with the method shown in Schedule 5.
Heavy Oil:	Means oil that has a density greater than 904 kilograms per cubic meter at 15°C or a viscosity of greater that 100 centiStokes at TPTM's Reference Temperatures (as set forth in Schedule 23).
In Service Date:	Means, in respect of any facilities, unless otherwise provided by the NEB, the date that TPTM actually puts these facilities into service, which date shall not be later than the first day of the month following issuance of a Leave to Open Order by the NEB.
Income Tax Provision:	Means the dollar amount of costs determined pursuant to Section 4.4 and the method shown on Schedule 11.
Major Expansion:	Means a capital expenditure required for construction of any project (which may include facilities at more than one geographic location) intended to provide incremental pipeline capacity of not less than 50,000

	bpd, requested or agreed to by Shippers or ordered by the NEB, but does not include the Pump Station Expansion or the Anchor Loop Expansion.
Minimum Return Adjustment:	Means the adjustment, if any, calculated pursuant to Section 6.2.6 and Section 8 and the method provided in Schedule 12.
NEB Cost Recovery Charge:	Means all amounts invoiced to TPTM, or to Kinder Morgan Canada Inc., as operator of the System, pursuant to the NEB Cost Recovery Regulations.
Non-Controllable Costs:	Means the costs calculated pursuant to Section 15.2.
Non-Routine Adjustment:	Means the adjustment, if any, calculated pursuant to Section 13, including those shown in Schedule 13 and in subparts 7.1 to 7.5 of Appendix 7.
Operating and Maintenance Costs:	Means the dollar amount of costs determined pursuant to Section 5.3 and adjusted pursuant to Sections 6.2.2 and 6.2.3.
Operating Capacity:	Means 95% of Design Capacity. The Operating Capacity of the System is, as of January 1, 2006, 225 kbpd, and following the completion of the Expansions, is planned to be equal to the capacities set forth in the definitions of Pump Station Expansion and Anchor Loop Expansion.
Party:	Means TPTM and CAPP and "Parties" means both of them.
Petroleum:	Has the meaning given to it from time to time in the Petroleum Tariff.
Petroleum Loss Allowance:	Means the dollar amount of costs determined pursuant to Section 4.2(b).
Petroleum Tariff:	Means TPTM's rules and regulations governing the transportation of petroleum and Toll schedules, as approved by the NEB from time to time;
Prior ITS	Means the dollar amount of costs determined pursuant to Section 5.4 and as shown in Appendix 8 and subparts

Adjustments:	8.1 to 8.3 and Appendix 7, subparts 7.1 to 7.5.
Pump Station Expansion:	Means the facilities to be added to the Trans Mountain System to increase its Operating Capacity to 260,000 bpd, as authorized by NEB Order XO-T099-15-2005, and includes the pump station which may be constructed pursuant to Section 14.4
Rate Base:	Means the accumulated original capital cost of the assets comprising the System, net of accumulated Depreciation and Amortization and deferred income taxes, plus Working Capital.
Rate Base Adjustments:	Means the dollar amount to be added to the Rate Base for the Pump Station Expansion and the Anchor Loop Expansion pursuant to Section 6.2.1 as determined pursuant to Section 14 and as summarized in subschedules 4.1 and 4.2.
Reference Line Temperature Agreement:	Means the agreement set forth in Schedule 23.
Return Component:	Means the dollar amount of costs determined pursuant to Section 5.2.
Revenue Requirement:	Means the total revenue to be recovered from the transport or handling of Petroleum on the System in any year determined pursuant to Sections 4, 5 and 6 and summarized in Schedule 1.
ROE:	Means return on equity.
Salaries and Wages:	Means the direct costs of Employee compensation, including the cost of Employee benefits but excluding the cost of stock options or other discretionary payments.
Service Standards:	Means the standards set forth in Schedule 22.
Shippers:	Has the meaning given to it in Section 1.4.
System:	Has the meaning given to it in Section 1.2.
System Throughput	Means, for any year of the Term, TPTM's forecast of the

Level:	System throughput, based on 92.5% of the Design Capacity, plus volumes received into the System at Kamloops, and reflecting the forecast mix of receipt and delivery points on the System and the forecast proportion of Heavy Oil for that year, as summarized in Schedule 2.
Term:	Has the meaning given to it in Section 3.1.
Toll Trending:	Means the dollar amount of costs determined pursuant to Section 4.5 and the method provided in Schedule 3.
Toll:	Means the dollar amount per volume unit of Petroleum established by TPTM and as agreed to by CAPP from time to time, in accordance with the terms of this 2006 ITS and the System Throughput level shown in Schedule 2, and, for 2006, as calculated in Schedules 14, 15, 16, 17, 18 and 19, to transport Petroleum from a specified point of receipt to a specified point of delivery through the System and published in a Petroleum Tariff.
TPTM or Carrier:	Has the meaning given to it in Section 1.1.
Transportation Revenue Adjustment:	Means the dollar amount of the adjustment, if any, calculated pursuant to Section 6.2.5 and Section 11 and the method provided in Schedule 8.
Working Capital:	Means, for any year, the sum of: (a) The total dollar amount of Operating and Maintenance Costs for that year, minus insurance costs for that year, plus Flow Through Costs for that year, all multiplied by 15 and divided by 365; and (b) The average of the opening and closing inventory costs and prepaid charges for that year.

3.3 Whenever the singular or plural is used in this 2006 ITS, it shall be construed as meaning the plural or singular as the context requires.

3.4 Any references to "current" practices or level of service in this 2006 ITS shall be construed as meaning practices or levels of service prevailing as of January 1, 2006 at 7:00 am., with the exception of the Petroleum Tariff approved by the NEB on August 31, 2006 by Order TO-02-2006.

3.5 The Petroleum Tariff is subject to the approval of the NEB in accordance with the *National Energy Board Act* (Canada). At any time during the Term TPTM may apply for NEB approval of amendments to the Petroleum Tariff which are not inconsistent with the terms of this 2006 ITS and shall provide CAPP with a copy of such proposed amendments. Any amendments to the Petroleum Tariff shall be effective on approval by the NEB.

3.6 The following Schedules and Appendices shall form part of this 2006 ITS, provided that the numerical values contained in the Schedules and Appendices for years post 2006 are illustrative only unless otherwise stated.

Schedule 1	Summary of Revenue Requirement for 2006 to 2010
Schedule 2	Summary of Forecast Throughput Volumes for Tolls
Schedule 3	Method for Calculation of Toll Trending used in Revenue Requirement
Schedule 4	Summary of Rate Base Adjustments
Schedule 5	Method for Calculation of GDDP and the GDPP Adjustment
Schedule 6	Summary of Flow Through Costs and Adjustments
Schedule 7	Method for Calculation of the Capacity Incentive Adjustment
Schedule 8	Method for Calculation of the Transportation Revenue Adjustment
Schedule 9	Method for Calculation of the Capacity Penalty Adjustment
Schedule 10	Method for Calculation of the Depreciation and Amortization
Schedule 11	Method for Calculation of Income Tax Provision
Schedule 12	Method for Calculation of the Minimum Return Adjustment
Schedule 13	Summary of Non-Routine Adjustments
Schedule 14 to 20	2006 Tolls and Tariffs Explanatory Notes and Calculations
Schedule 21	Commodity Surcharge Methodology
Schedule 22	Service Standards
Schedule 23	Reference Line Temperature Agreement
Appendix 1	Table of Pipeline Capacity for Current System, Pump Station and Anchor Loop Expansions
Appendix 2	Table for Calculation of Power Costs
Appendix 3	Capital Risk Sharing Amounts and Calculations
Appendix 4	Carrying Charge Rate used for Calculating Adjustments
Appendix 5	Performance Measures and NEB Compliance Reporting
Appendix 6	Monitoring Forecast Income Tax Cross Over Point
Appendix 7	Calculation of 2005 Individual Non-Routine Adjustments
Appendix 8	Summary of Prior ITS Adjustments from 2001 Incentive Toll Settlement

The schedules attached hereto provide the methodology for calculation of the amounts defined within this 2006 ITS. The appendices provide supporting calculation, documentation, and compliance reporting to enhance the schedules and meet the annual NEB filing guidelines.

In the event of a conflict between the body of this 2006 ITS and the methodology set forth in the Schedules and the Appendices, the methodology set forth in the Schedules and Appendices will govern, provided that (except with respect to calendar year 2006) the numbers used in the sample calculations in the Schedules are examples only and any disagreement between any such number and any other number in this 2006 ITS or any other Schedule shall not be a conflict.

4. REVENUE REQUIREMENT - GENERAL

4.1 TPTM will determine a Revenue Requirement to be recovered through Tolls for each calendar year of the Term in accordance with the provisions of this Section 4 and Sections 5 and 6.

4.2 TPTM will, subject to the provisions of this 2006 ITS, estimate the Flow Through Costs for each year of the Term. The variance, whether positive or negative, between the estimated Flow Through Costs and the actual Flow Through Costs incurred during that year will, subject to the provisions of this 2006 ITS, form an Adjustment to the Revenue Requirement for the following year. The method of calculation of the power costs and adjustments is provided in sub-schedule 6.1 with a supporting table of power consumption and costs provided on Appendix 2. The method of calculation of the Petroleum Loss Allowance and adjustments are provided on sub-schedule 6.2.

Flow Through Costs means the sum of the following costs required for efficient operation of the System:

(a) the cost of power (including demand, consumption, transmission and other charges) incurred for throughput levels up to, but not exceeding 92.5% of Design Capacity, provided that when Actual Throughput exceeds 92.5% of Design Capacity, the power costs to form part of the Flow Through Costs will be adjusted as set out in Section 10.2.

(b) a Petroleum Loss Allowance, calculated as the cost of Petroleum purchased by TPTM, net of the proceeds of any sale of Petroleum retained by TPTM pursuant to the Rules and Regulations, to replace volumes lost from the System as a result of operations, including volumetric shrinkage or intermixing while in transit; and

(c) the NEB Cost Recovery Charge.

4.3 For each year of the Term, Depreciation and Amortization will be determined by the application of depreciation rates as approved by the NEB from time to time, to TPTM's plant accounts as maintained in accordance with (a) the *Oil Pipeline Uniform Accounting Regulations*, as amended or replaced from time to time, and (b) GAAP. During the Term, TPTM will not initiate an application to the NEB to amend or revise the applicable depreciation rates without the prior consent of CAPP. The method of calculation of the Depreciation and Amortization is provided on Schedule 10.

4.4 For each year of the Term, the Income Tax Provision will be determined by applying statutory income tax rates (applicable in the provinces of Alberta and British Columbia) and large corporations tax to the portion of the Return Component attributable to the equity portion of the Financial Parameters for the year. Calculation of the Income Tax Provision will utilize the flow through methodology of accounting for income taxes, and applicable taxable differences, appropriately adjusted to a pre-tax amount, in a manner consistent with that approved by the NEB in its RH-3-93 Decision. The method of calculation of the Income Tax Provision is set out in Schedule 11.

4.5 For each year of the Term, Toll Trending will be applied to partially levelize the Revenue Requirement. TPTM will calculate Toll Trending so as to provide the Shippers with a positive return on a net present value basis (as of January 1, 2006) of approximately $1 million (before tax) over the first four years, using a discount rate of 10%. The effect of Toll Trending on annual Revenue Requirements during the Term will be in accordance with the method set out in Schedule 3.

5. 2006 REVENUE REQUIREMENT

5.1 The Revenue Requirement for 2006 will be determined as the sum of the following components, each as described herein:

(a) Return Component;

(b) Operating and Maintenance Costs;

(c) Flow Through Costs;

(d) Depreciation and Amortization;

(e) Prior ITS Adjustments;

(f) Income Tax Provision; and

(g) Toll Trending.

The determination of the Revenue Requirement for 2006 is as set out in Schedule 1.

5.2 The Return Component for 2006 will be calculated by application of the following parameters (the "**Financial Parameters**"), to TPTM's 2006 Rate Base:

(a) a deemed capital structure composed of 45% equity and 55% debt;

(b) an ROE of 10.75%; and

(c) a cost of debt of 6.0%.

5.3 Operating and Maintenance Costs for 2006, inclusive of property taxes, but exclusive of the Flow Through Costs will be $32.234 million, plus Salaries and Wages of $25.774 million for a total of $58.008 million.

5.4 Prior ITS Adjustments will be determined for 2006 as the amounts to be credited to or recovered from Shippers resulting from the provisions of the 2001 Incentive Toll Settlement. The calculation of Prior ITS Adjustments is as set out in Appendix 8 (and subparts 8.1 to 8.3) and Appendix 7, subparts 7.1 to 7.5.

6. REVENUE REQUIREMENT 2007 THROUGH 2010

6.1 The Revenue Requirement for each of the years 2007 through 2010 will be determined by applying adjustments to, or re-calculating elements of, the prior year's Revenue Requirement in the manner set out in Sections 4 and 5 and this Section 6.

6.2 The following adjustments will be utilized in the calculation of the Revenue Requirement for the years 2007 through 2010:

6.2.1 The Rate Base will be adjusted by an amount equal to the Rate Base Adjustment, determined in accordance with the provisions of Section 14, made as of the actual In Service Dates of the Pump Station Expansion and the Anchor Loop Expansion.

6.2.2 The Operating and Maintenance Costs will be adjusted by an amount equal to:

(a) The forecast GDPP and any GDPP Adjustment applied to Salaries and Wages; and

(b) 75% of the forecast GDPP and any GDPP Adjustment applied to Operating and Maintenance Costs other than Salaries and Wages.

6.2.3 The Operating and Maintenance costs, inclusive of property taxes and Salaries and Wages will be adjusted for the impacts of the Expansion as of the actual In Service Dates of the Pump Station Expansion and the Anchor Loop Expansion.

(a) For the Pump Station Expansion, the additional costs, stated in 2006 dollars, will be as follows:

(i) additional Operating and Maintenance Costs, inclusive of property taxes but exclusive of salaries and wages of $2.451 million;

(ii) additional salaries and wages of $1.815 million; and

(b) For the Anchor Loop Expansion, the additional costs, stated in 2006 dollars, will be as follows:

(i) additional Operating and Maintenance Costs, inclusive of property taxes but exclusive of salaries and wages of $2.177 million; and

(ii) additional salaries and wages of $0.848 million.

(c) A provision for one time hydro-test costs will be added to the Revenue Requirement as of the actual In Service Dates of the Pump Station Expansion, in the amount of $1.6 million and the Anchor Loop Expansion, in the amount of $2.1 million.

These Operating and Maintenance Costs will be escalated to dollars of the day using the cumulative impact of GDPP to the In Service Date of the Expansion and the appropriate factor as defined in section 6.2.2. These costs are to be included in the calculation of Operating and Maintenance Costs from that year forward. Illustration of the proposed treatment and calculation are provided on Schedule 5.

6.2.4 The Flow Through Costs will, subject to Section 4.2, be adjusted by an amount determined as the difference, either positive or negative, between the forecast Flow Through Cost used in the previous year's Revenue Requirement and the actual Flow Through Costs for that year.

6.2.5 A Transportation Revenue Adjustment to be determined in accordance with the provisions of Section 11 and Schedule 8.

6.2.6 A Minimum Return Adjustment, to be determined in accordance with the provisions of Section 8 and as illustrated in Schedule 12.

6.2.7 A Capacity Incentive Adjustment, to be determined in accordance with the provisions of Section 10 and as illustrated in Schedule 7.

6.2.8 A Capacity Penalty Adjustment, to be determined in accordance with the provisions of Section 12 and as illustrated in Schedule 9.

6.2.9 Non-Routine Adjustments, to be determined in accordance with the provisions of Section 13 and as summarized in Schedule 13, including the amounts calculated for inclusion in the 2006 Tolls provided for the Individual Non-Routine Adjustments in subparts 7.1 to 7.5 of Appendix 7.

6.2.10 A Toll Trending adjustment, to be determined in accordance with the provisions of Section 4.5 and the method in Schedule 3.

6.3 Carrying Charges will be applicable to all adjustments made pursuant to Section 6.2 (except Section 6.2.8) and as illustrated in Appendix 4.

6.4 The method of calculating the Revenue Requirement and adjustments for each of the years 2007 through 2010 are as set out in Schedules 3 through 13 and supporting Appendices.

7. DETERMINATION OF TOLLS

7.1 TPTM will calculate Tolls to recover the Revenue Requirement for each year of the Term at the System Throughput Level for that year, as illustrated in Schedule 2.

7.2 The timing and manner of annual Toll adjustments will be as set out in the provisions of Section 18.

7.3 Toll surcharges and surcredits applicable to the transport of Petroleum will be revised so as to apply such surcharges and surcredits only to the transmission component of Tolls. Details and explanation for the Toll calculations for 2006 are provided in Schedules 14 through 20. The method of calculating Toll surcharges and surcredits for each of the years 2007 through 2010 are as set forth in Schedule 21. The applicable surcharges and surcredits may be modified by the provisions of the Service Standards, provided that changes to the surcharges and surcredits applicable to the transport of Petroleum, or other changes to the applicable toll design, will be intended to be revenue neutral to TPTM.

8. MINIMUM RETURN

8.1 If, for any year of the Term, the actual ROE (including all incentive and penalty amounts recognized for that year in accordance with GAAP) earned by TPTM is less than 7.0%, TPTM will calculate an adjustment (the "**Minimum Return Adjustment**") to the following year's Revenue Requirement to recover, on an after-tax basis, the difference between 7.0% and the actual ROE achieved for the year.

8.2 The method of calculating the actual ROE, and any adjustment resulting therefrom, is as set out in Schedule 12.

9. DEFERRAL ACCOUNTS

9.1 The Company shall be authorized to establish deferral accounts to record the following amounts, including Carrying Charges thereon pursuant to Section 6.3, to be implemented as adjustments to Tolls as defined and more fully described within each Section noted as follows:

(a) Flow Through Cost adjustment, Section 6.2.4 for:

(i) Power Costs

(ii) Petroleum Loss Allowance, Section 4.2(b)

(iii) NEB Cost Recovery

(b) Operating and Maintenance Cost adjustments, Section 6.2.2

(c) Toll Trending, Section 6.2.10

(d) Minimum Return Adjustment, Section 6.2.6

(e) Capacity Incentive adjustment, Section 6.2.7

(f) Transportation Revenue Adjustment, Section 6.2.5

(g) Capacity Penalty Adjustment, Section 6.2.8

(h) Non-Routine Adjustment, Section 6.2.9

10. CAPACITY INCENTIVE ADJUSTMENT

10.1 For each month that Actual Throughput exceeds 92.5% of the Design Capacity, TPTM will calculate the Capacity Incentive Adjustment, being an amount equal to 25% of toll revenue derived from the incremental throughput, in accordance with the method provided in Schedule 7. The remainder of such revenue will be for the account of TPTM.

10.2 For each month in which Actual Throughput exceeds 92.5% of the Design Capacity, TPTM will calculate (in accordance with the method shown in Sheet 2 of Schedule 7) the power costs attributable to the transportation of throughput exceeding 92.5% of the Design Capacity. 25% of such costs will be added to and form part of the Flow Through Cost adjustment for the year pursuant to Section 6.2.4, and the remaining 75% of such costs will be to the account of TPTM.

11. TRANSPORTATION REVENUE ADJUSTMENT

11.1 The Transportation Revenue Adjustment will be equal to the actual Toll revenue, minus the Toll revenue that would have been generated had throughput been at the System Throughput Level used to calculate the Tolls in that year. The Transportation Revenue Adjustment may be positive or negative.

11.2 For greater certainty, the Transportation Revenue Adjustment shall be calculated so as to avoid the duplication or double counting of any other adjustment, including any incentive or penalty, provided for in this 2006 ITS.

11.3 The method of calculating the Transportation Revenue Adjustment is provided in Schedule 8.

12. CAPACITY PENALTY ADJUSTMENT

12.1 In any month for which TPTM has declared Apportionment and in which the throughput is less than 90% of Design Capacity an amount will be calculated pursuant to this Section 12 as the Capacity Penalty Adjustment. For purposes of this Section 12, "throughput" for a month will mean the volumes injected into the pipeline at the receipt points of Edmonton and Edson in that month.

12.2 The Capacity Penalty Adjustment will be determined by calculating the Actual Throughput in the applicable month as a percentage of the Design Capacity and if that percentage is less than 90, subtracting it from 90 and multiplying the result by $60,000, to a maximum of $300,000 per month.

12.3 The Capacity Penalty Adjustment will not apply to the extent that the failure to attain throughput (as calculated in Section 12.1 equal) to 90% of Design Capacity is attributable to the failure of a Shipper or Shippers to tender nominated volumes in accordance with the schedule established by TPTM, the failure of a feeder or delivery system to deliver Petroleum to the System as scheduled, or an event of *Force Majeure*.

12.4 The method of calculating the Capacity Penalty Adjustment is provided in Schedule 9.

13. NON-ROUTINE ADJUSTMENTS

13.1 A Non-Routine Adjustment will mean:

(a) Subject to Section 14.4, the cost arising from the construction of the pump station referred to in that Section;

(b) Costs arising from changes in programs, required NEB reporting or the installation of facilities ordered by the NEB where the matter was not initiated by TPTM or its Affiliates or change in costs resulting from legislation, regulations, orders or directions by any government authority which result in additional safety or environmental requirements, practices or procedures for TPTM or its Affiliates, but excluding changes in asset retirement obligations unless directed by the NEB;

(c) Increases in costs from programs or facilities requested by shippers, and agreed to by shippers, provided that any shipper may require determination of whether such costs should be recovered through tolls on a "rolled in" basis or on a "stand alone" basis. If stand alone, costs will be billed directly to the Shipper in question;

(d) Increases in costs as a result of major uninsured losses exceeding $5.0 million, subject to the requirements of Section 24.2;

(e) The costs of programs necessary to address new or unanticipated failure mechanisms after commencement of this 2006 ITS which may significantly impact upon the integrity of the pipeline;

(f) The amount of additional income tax payable as a result of repayment of previously accrued timing differences, if in, any calendar year, the calculation of income taxes reaches the crossover point where depreciation expense exceeds allowable capital cost allowance. TPTM will provide CAPP with an annual update, as provided for in Appendix 6;

(g) The cost of audits reimbursed to CAPP pursuant to Section 22.8;

(h) A change in costs or revenues as a result of a change in the Reference Temperature Agreement or any change in the viscosity standards for crude petroleum on the Enbridge Pipeline System including as a result of changes in reference temperatures or otherwise; or

(i) Adjustments for Edmonton terminalling revenues, as described in the first bullet of Appendix 7 and illustrated in Appendix 7.1.

13.2 A Non-Routine Adjustment shall be the adjustment to Tolls necessary to permit TPTM to recover or credit any revenue adjustment resulting from the occurrence of an event as described in this Section 13 over the appropriate time period.

13.3 The capital component of any Non-Routine Adjustment will be calculated using the applicable provisions of Revenue Requirement as set out in Section 5.1 (other than the Return Component). Non-Routine Adjustments will utilize the prevailing NEB ROE determined pursuant to the methodology established in the RH-2-94 Decision unless otherwise negotiated and agreed to by CAPP and TPTM.

14. RATE BASE ADJUSTMENTS

14.1 Upon completion of each of the Pump Station Expansion and the Anchor Loop Expansion, TPTM will calculate the Rate Base Adjustment. The Rate Base Adjustment will be added to the Rate Base (and be used in the calculation of the Revenue Requirement) as of the In Service Date of the applicable Expansion and continue to be reflected in the Rate Base in all subsequent years of the Term.

14.2 The effect of the Rate Base Adjustment for the Pump Station Expansion and the Anchor Loop Expansion will be an increment to the Revenue Requirement determined by calculating the elements of the Revenue Requirement, inclusive of Operating and Maintenance Costs, as set out in Section 5, and utilizing the capital cost for the Rate Base Adjustment as determined in accordance with Section 14.3, except that the cost of debt specified in Section 5.2(c) will be increased by 40% of the amount, if any, by which the AL Reference Rate exceeds the Base Reference Rate.

14.3 The Rate Base Adjustment for each of the Pump Station Expansion and the Anchor Loop Expansion will be determined as:

(a) The actual capital cost of each Expansion, as adjusted in accordance with the provisions of Section 15 and the method in sub-schedules 4.1 and 4.2 of Schedule 4; provided that

(b) The adjusted capital cost determined pursuant to this Section 14.3 will be further adjusted downward if the Expansion, when fully in service, fails to provide an intended Operating Capacity (assuming a 20% Heavy Oil component of throughput) of at least 260,000 barrels per day following completion of the Pump Station Expansion and 300,000 barrels per day following completion of the Anchor Loop Expansion, as determined in a Capacity Test or re-test conducted pursuant to Section 16. In that event, the capital cost for either Expansion will be determined by multiplying the amount determined under Section 14.3(a) by the ratio of the actual Operating Capacity attained following each Expansion to the intended Operating Capacity of each Expansion as defined above.

14.4 TPTM shall have the right (subject to the approval of CAPP, not to be unreasonably withheld) to construct one additional intermediate pump station as part of the Pump Station Expansion. The cost of construction of that pump station will, at TPTM's option, either be treated as a Non-Routine Adjustment pursuant to Section 13.1(a), or be the subject of a Rate Base Adjustment pursuant to this Section 14. If the latter approach is used, then the parameters for the Pump Station Expansion set forth in Section 15 (including the estimated amount of Non-Controllable Costs, the ECC, the P10 Amount and the P90 Amount) shall be amended to reflect the increase in scope of the Pump Station Expansion. If TPTM decides that it will construct that additional pump station, it will deliver a notice to that effect, including its election under the second sentence above, to CAPP no later than December 31, 2006. If the additional pump station is constructed, the Rate Base Adjustment for the Pump Station Expansion to be made on the In Service Date of that additional pump station will reflect the depreciated value on that date of the assets comprising the Pump Station Expansion which came into service prior to that date.

14.5 Notwithstanding the provisions of Section 18, TPTM may seek the approval of the NEB for adjustment of Tolls reflecting the Rate Base Adjustment to take effect as of the first day of the month immediately following the In Service Date of either Expansion.

15. CAPITAL COST CONTROL INCENTIVE

15.1 TPTM has undertaken a probabilistic analysis (shown in Appendix 3) of the costs for the Pump Station Expansion and the Anchor Loop Expansion and has produced the following cost estimates:

	Pump Station Expansion (million)	Anchor Loop Expansion (million)
Expected Value	$226.4	$438.4
Estimated amount of Non-Controllable Costs	$66.8	$111.2
Estimated amount of	$159.6	$327.2

Controllable Costs ("**ECC**")		
P10 amount of Controllable Costs ("**P10 Amount**")	$129.3	$313.9
P90 amount of Controllable Costs ("**P90 Amount**")	$198.4	$340.2

15.2 The Non-Controllable Costs are defined as:

15.2.1 In respect of the Pump Station Expansion, the power infrastructure costs (for clarity includes power lines, substations, interconnections, commissioning, project management, development and power acquisition specialists for a total estimate of $61.2 million) plus AFUDC (estimated at $5.6 million);

15.2.2 In respect of the Anchor Loop Expansion, 55% of the base lay costs (estimated at $56.6 million), 55% of the unit price items (estimated at $24.1 million), 100% of cost of the river crossing and 39% of right-of-way restoration (estimated at $22.5 million) and financing fees (estimated at $3.5 million) plus AFUDC (estimated at $4.5 million); and

15.2.3 Any additional AFUDC pursuant to Section 15.3

15.3 TPTM has, to September, 2006, pursued an advanced schedule for the construction of the Anchor Loop Expansion. That advanced schedule has required the pre-ordering of line pipe, accelerated manufacturing and associated engineering and management time. The Anchor Loop Expansion will be constructed according to the advanced schedule if the Mount Robson Provincial Park boundary adjustment program is approved by the B.C. legislature in sufficient time to permit construction in accordance with the advanced schedule. If the advanced schedule cannot be achieved, TPTM estimates that such pre-design and pre-purchase is likely to cause $4.9M of incremental AFUDC. CAPP agrees that in the event that the Anchor Loop Expansion is not built to the advanced schedule, the incremental AFUDC associated with the pursuit of the advanced schedule shall be treated as a Non Controllable Cost. TPTM will pursue the minimization of such AFUDC and will discuss the minimization with CAPP on a timely basis following October of 2006.

15.4 The capital costs of the Rate Base Adjustment for each of the Pump Station Expansion and Anchor Loop Expansion will include the actual amount of Non-Controllable Costs.

15.5 The capital cost of the Rate Base Adjustment for each of the Pump Station Expansion and Anchor Loop Expansion will include an amount for Controllable Costs calculated as follows:

(1) if the actual Controllable Costs (the "**ACC**") incurred in the construction of the Expansion is greater than the P90 Amount for that Expansion, the amount to be included in respect of Controllable Costs for that Expansion shall equal:

ECC + [0.75 x (P90 Amount -ECC)] + [0.25 x (ACC –P90 Amount)]

(2) if the ACC is equal to or less than the P90 Amount for that Expansion but equal to or greater than the ECC for that Expansion, the amount to be included in respect of Controllable Costs for that Expansion shall equal:

ECC + 0.75 x (ACC – ECC)

(3) if the ACC is less than the ECC but equal to or greater than the P10 Amount, the amount to be included in respect of Controllable Costs for that Expansion shall equal:

ACC + 0.25 x (ECC – ACC)

(4) if the ACC is less than the P10 amount, the amount to be included in respect of Controllable Costs for that Expansion shall equal:

ACC + [0.25 x (ECC - P10 Amount)] + [0.10 x (P10 - ACC)]

The following chart illustrates the sharing of incremental savings of Controllable Costs when the ACC is less than the ECC:

	Each incremental dollar saved shall be applied as follows:	
	To Shipper Account	**To TPTM Account (as an addition to Rate Base)**
ACC is P10 or less	90¢	10¢
ACC is between P10 and ECC	75¢	25¢

The following chart illustrates the sharing of incremental Controllable Costs when the ACC exceeds the ECC.

	Each incremental dollar spent shall be applied as follows:		
	To Shipper Account	**To TPTM Account (as an addition to Rate Base)**	**Deferred to Future Expansion**
ACC is between ECC and P90	25¢	75¢	
ACC is P90 or more	50¢	25¢	25¢

For greater certainty, the risk sharing formula and costs are presented in Appendix 3.

15.6 The portion of the Controllable Costs that exceeds P90 will be deferred to a subsequent expansion and incorporated into the Rate Base of that subsequent expansion under the following conditions:

15.6.1 the expansion is designed to add incremental pipeline capacity of not less than 50,000 bpd; and

15.6.2 the expansion is placed in service no later than three (3) years following the In Service Date of the Anchor Loop Expansion.

If the conditions set forth in Sections 15.6.1 and 15.6.2 are not satisfied, no amount in respect of those costs will be included in the revenue requirement.

15.7 If the actual Controllable Costs incurred in the construction of the Expansion is greater than the P90 Amount for that Expansion the amount to be deferred to a Future Expansion in accordance with Section 15.6 shall equal:

[0.25 x (ACC –P90 Amount)]

16. CAPACITY TESTING

16.1 The increase in Operating Capacity provided by either or both of the Pump Station Expansion and the Anchor Loop Expansion may be tested to confirm the actual Operating Capacity of the System following the completion of each Expansion.

16.2 TPTM will provide CAPP with not less than sixty (60) days notice of the anticipated and not less than thirty (30) days notice of the actual In Service Dates of each Expansion. Within nine (9) months of the In Service Date of either Expansion, the Parties may request that a Capacity Test be conducted to confirm the Operating Capacity of the System following such Expansions.

16.3 The Parties will use all reasonable efforts to arrange a Capacity Test within sixty (60) days of a request for a test, or a re-test in accordance with this Section. The Parties will use all reasonable efforts to arrange a suitable throughput schedule and configuration with a view to provide a Heavy Oil component in the order of 20%, or such other percentage as agreed by the Parties, in order to allow for an uninterrupted Capacity Test for one typical schedule of delivery volumes, currently defined as a six (6) day cycle but may vary as agreed by the Parties based on delivery requests and Heavy Oil component.

16.4 The Capacity Test will be successful if TPTM achieves throughput of not less than 102.5% of the intended Operating Capacity. For greater certainty, the intended Operating Capacity with a Heavy Oil Component of 20% following completion of the Pump Station Expansion is 260,000 barrels per day and following completion of the Anchor Loop Expansion is 300,000 barrels per day (with each case subject to the percentage of Heavy Oil, line temperature and the provisions of the Reference Temperature Agreement). For purposes of this Section 16.4, "throughput" for the period covered by the Capacity Test will mean the volumes injected into the pipeline at the receipt points of Edmonton and Edson in that period.

16.5 If a Capacity Test is not successful, TPTM may conduct a re-test of the System capacity upon demonstrating to CAPP a reasonable justification and prevailing market conditions permit the availability of crude for such a re-test. Reasonable justification for a re-test will include, but not be limited to, such factors as a change to or modification of System facilities by TPTM, equipment failure during the test, or a change in batch line up resulting from Shipper request or failure by a Shipper or Shippers to nominate and tender volumes as scheduled. Any re-test will be conducted in accordance with the provisions of this Section.

16.6 Following the construction of the pump station referred to in Section 14.4, TPTM may at its option conduct a re-test of the System capacity in accordance with the provisions of this Section.

16.7 Following any re-test pursuant to Sections 16.5 or 16.6, the Rate Base Adjustment calculated pursuant to Section 14.3(b) shall be recalculated taking into account the Operating Capacity determined in the re-test.

17. IN SERVICE DATES

17.1 TPTM will use all reasonable efforts to achieve the target In Service Dates for the Pump Station Expansion and the Anchor Loop Expansion. The target In Service Dates of the Pump Station Expansion and the Anchor Loop Expansion will be April 1, 2007 and January 1, 2009, respectively, unless the Anchor Loop Expansion is constructed according to the advanced schedule.

17.2 If the In Service Date of either Expansion differs from the applicable target date, any Rate Base Adjustment and consequent adjustment to tolls reflected in the costs of such Expansion will be advanced or delayed from the target In Service Date in accordance with the Rate Base Adjustment as set out in Section 14.

18. ANNUAL TOLL ADJUSTMENTS

18.1 The Tolls in effect as of the end of each calendar year of the Term will be deemed to be interim as of January 1 of the following year.

18.2 Tolls to be in effect for each year of the Term will be calculated in accordance with the provisions hereof, based on the System Throughput Level for that year. TPTM will use all reasonable efforts to provide CAPP with a draft of that year's toll adjustment no later than February 15, and the Parties will use all reasonable efforts to agree on the form and content of the annual Toll adjustments by March 5.

18.3 The Parties intend that final Tolls for any year of the Term designed to recover the Revenue Requirement for that year will take effect as of April 1. Any over or under-recovery of the Revenue Requirement during the time that interim Tolls are in effect will be recovered over the remainder of the year in question.

18.4 The Parties intend that an application for approval of final Tolls for each year will be filed with the NEB prior to March 31 of that year.

19. AMENDMENT OR MODIFICATION OF 2006 ITS

19.1 In the event of:

(a) the construction of a Major Expansion;

(b) a change in the GDPP of greater than 10% in any year; or

(c) an event beyond the control of TPTM that reduces the Operating Capacity of the System to less than 50% of Design Capacity for a period of not less than 30 consecutive days;

the Parties will meet to negotiate, in good faith, a mutually-acceptable amendment to, or modification of, this 2006 ITS.

19.2 Either Party may request a meeting to commence negotiations upon the occurrence of an event listed in Section 19.1. The Parties will meet to commence negotiations no later than 45 days following such an event.

19.3 TPTM will not transfer the System into an income trust without first receiving approval from CAPP.

19.4 Any amendment to, or modification of, this 2006 ITS will be agreed to by both Parties and be subject to the approval of the NEB.

20. TRANSACTIONS WITH AFFILIATES

20.1 TPTM will maintain books of account for the System in accordance with the requirements of the *Oil Pipeline Uniform Accounting Regulations*, as amended or replaced from time to time, and any applicable orders or directives of the NEB.

20.2 All transactions with Affiliates will reflect the fair value of goods or services provided to or acquired from such Affiliate and in accordance with TPTM's Cost Allocation Study filed with the NEB in July, 2002. TPTM will notify CAPP of all such transactions taking place outside of the ordinary course of operating the System.

20.3 TPTM will neither offer nor provide transportation services, access to, or use of any assets or facilities forming part of the System to an Affiliate on terms and conditions that are preferable to those stated in the Petroleum Tariff or provided to other Shippers in similar circumstances. Any sale or removal of an asset from the System to an Affiliate or third party, that has the affect of providing transportation services, access to, or use of any assets at conditions other than stated in the Petroleum Tariff, will first require the approval from CAPP.

20.4 TPTM will not disclose to an Affiliate, or to any other person, confidential or proprietary information provided to it by a shipper unless:

(a) TPTM has received consent from such shipper;

(b) Disclosure of the confidential or proprietary information is required by law or by order of any court or administrative tribunal exercising jurisdiction over TPTM; or

(c) the confidential or proprietary information is, or becomes, part of the public domain other than through the action of TPTM.

Notwithstanding the foregoing, TPTM may disclose such information to Kinder Morgan Canada Inc. (the operator of the System) and its officers, employees and agents who have a need to know such information. The provisions of Sections 20.4, 20.5 and 20.6 will apply to any person to whom such disclosure is made hereunder.

20.5 TPTM will ensure that all of its officers and employees and all officers and employees of its Affiliates are aware of and comply with the requirements of this Section.

20.6 If a shipper or CAPP alleges or complains that TPTM has breached any provision of this Section, TPTM will meet with the complaining shipper or CAPP in an attempt to resolve concerns raised. If a satisfactory resolution cannot be agreed upon, the dispute resolution provisions of Section 23 will apply, provided however that a complaining shipper may have recourse to the NEB without the participation of CAPP.

21. FILING REQUIREMENTS

21.1 TPTM will seek exemption from the NEB in respect of the requirement for TPTM to file financial forecasts and financial surveillance reports (consistent with the relief granted pursuant to Board Order TO-1-2001), and will instead seek the approval of the NEB to file those forecasts and reports referred to in Appendix 5, and CAPP will support TPTM's application in that regard.

22. AUDIT REQUIREMENTS

22.1 Upon reasonable notice to TPTM, CAPP may elect to have an audit performed to confirm the reasonableness of the costs attributable to operation of the System and to confirm TPTM's compliance with the provisions of Sections 20.1 to 20.3 hereof.

22.2 Upon reasonable notice to TPTM, and no more than 2 years after the applicable In Service Date, CAPP may elect to have an audit performed to confirm TPTM's calculation of the Rate Base Adjustment for the Pump Station Expansion pursuant to Section 15.

22.3 Upon reasonable notice to TPTM, and no more than 1 year after the applicable In Service Date, CAPP may elect to have an audit performed to confirm TPTM's calculation of the Rate Base Adjustment for the Anchor Loop Expansion pursuant to Section 15.

22.4 The audits referred to in Sections 22.1, 22.2 and 22.3 will be carried out in accordance with CICA Handbook Section 5805.

22.5 The auditor selected by CAPP pursuant to Section 22.1 must either be a firm of chartered accountants, or auditors directly employed by a shipper. Auditors directly employed by the shipper must have appropriate professional qualifications to perform such audits. The audit must be conducted during normal business hours on such days as may be agreed to by the Carrier.

22.6 TPTM will provide such auditors with reasonable access to the source data necessary for the conduct of the audit, and to TPTM's audit files. The auditors will not be provided with access to any records held by the Carrier's contractors, subcontractors or suppliers.

22.7 Persons involved in the audit will not disclose to any person, confidential or proprietary information provided to it by TPTM and will require (if a firm of chartered accountants is used) that its auditors sign an agreement to keep confidential all such information provided by TPTM, unless:

(a) TPTM has consented to the disclosure of such information;

(b) disclosure of the confidential or proprietary information is required by law or by order of any court or administrative tribunal acting within its jurisdiction; or

(c) such confidential or proprietary information is, or becomes, part of the public domain, other than through the action of the auditors or CAPP.

22.8 TPTM will reimburse CAPP for the direct cost incurred, or agreed to by CAPP, in respect of any audits undertaken on its behalf pursuant to this Section 22, provided that the costs of such reimbursement, together with carrying charges, shall be recovered by TPTM as a Non-Routine Adjustment.

23. DISPUTE RESOLUTION

23.1 The Parties agree that any requirement of or obligation set out in this 2006 ITS to agree to, concur with, or negotiate the effect of any matter identified herein as requiring such agreement concurrence or negotiation will be construed as an obligation to act in good faith with all reasonable efforts to achieve resolution of the matter at issue.

23.2 In this 2006 ITS, "**Dispute**" shall mean the failure of the Parties to reach agreement or concurrence or any matter herein that requires such agreement or concurrence or the failure of the Parties to resolve any disagreement on the application or interpretation of this 2006 ITS, including the alleged failure of either Party to act in good faith with reasonable efforts.

23.3 In the event of a Dispute, either Party may initiate Dispute Resolution by giving written notice to the other Party of the existence of the Dispute, and outlining, in reasonable detail, the nature of the dispute and the facts relied upon by that Part to support its position.

23.4 No later than 7 days following the receipt of such notice, TPTM and CAPP will each appoint a representative or representatives to attempt to resolve the dispute. The representatives appointed by each Party will be individuals who are technically qualified to appreciate and assess the Dispute and who have authority to negotiate a resolution to the Dispute. If the Dispute is not resolved within 30 days of receipt of the notice, the Dispute Resolution will be deemed to have failed.

23.5 Upon the failure of the Dispute Resolution process, either Party may refer the Dispute to the NEB, with the request that the Dispute be resolved by the NEB on an expedited basis.

24. GENERAL PROVISIONS

24.1 If at any time any index, yield or other metric referred to hereunder is not available or ascertainable, the Parties agree to promptly meet to negotiate a mutually satisfactory replacement for such index, yield or other metric.

24.2 TPTM will, at all times, insure its property and potential liability exposures against loss or damage in a manner that is commercially reasonable having regard to the nature of the System.

24.3 This 2006 ITS is subject to the exclusive jurisdiction of the NEB and all matters respecting the determination of Tolls hereunder shall be determined by the NEB, and neither TPTM nor CAPP will bring any action respecting such matters in the Court of Queen's Bench of Alberta or any other superior court.

24.4 This 2006 ITS shall be governed by, construed and interpreted in accordance with the laws of the Province of Alberta and the federal laws of Canada (which for certainty shall include all orders, rulings and guidelines of the NEB) applicable therein.

25. BUSINESS STANDARDS

TPTM and its Affiliates (including Kinder Morgan Canada Inc., the operator of the System) and each of their respective officers, employees and agents are required to abide by the Kinder Morgan Code of Business Conduct and Ethics, which is posted on the Kinder Morgan website at www.kindermorgan.com.

26. CONDITIONS PRECEDENT

26.1 The Parties acknowledge that this 2006 ITS, and tolls determined thereunder, will be subject to the approval of the NEB.

26.2 If either the Pump Station Expansion or the Anchor Loop Expansion is cancelled or postponed as a result of the disapproval of this 2006 ITS by the NEB and not as a result of negligence of TPTM to obtain NEB and other regulatory approvals, the Parties agree that all reasonable and necessary costs incurred by TPTM for the furtherance of either or both Expansions to the date of such disapproval will be recoverable through the Tolls of TPTM, however determined, following the failure or disapproval of this 2006 ITS. The recovery of such costs will be subject to the review and concurrence of CAPP as to the reasonableness of the costs incurred.

27. TERMINATION OF THIS 2006 ITS

27.1 Upon this 2006 ITS being terminated as a result of the expiry of the Term, all amounts owed to or recoverable from Shippers in accordance with this 2006 ITS will be carried forward into a subsequent year's revenue requirement as negotiated with CAPP.

27.2 Upon this 2006 ITS being terminated as a result of a new expansion, all amounts owed to or recoverable from Shippers in accordance with this 2006 ITS will be billed or invoiced to Shippers on a pro-rata basis within 90 days of the termination of this 2006 ITS. Payment terms will be in accordance with the Petroleum Tariff rules and regulations in effect from time to time.

Alliance Taylor Expansion

National Energy Board Office national de l'énergie

Reasons for Decision

Alliance Pipeline Ltd.

GHW-1-2007

September 2007

Facilities and Toll Methodology

Canada

National Energy Board

Reasons for Decision

In the Matter of

Alliance Pipeline Ltd.

Application dated 28 February 2007 for the British Columbia Expansion Project

GHW-1-2007

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Abbreviations

10^3m^3	thousand cubic metres
10^6m^3	million cubic metres
Act or NEB Act	National Energy Board Act
AEUB	Alberta Energy Utilities Board
Alliance	Alliance Pipeline Ltd.
Aux Sable	Aux Sable Canada L.P.
B.C.	British Columbia
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Board or NEB	National Energy Board
BP	BP Canada Energy Company
CAPP	Canadian Association of Petroleum Producers
Chevron	Chevron Canada Resources
CNR	Canadian Natural Resources
Devon	Devon Canada Corporation
EnCana	EnCana Corporation
EPM	Emergency Procedures Manual
EPP	Environmental Protection Plan
FT	firm transportation
ha	hectare(s)
hp	horsepower
km	kilometre(s)
m	metre(s)
m^3/day	cubic metres per day
mm	millimetre(s)
Mcf	thousand cubic feet

MMcf	million cubic feet
MMcf/d	million metric cubic feet per day
MW	megawatts
Nexen	Nexen Marketing
OD	outside diameter
Petro-Canada	Petro-Canada Oil and Gas
Pioneer	Pioneer Natural Resources Canada
PPM	PPM Energy Canada Ltd.
Project	British Columbia Expansion Project
PA	Precedent Agreement(s)
PRPC	Primary Receipt Point Capacity
PRPD	Primary Receipt Point Designation
ROS	Receipt Only Service
Talisman	Talisman Energy Inc.
TAC	Taylor-Aitken Creek
TSA	Transportation Service Agreement
Union	Union Gas Limited
$	Canadian dollars
¢	Canadian cents

Chapter 1

Introduction

1.1 Background and Application

On 28 February 2007, Alliance Pipeline Ltd. (Alliance) filed an application (the Application) with the National Energy Board (NEB or Board) seeking authorization under Parts III and IV of the *National Energy Board Act* (Act) in respect of its British Columbia (B.C.) Expansion project (Project).

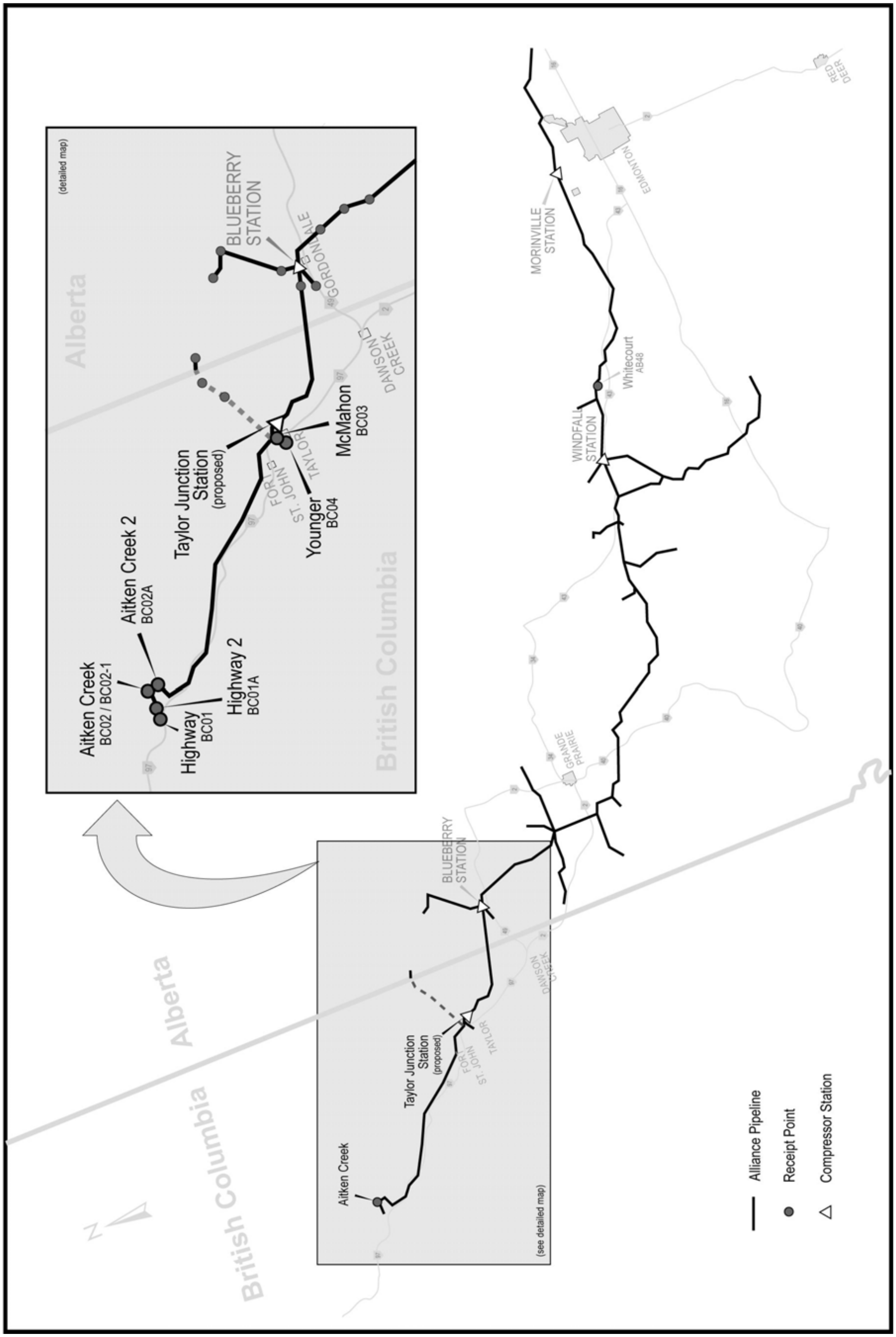
Specifically, Alliance applied for approval under Part III of the Act to construct a new 5.7 megawatts (MW) (7,700 horsepower (hp)) compressor station at its existing Taylor Junction valve and pig trap site. The proposed compressor station site is situated in the southwest corner of SW 10-83-17 W6M where the Aitken Creek and Taylor Laterals join into the Fort St. John Lateral, approximately 20 kilometres (km) southeast of the City of Fort St. John, in northeastern British Columbia. The Project requires 2.2 hectares (ha) of permanent footprint for the proposed compressor site and 1.8 ha of temporary construction workspace for the purpose of alternate site access and for stockpiling and staging equipment and materials. The proposed new compressor station would provide additional receipt capability for the Taylor-Aitken Creek (TAC) zone in northeastern B.C. The planned in-service date for the new station is 1 November 2008. Figure 1-1 is a map identifying the location of the proposed Project and the TAC zone.

Alliance also applied for approval under Part IV of the Act for certain amendments to its Transportation Tariff. These amendments include the introduction of a new Receipt-Only Service (ROS) with respect to the incremental capacity from the TAC zone arising from the installation of the new compressor station.

The expansion would increase firm receipt capacity from the TAC zone by 4.25 million cubic metres per day ($10^6m^3/d$) (150 million cubic feet per day (MMcf/d)) with an additional non-firm capacity of 4.25 thousand cubic metres per day ($10^3/m^3/d$) (20 MMcf/d). The incremental capacity has been fully subscribed and underpinned by long-term contracts. The holders of the contracts have agreed to pay an annual average toll of ten cents per thousand cubic feet (10¢/Mcf ($107.30/$10^3m^3$/month)) for the first five years of the term and 4¢/Mcf ($42.95/$10^3m^3$/month) for the remainder of the contract, ending in 2015.

Alliance also proposed a ROS Secondary Receipt Point Toll to help facilitate the continued high use of the available ROS capacity. Alliance proposed that the revenue generated from the ROS and the ROS Secondary Receipt Point Tolls be treated as a credit to Alliance's total revenue requirement and the associated capital costs be treated as part of its rate base.

Figure 1-1
British Columbia Expansion



1.2 Hearing Process

On 9 March 2007, the Board solicited comments from interested parties as to what process should be followed with respect to considering Alliance's application for the B.C. Expansion. After considering all of the comments, the Board, by letter dated 13 April 2007, established a written procedure that allowed for information requests, evidence and argument.

The Canadian Association of Petroleum Producers (CAPP) submitted written evidence. Letters of Comment were received from the following:

- Aux Sable Canada L.P (Aux Sable)
- Canadian Natural Resources (CNR)
- Chevron Canada Resources (Chevron)
- ConocoPhillips
- Devon Canada Corporation (Devon)
- District of Taylor B.C.
- EnCana Corporation (EnCana)
- Brian and Lori Hill
- Paul, Gordon and Colleen Hill
- Peace River Regional District
- PPM Energy Canada Ltd. (PPM)
- Union Gas Limited (Union)

Written argument was submitted by Alliance, BP Canada Energy Company (BP), CAPP, Nexen Marketing (Nexen), Petro-Canada Oil and Gas (Petro-Canada), Pioneer Natural Resources Canada (Pioneer) and Talisman Energy Inc. (Talisman).

The submissions made by Aux Sable, Chevron and PPM were in support of the application. CAPP opposed the application for reasons which will be discussed in detail. CAPP's position was supported by BP, CNR, ConocoPhillips, Devon, EnCana, Nexen, Petro-Canada, Pioneer and Talisman. Union submitted a letter of comment which stated that the Application presented new details on proposed tariff language that were neither previously discussed with all shippers nor anticipated by Union. With the benefit of the information available as a result of the Board's process, Union acknowledged the need and the benefits of the Taylor Junction Compressor Station and supported the proposed treatment of rolled-in fuel costs, an issue discussed later in this report, as being reasonable. Union suggested that the Board also direct Alliance to refer all future new service proposals to its Shipper Policy Task Force for stakeholder review and discussion prior to filing them with the Board.

Matters raised by letters of comment from the District of Taylor B.C., Brian and Lori Hill, Paul, Gordon and Colleen Hill and Peace River Regional District will be discussed in the Part III section of these Reasons for Decision.

1.3 List of Issues

Based on the submissions from Alliance and the Interested Parties to this application, the Board has organized its Reasons as follows:

1. Need for the Proposed Facilities
2. Consultation, Socio-Economic and Safety Issues
3. Existing Tariff and "Founding Compact"
4. Open Season and Industry Consultation
5. Impact on Existing Services

Chapter 2

Part III Matters

2.1 Need For the Proposed Facilities

Views of the Parties

In its Application, Alliance stated that the installation of the Taylor Junction Compressor Station would relieve the existing receipt capacity bottleneck in northeastern B.C. and enable Alliance to increase its receipt capacity from the TAC zone by 4.25 $10^6 m^3/d$ (150 MMcf/d) to a new total of 12.6 $10^6 m^3/d$ (446 MMcf/d). The purpose of this expansion project is to help Alliance serve the growing demand for access to natural gas transportation capacity out of northeastern B.C. The incremental receipt capacity is underpinned by new long-term contracts with two FT shippers, Chevron and PPM .

Alliance stated that the forecast of gas supply in the source region feeding TAC is robust. According to Alliance, its originally proposed TAC II project, which was the subject of Alliance's open season and which CAPP supported, would rely on the same facilities configuration and the same sufficiency of supply as the applied for ROS. Alliance argued that the applied for project is similar to TAC II in the sense that the facilities are not adding long haul transportation capacity but availing Alliance Firm Transportation shippers (FT Shippers) with increased access to pipeline receipt capacity within the TAC zone.

Alliance stated that while there was insufficient interest under TAC II, there is sufficient interest under the ROS proposal. Both projects would result in expanding the TAC zone receipt capacity. In addition, Alliance stated that ROS does not harm existing shipper classes.

CAPP stated that it does not oppose the TAC II project, as described by Alliance in its open season, which would increase Alliance's capacity to receive gas supplies in the TAC zone. However, according to CAPP, the proposed ROS is neither necessary nor appropriate as the open season did not contemplate that a new service would be necessary to accommodate the expansion and that ROS creates receipt capacity that is not available to other Transportation Service Agreement (TSA) holders in accordance with their negotiated TSAs. Contrary to the availability of unused receipt capacity to other shippers at no additional charge, unutilized ROS capacity would be made available by Alliance to others only if they pay the proposed ROS secondary receipt toll of 15¢/Mcf ($\$5.30/10^3 m^3$).

CAPP stated that the Alliance system is not short of supply and that it has been utilized at or close to capacity since its inception with a contract level of 37 530 $10^3 m^3/d$ (1,325 MMcf/d). According to CAPP, there is a high demand for TAC service which ultimately led to the TAC II Project that was the subject of Alliance's recent open season.

CAPP submitted that it is possible to expand the TAC capacity within the framework of the existing Tariff and that the Alliance Tariff was negotiated as a package and accepted by the NEB as a package. Receipt capacity has been previously added to the system within the framework of the Tariff.

Views of the Board

The Board is of the view that there is a need for additional receipt capacity in the TAC zone. The Board accepts Alliance's evidence that the connected supply and station capacities exceed the proposed design capacity of the system at Taylor Junction and that the proposed facilities will provide shippers with additional flexibility regarding sources and destinations of gas. The Board notes that CAPP supported the TAC II project which would have also increased the receipt capacity in the TAC zone.

The Board further notes that the facilities required to provide for the additional receipt capacity are supported by long-term contracts.

2.2 Consultation, Socio-Economic and Safety Issues

According to Alliance, it initiated a public consultation program with respect to the applied-for facilities by contacting landowners within a 1 500 metre (m) radius of the proposed site. Where owners resided on the property, Alliance staff visited the landowner personally. Where Alliance was not able to contact the landowner or where the landowner did not reside on the property, a project information package was sent by registered mail. Five additional landowners outside the 1 500 m radius were also sent information packages by registered mail. Alliance contacted other stakeholders including local and provincial government representatives and made presentations to them about the Project. Alliance conducted a public Open House in Taylor, B.C.

Letters of comment pertaining to the Part III application were received from the District of Taylor B.C., Brian and Lori Hill, Paul, Gordon and Colleen Hill and Peace River Regional District.

The District of Taylor B.C. had no substantial objection to the Application moving forward but expressed some concerns. It stated that the Application did not provide details related to emergency response and it requested that alternate technology be investigated if flaring is a component of the station's operational methodology.

Brian and Lori Hill stated that they had concerns with respect to the Project's impact on noise levels, quality of life, land values and land use.

Paul, Gordon and Colleen Hill noted their concerns with timely weed control, noise and disturbance from the compressor operation, possible impacts on the value of surrounding land, construction traffic and amendments to an existing landowner agreement.

The Peace River Regional District requested that Alliance address the following issues:

- Complete the current negotiations to mitigate the long term effects of the project on landowners and neighbouring residents
- Use the best technology available to mitigate noise pollution
- Locate the compressor at the greatest distance from the road and/or neighbours as possible
- For aesthetic purposes, use outside cladding of material on the compressor buildings that reflects the agricultural setting
- Provide rural farm tie-in points for access by rural residents affected by the developments in their neighbourhood

With respect to the concerns raised by the District of Taylor B.C., Alliance stated it has an ongoing education and liaison program to promote the awareness of the facilities and how to respond to an emergency on its system. Alliance also responded that there would not be any flaring at the site and that Alliance would be the first responder for any incident at the station. Alliance submitted that natural gas would be vented to the atmosphere under circumstances of emergencies or maintenance blow down. Alliance acknowledged that there is a safety risk in venting natural gas to the atmosphere but submitted that the risk is minimized by upward displacement and dispersion of the plume. Transient modeling conducted by Alliance during the greenfield project determined that the lower flammable limit of a vented gas plume would be closely confined to the blow down valve and would not reach ground level. Alliance further submitted that it has adopted minimum spacing guidelines for the placement of structures at compressor stations to reduce the risk of loss to persons or property to accepted levels. Alliance also provided a description of the emergency shut down and over pressure protection measures to be employed at the proposed facility. Alliance has committed to ongoing consultation with landowners and has stated that it will continue to meet with the Town of Taylor representatives to address any issues.

Alliance submitted that the proposed station is not incongruous with existing land uses in the area (currently a mix of agricultural and industrial uses) and that, given the existing uses; the proposed facilities are unlikely to reduce property values in the vicinity. Alliance indicated there is nothing about these facilities that would interfere with a landowner’s right to build on land adjacent to the applied-for compressor station (at NE ¼ 3-83-17 W6M). Alliance submitted that the colours of the building would blend in with the surroundings and that air quality and noise levels would meet the applicable requirements[1].

The lands required for the proposed compressor station site are situated on a parcel of privately-owned property within the Peace River Regional District. Alliance noted that it has been in discussions with the one directly affected landowner (Paul Hill) to develop a site configuration that will minimize the impact to the landowner's farming operation while meeting Alliance's engineering requirements. No issues specific to the size or configuration of the required land area were raised by Paul Hill or his representatives.

Alliance stated that, in 1997, it acquired from Paul Hill an Above Ground Installation Agreement for a 100 m x 100 m plot of land at the same site for installing a compressor station. However, at that time it only installed a valve site and fenced off a 30 m x 100 m portion of the acquired area. Alliance submitted that it has an agreement-in-principle with Paul Hill to increase this existing 100 m x 100 m area to accommodate the new compressor station site and to provide for the necessary temporary construction workspace. By letter to the Board dated 7 May 2007, Paul Hill, and Gordon and Colleen Hill, stated that this agreement-in-principle was signed on 25 January 2007.

The Hills' 7 May 2007 letter to the Board stated that, as of the date of that letter, the new land agreement negotiations had not been completed to their satisfaction. Alliance stated that it had met with the Hills and their counsel on 11 May 2007 to discuss outstanding issues regarding completion of a land acquisition agreement for Paul Hill's property. These discussions included explaining the legal reasons why Alliance proposes to replace the existing Above Ground Installation Agreement rather than enter into a surface lease agreement, as contemplated by the agreement-in-principle. Alliance also submitted that it has attempted to ensure that the substance of the Hills' concerns is addressed regardless of the specific form of land acquisition agreement.

Views of the Board

Based on the evidence provided by Alliance, the Board is of the view that Alliance has conducted a consultation program commensurate with the nature, setting and potential impacts of the proposed facilities and is satisfied that concerns raised by parties have been addressed. Where there are outstanding concerns the Board expects Alliance to take

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1 Alliance submitted that within British Columbia there are no applicable regulations with respect to environmental noise from compressor stations and so adopted the Alberta Energy and Utilities Board (AEUB) Noise Control Directive ID 99-8 as a project standard. Noise modeling predicted that the continuous sound level contributions from the Station would be in compliance with the nighttime Permissible Sound Level as set out by AEUB Directive ID 99-8 for all residences but one residence located at NE1/4 4-83-17 W6M (200 m southwest of the Station site). Negotiations with the owner of this residence are ongoing with respect to noise abatement or avoidance alternatives (including a possible relocation of the residence) and Alliance confirmed it is committed to developing a mutually acceptable solution.

For project air quality emissions, Alliance conducted its assessment under BC Environment's *Guidelines for Air Quality Dispersion Modelling in British Columbia* and evaluated the project NO_2 emissions to the *Federal National Ambient Air Quality Objectives*.

appropriate courses of action to address these concerns. The Board also finds that Alliance's land requirements and land acquisition approach for the British Columbia Expansion Project are reasonable and appropriate. Furthermore, the Board is of the view that Alliance has demonstrated how it would implement procedural and engineered controls to permit the safe shut down of the facility during an emergency.

As a responsible authority under the *Canadian Environmental Assessment Act*, the Board conducted an environmental screening for the Project. A copy of the Environmental Screening Report is appended to this Decision. The commitments and mitigation that Alliance has made or proposed to address many of the above-referenced concerns are detailed in Section 8.2 of the attached Environmental Screening Report. Further information regarding some of the landowner concerns can be found in the Environmental Screening Report. The Board notes that Alliance must file an Environmental Protection Plan (EPP) with the Board and identify any additional mitigation measures implemented to address any outstanding concerns.

The Board recognises that the venting of natural gas to the atmosphere can pose a safety hazard and notes that in designing the facility, Alliance intends to follow building setbacks for structures to reduce the risk of loss to persons or property to accepted levels. The Board further notes that modelling of the flammable plume was undertaken during the Alliance greenfield project and not specifically for the Taylor Junction Compressor Station. The Board requires Alliance to demonstrate that, for the site specific conditions of the proposed Expansion Project, all site buildings, ignition sources and publicly accessible areas are outside of the flammable plume for the worst case blow down scenario of the proposed facility.

The Board has considered Alliance's application dated 28 February 2007 pursuant to section 58 of the Act, including the commitments and/or mitigation that Alliance has made or proposed, and has issued Order XG-A159-07-2007, the effect of which is to approve the applied-for facilities. The Board grants Alliance exemption from the provisions of subsection 30(1), and sections 31 and 47 of the Act. A copy of the Order is attached.

Alliance is required to file three copies of an update to the Emergency Procedures Manual (EPM) 30 days prior to the operation of the compressor station.

Chapter 3

Part IV Matters

3.1 Existing Tariff and Founding Compact

Views of the Parties

CAPP stated that the proposed ROS service is a fundamental departure from the "founding compact" struck when Alliance was created and as such, it should not be approved. CAPP submitted that the "founding compact" is a business arrangement as well as a Tariff, which includes the TSAs, the Firm Transportation (FT) Service Toll Schedule, the Interruptible Service Toll Schedule, and the General Terms and Conditions. According to CAPP, the "founding compact" was freely negotiated and all shippers were treated equally. It was on the basis of this "compact" that the original Alliance pipeline was supported by 37 shippers and over 40 financial institutions. The original Alliance Tariff was negotiated as a package and approved by the NEB as a package. As such, CAPP requested that the NEB respect the package and deny the application.

Alliance replied that the original Alliance concept was advanced as a new and alternative approach to natural gas pipelining. The interests of shippers, who were also the owners at the time, drove the commercial activities. The motivations behind Alliance's formation do not form part of any business arrangement that continues to bind Alliance. When the current owners acquired their interests in Alliance they acquired an interest subject to the prevailing contractual terms and not a "founding compact". There is no business arrangement beyond the terms of the Tariff, which is a series of contractual arrangements that includes the TSAs, the Toll Schedules, the Toll Principles and the General Terms and Conditions. In summary, Alliance submitted that a document entitled a "founding compact" does not exist.

Alliance further stated that while the Board approved the Tariff as a package, from time to time the Tariff is amended, subject to the Board's approval. The Tariff governs the relationship between Alliance and its shippers. Responsibilities under the Tariff have, at times, been assigned by the original shippers to new shippers. The original 40 financial institutions referred to by CAPP have long been paid out and the current lender group comprises ten banks plus bondholders.

Alliance added that ROS does not erode the rights of FT customers under the Tariff and does not undermine any of the support for negotiated settlements presented to the NEB as a package. According to Alliance, the NEB does not need to deny the Application in order to maintain the Tariff as a package.

Views of the Board

The Board agrees with Alliance that the contractual arrangements with its customers are the TSAs, the Toll Principles, the Toll Schedule and the General Terms and Conditions in its Tariff. While the proposed service is different from what exists now, it is Alliance's right to apply to the Board for changes to its Tariff. The Board is of the view that there is no founding compact beyond the Tariff.

The Board recognizes that certain arrangements were put in place to underpin the original facilities. The Board is of the view that, absent any warranted reason, the approval of the original Tariff should not impose constraints on further expansions of the system.

3.2 Open Season and Industry Consultation

Views of the Parties

Alliance stated that an open season was conducted during October 2006 in response to market interest in Alliance increasing its capacity from the TAC zone. The open season was available only to existing Alliance long-haul FT Shippers. The open season offered existing shippers the opportunity to subscribe for possible expanded receipt capacity on the TAC lateral system. The project for which the open season was conducted is described by CAPP as the TAC II project.

Alliance stated that, after the open season and prior to the filing of the Application with the Board, it consulted with any stakeholders who had expressed an interest in additional receipt capacity in the TAC zone on the precise structure of the new ROS and the framing of the ROS agreement and toll schedule.

CAPP stated that ROS was developed after the open season without NEB authorization. According to CAPP, prior NEB authorization for a new service is the normal prerequisite to offering the new service in a binding open season. CAPP further stated that the NEB looks to such binding commercial commitments in the exercise of its own regulatory jurisdiction and to protect the public interest. The NEB relies on the open season process as part of the consultation it requires of pipelines in the pre-application process.

CAPP stated that the proposed ROS is different from the TAC II project described in Alliance's open season. The TAC II Project was the subject of the binding open season which resulted in Alliance's acceptance of two submissions and execution of Precedent Agreements (PAs) with each of the accepted shippers. CAPP stated that it did not oppose the TAC II Project but opposed the Application as filed.

CAPP further submitted that the Application was unsupported by any properly conducted open season or proper pre-hearing consultation. CAPP noted that the open season and the executed PAs were for the TAC II Project, not the applied-for ROS and, therefore, they could not provide support for the Application. CAPP alleged that Alliance engaged in impermissible side negotiations before the open season closed to induce two 'winning bids', which violated basic commercial law requirements applicable to open seasons. CAPP pointed to what it alleged to be various contradictory statements made by Alliance, which, according to CAPP, demonstrated that Alliance only revealed the ROS concept to its wider shipper community at a 26 January 2007 meeting and that the details of the new service and justification were provided shortly before the Application was filed with the NEB. Based on what CAPP considered to be an unfair open season process and a lack of pre-application consultation, it submitted that the Board should deny the Application.

Alliance stated that there was insufficient interest (by volume and price) under the terms of the open season offering for Alliance to proceed with an economically viable project and that the negotiations which followed the open season represent the competitive market at work. ROS arose out of a standard series of commercial discussions and the ROS package, in its entirety, was sufficiently attractive to the marketplace that it became subscribed. The TAC II concept presented in the open season, however, was not sufficiently valued to attract threshold subscription levels. Alliance further stated that no one has been prejudiced by the process it followed and that CAPP has not identified any party that has been prejudiced or that wanted service pursuant to the TAC II Project and now will not receive it, or that would have wanted ROS but has not been able to subscribe for it.

With respect to communicating the details of ROS to its shippers, Alliance stated that, before filing, it clarified the proposed ROS to CAPP at a joint meeting on 9 February 2007. At that meeting Alliance explained and discussed ROS in full detail, including the proposed Tariff amendments. On 28 February 2007, Alliance fully disclosed ROS in the Application.

In response to CAPP's statement that negotiations undertaken by Alliance violated basic commercial law requirements applicable to open seasons, Alliance stated that the principles established in the Supreme Court decision cited by CAPP are for procurement tender processes that intend to replace negotiations with competition. Alliance stated that its open season was virtually the reverse of that as its rationale was to discern the level and nature of market interest in receiving (not supplying) new service. Alliance argued that all bidders knew from the terms of the open season that Alliance was looking for threshold levels (price and volume) in order to proceed further. If threshold levels were received, it had the discretion to proceed with the project and perhaps follow up to see what adjustments could be made to bring subscriptions up to a threshold level.

Alliance stated that it was prepared to convene a second open season for ROS in the event the Board is of the view that the Alliance open season process lacked sufficient transparency. However, Alliance stated that it doubted that there would be any further interest in ROS capacity. Alliance proposed to offer other FT shippers ROS capacity on the terms contained in this Application, requiring their response within a two week time frame and, only if necessary, returning to the Board for approval of any variations to the facility design resulting from the response. For all subscriptions, Alliance would reserve the right to any, all or none of the following: adjust the total volume, prorate all subscriptions in order to optimize an appropriate compressor unit sizing, negotiate further with bidders as necessary in Alliance's absolute discretion to achieve appropriate modification of terms and anything else that the customers may require.

Views of the Board

The Board has an interest in ensuring that stakeholders are adequately consulted. While Alliance stated that it explained and discussed ROS in full detail at a meeting on 9 February 2007, the Board is of the view that, based on the evidence and comments from intervenors, the communication with respect to the applied-for expansion and the proposed services and tolls was poor. The Board specifically notes Union's comments that had it been consulted about how new service developments would affect its interests prior to Alliance filing a formal application, it is doubtful that Union would have needed to be active in the proceeding.

While open seasons are generally regarded by the Board as evidence of the efficacy of an applicant's consultation with its shippers and the level of interest in a proposed service, an open season is a commercial process. The Board does not have specific rules or guidelines requiring gas pipeline companies to conduct open seasons prior to applying for facilities; nor does it specifically outline how such companies must conduct open seasons. The Board notes the existing avenues of relief outlined in section 71 of the *Act* for parties who are in need of service on a gas pipeline.

The Board notes that Alliance stated that it was prepared to convene a second open season for ROS and was willing to accept that as a condition of Board approval to place into service the proposed facilities and to commence ROS. The Board also notes CAPP's position that the applied-for service is markedly different from what was subject to an open season (i.e. TAC II Project). The Board is of the view that shippers would likely benefit from knowing the general terms and conditions of access to incremental capacity in advance of any planned expansion and/or new service offerings. This will provide transparency and avoids perception of exercising market power. The Board concludes that in this case, given the inadequacy of the consultation process, a second open season is an appropriate course of action. The Board therefore directs Alliance to conduct a second open season.

In an effort to prevent the reoccurrence of such communication problems, the Board encourages Alliance to refer all future new service and/or capacity addition proposals to its Shipper Policy Task Force for stakeholder review and discussion prior to filing them with the Board.

3.3 Appropriateness of the Proposed Services Including Tolling Methodology

3.3.1 ROS Service

Alliance provided a description of ROS in comparison to FT Service. ROS is a service that provides receipt service only; no transportation is involved. ROS was designed to meet the demand for incremental receipt capacity in the TAC zone and to recover the required incremental capital cost involved to provide such service. The intent is to allow the ROS Shippers to deliver an additional 150 MMcf/d (4.25 10^6m^3/d) of natural gas onto Alliance in the TAC lateral system from which they will need to contract with an existing Alliance FT Shipper or use their own FT contracts.

ROS is available to any shipper that is a party to a TSA with Alliance and that has subscribed for ROS. Availability of a subscribed-for volume of ROS is subject to system limitations as determined by point location analysis. ROS, at a receipt point designated by a shipper as a Primary Receipt Point, will receive the same scheduling priority as receipts for FT TAC service. ROS shippers are only permitted to transfer Primary Receipt Point Designations to other receipt points within the TAC zone, provided there is capacity available at the alternate receipt points.

3.3.2 ROS Toll

Views of the Parties

Alliance proposed a toll of 10¢/Mcf ($107.30/$10^3m^3$/month) for the first five years of the service and a toll of 4¢/Mcf ($42.95/$10^3m^3$/month) thereafter until the Primary Term of the ROS Agreements ends in 2015. The tolls were determined based on Alliance’s forecast long-term owning and operating costs of the proposed facilities and an estimated capital cost of $30.3 million. The toll design principles used were the same as those used to generate Alliance’s existing tolls except that capital cost recovery has been accelerated for the first five years. The revenue generated from ROS shippers would be treated as a credit to Alliance’s total revenue requirement and the associated capital costs would form part of the Alliance rate base. As a result, by the end of the first five years of service, the net book cost of the proposed facilities will approximate, proportionately, the amount of undepreciated capital costs from the original system.

Alliance stated that the impact on existing shippers of the proposed service will be neutral at worst, with ROS revenues being offset against the long-haul cost of service. Alliance stated that ROS is consistent with the original Tariff, under which founding customers paid the capital costs in exchange for access to all available capacity.

CAPP stated that the proposed ROS toll of 10¢/Mcf ($107.30/$10^3m^3$/month) does not conform to the Alliance “founding compact”. However, the 10¢/Mcf ($107.30/$10^3m^3$/month) can be justified as a TAC II surcharge, which would be consistent with the “founding compact”. CAPP further stated that Alliance ignored the impact of incremental compressor fuel in determining incremental costs. CAPP submitted that ROS is not neutral to shippers and neither is the toll.

Views of the Board

The Board is of the view that the proposed toll for ROS is cost based as it was developed based on a forecast of long-term operating costs and an estimated capital cost of $30.3 million. While the toll was negotiated between Alliance and the shippers who subscribed for ROS, the Board notes that the proposed toll of 10¢/Mcf ($107.30/$10^3m^3$/month) is the same as the surcharge for the TAC II project, to which CAPP agreed. The Board finds that the proposed toll is just and reasonable and not unduly discriminatory.

The use of an accelerated depreciation rate ensures that the proposed facilities will be depreciated to the same level as Alliance system assets by the end of 2015. The costs of the Project are discussed further in Section 3.4 of these Reasons for Decision.

The Board approves the proposed toll of 10¢/Mcf ($107.30/$10^3m^3$/month) for the first five years of service and a toll of 4¢/Mcf ($42.95/$10^3m^3$/month) thereafter until 2015. The Board directs that any proceeds from the ROS Toll be credited to the revenue requirement for FT shippers.

3.3.3 Secondary Receipt Service

Alliance also requested approval of a Secondary Receipt Service. Alliance submitted that this Service and the corresponding Secondary Receipt Service Toll are necessary to allow long-term shippers an opportunity to mitigate demand charges during periods of under-utilization by selling unused receipt capacity.

ROS secondary nominations will be nominated specifically for a receipt point and will only be made available to the extent that ROS Shippers are underutilizing their firm receipt capacity. Unlike TAC secondary nominations under the current arrangement, all ROS secondary receipts will be charged the ROS Secondary Receipt Service Toll.

3.3.4 Secondary Receipt Service Toll

Views of the Parties

Alliance requested approval of a Secondary Receipt Service Toll of 15¢/Mcf ($5.30/$10^3m^3$) for all volumes flowing from TAC Receipt Points on Secondary Receipt Point nominations. The proposed ROS Secondary Receipt Service Toll is derived from the 100% load factor ROS demand charge divided by the anticipated 66.67% utilization factor.

In Alliance's submission, the ROS Secondary Receipt Point toll would be a fixed toll pegged against a cost-based ROS toll and structured to reflect both the relative differences in cost contributions to the system and the potential frequency of use so that the toll would be roughly equal to the cost of ROS, if the forecast amount of unutilized capacity is entirely sold as ROS Secondary Receipt Point capacity. The proposed ROS Secondary Receipt Point Toll is also set at a level to incent interested customers to contract in the secondary market. According to Alliance, in the past, the Board has approved tolls at levels designed to incent the market to migrate towards other services.

Alliance submitted that the current zero toll for transportation from secondary receipt points originated as part of a negotiated tariff in order to attract a sufficient amount of contract firm transportation to underpin the original Alliance system. Alliance stated that the commercial feasibility of the proposed BC Expansion facilities is dependent upon the ROS Secondary Receipt Service Toll. The need for the ROS Secondary Receipt Service Toll became apparent during the open season process as eligible shippers made inquiries in advance of the submission deadline. It became clear to Alliance that shippers were not willing to subscribe and pay demand charges for the receipt service that offered no meaningful opportunity to mitigate costs in the event that a shipper was unable to utilize its service for a period of time.

Alliance added that the toll would apply only to ROS capacity that ROS shippers do not utilize. It would not apply to excess capacity beyond the 150 MMcf/d (4.25 $10^6 m^3/d$) that will become available as a consequence of placing the proposed facilities into service. Alliance proposed a toll for this service higher than the 10¢/Mcf ($107.30/$10^3m^3$/month) ROS toll so that ROS shippers can mitigate demand charges by selling unused receipt capacity to a third party. Alliance submitted that without such a toll for this service, those interested in the capacity are much more likely to acquire it free from Alliance than pay anything to ROS shippers. Alliance also stated that the implementation of the toll would minimize the possibility of Alliance competing with its shippers to supply unused receipt capacity. All ROS Secondary Receipt Point revenues would be credited to the revenue requirement for FT shippers.

Alliance stated that CAPP's suggestion for the removal of the Secondary Receipt Service Toll would result in ROS shippers subsidizing FT enhancements and that would be unjust. Alliance stated that it believes the Secondary Receipt Service Toll should be higher than the ROS toll for the reasons provided and that it is amenable to the Board fixing the ROS Secondary Receipt Service Toll at some fixed relationship to the ROS toll. In this way the ROS secondary toll would automatically adjust when ROS drops from 10¢/Mcf ($107.30/$10^3m^3$/month) to 4¢/Mcf ($42.95/10^3m^3/month).

Alliance stated that it is not averse to the Board directing Alliance to track utilization of ROS secondary service and report back, after approximately two years, with a recommendation for adjustment of the 15¢/Mcf toll as a consequence of availability.

CAPP opposed the Secondary Receipt Toll and stated that it is inconsistent with the current tolling methodology on Alliance where any firm shipper not fully utilising its firm receipt or delivery capacity, absent any secondary market resale of the capacity, will relinquish that capacity to the use of other shippers who in turn pay no extra toll for that use. In addition, CAPP stated that the Secondary Service Receipt Toll would grant the ROS shippers the ability to economically withhold capacity off the market.

CAPP stated that the evidence points to a project that is not economic as a primary service as Alliance stated that the commercial feasibility of the proposed BCX facilities is dependent upon the ROS Secondary Receipt Service Toll.

CAPP further stated that it was not aware of any regulatory precedent for a toll design that is based in the shipper's expected utilization of its contract. If the expansion is what the market needs, it does not require a special toll design to make it economic for the shipper. The expansion should be able to proceed on the existing toll design methodology.

CAPP stated that TAC receipts were well below the contract capacity and TAC shippers pay demand charges regardless of use. The existing arrangement has led to an active secondary market for capacity on Alliance without a secondary receipt point toll.

CAPP's position is that, at a minimum, the secondary receipt toll should be removed although CAPP's preference is that the Application be denied.

Views of the Board

The Board notes that the proposed ROS Secondary Receipt Service Toll is a toll for shippers to take delivery of gas in the TAC zone at delivery points other than their Primary Receipt Point Designations. It is a toll to provide an alternate point of receiving gas and is only applicable for the 150 MMcf/d (4.25 $10^6 m^3$/d) capacity associated with ROS service. The Board therefore finds that this is not a toll for a secondary market transaction.

The Board is of the view that shippers have the right to dispose of unused capacity in an effort to mitigate associated demand charges. The Board encourages the establishment of unregulated secondary markets which can provide such an opportunity, as well as price signals as to the appropriateness or adequacy of capacity. The Board notes CAPP's submission that a secondary market already exists. The Board does not believe that fixing a secondary receipt point toll would inhibit such a market.

Absent approving the ROS Secondary Receipt Service Toll, Alliance may not be able to expand the system as proposed since the evidence clearly indicates that shippers were not willing to commit to additional investments without a means of demand charge recovery for the unused capacity. The fact that the Tariff was negotiated in order to attract a sufficient amount of contract firm transportation to underpin the original build of the Alliance pipeline does not mean that the same rules should necessarily apply to expansions.

The Board finds that there was no compelling evidence that shippers would be negatively impacted by a toll for secondary receipt point service. The Board finds the proposed toll to be just and reasonable and approves the ROS Secondary Receipt Service Toll at a level of 1.5 times the ROS toll.

In addition, the Board directs Alliance to report to the Board the Secondary Receipt Point transactions, volumes and revenues at the end of the first two years of the new facilities being placed into service along with any recommendations for adjustments.

3.4 Impact on Existing Services and Shippers

3.4.1 Costs to Shippers

3.4.1.1 Capital and Operating Costs

Views of the Parties

According to Alliance, the estimated cost of the proposed Taylor Junction Compressor Station is approximately $30.3 million. Under the proposed funding arrangement, Alliance's owners would contribute 30% of the project costs through equity contributions, consistent with the prevailing capital structure for the pipeline system. Alliance's floating-rate credit facilities are sufficient to debt finance the remaining 70% of the project cost.

The proposed toll is designed to recover the long-term owning and operating costs of the expansion facilities over their economic life, utilizing the same cost and toll design principles used to generate existing Alliance tolls, except that the capital cost recovery has been accelerated for the first five years of the ROS agreements. Alliance stated that the impact of ROS will be neutral at worst because the incremental revenues will offset the incremental costs.

CAPP stated that the ROS toll is not neutral to other shippers as the ROS toll recovers only 45% of the capital costs by 2015, the end of the ROS contract term, and that the incremental fuel costs are not covered by the ROS toll. CAPP further stated that the ROS toll should recover the full cost of providing service and Alliance should be fully at risk for any unrecovered capital and operating costs after 2015.

There were no parties who expressed concern with respect to the level of Alliance's capital and operating costs associated with the proposed facility.

> ***Views of the Board***
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> With respect to operating costs and the capital costs of the proposed facility, the Board notes that there were no parties who expressed concerns with these costs. While Alliance stated that the shippers would be at risk for the undepreciated capital costs of the facility after 2015, the Board is of the view that it is Alliance who is at risk for these undepreciated costs and it will be the responsibility of Alliance to seek approval of a toll structure at an appropriate time.

3.4.1.2 Fuel Costs

Views of the Parties

Alliance proposed that the cost of incremental fuel required to run the compressor should be included on a rolled-in basis in the fuel required to be supplied by FT shippers because fuel use is an attribute of the long-haul transportation service.

Alliance stated that the change in the fuel ratio is relatively nominal and Alliance indicated that the projected change to the fuel ratio is well within the range of the changes that arise from time to time throughout the year. It was also submitted by Alliance that the minor increase in fuel costs to FT shippers is more than offset by the increased flexibility all FT shippers will have as a result of the additional receipt capacity. Alliance noted that the fuel increase is no different than that which would have occurred under the CAPP supported TAC II concept.

Alliance further stated that while ROS shippers do not contribute to system fuel costs through their ROS contracts, they do contribute through their FT contracts. If fuel is charged for ROS as well as FT Service, some shippers could end up paying twice for the same volume of fuel, once with the ROS and again with the FT Toll.

CAPP stated that cost neutrality would dictate that ROS subscribers should pay for the incremental fuel that is required to run the compressor. As ROS does not add to the long haul capacity of the system, it should not be the responsibility of the current long haul shippers to pay the increased fuel cost. While it is the transportation service that pays the fuel under the existing Tariff, the existing Tariff does not contemplate ROS.

> ***Views of the Board***
>
> The Board agrees with Alliance that compressor fuel is a cost which is appropriately shared by all shippers. The Board notes that the increase in fuel costs resulting from the addition of the Taylor Junction Compressor Station is within the range of the changes in fuel that arise at various times on the system. In addition, Alliance has pointed out that there are some potential offsetting benefits to shippers due to the additional volumes coming into the system such as 20 MMcf/d (425 10^3m^3/d) of additional receipt capacity in TAC approximately 360 days/year and increased opportunities for FT shippers wishing to sell unutilized FT capacity.

3.4.2 Impacts on Existing Service

Views of the Parties

Alliance stated that the purpose of this Project is to help Alliance serve the growing demand for access to natural gas transportation capacity out of northeastern B.C. Alliance submitted that it would increase options available to all its shippers by opening access to significantly more supply that would allow customers to fully utilize their FT capacity. Alliance stated that ROS does not harm existing shipper classes while serving an incremental market need.

CAPP stated that ROS creates receipt capacity that is not available to other TSA holders in accordance with their negotiated TSAs. CAPP submitted that it is possible to expand the TAC capacity within the framework of the existing Tariff. Receipt capacity has been previously added to the system within the framework of the Tariff.

CAPP submitted that ROS would alter the position of non-subscribing shippers by increasing the balance of Primary Receipt Point Designation (PRPD) to firm contractible transportation capacity from 125% to 136%. PRPD refers to the designation by a shipper of Primary Receipt Point Capacity (PRPC) which then creates the firm right to put gas onto the system at the designated point up to the designated volume. PRPD is limited, stated CAPP, to 125% of firm long-haul capacity of 1,325 MMcf/d (37.5 $10^6 m^3/d$), that is, it is limited to a maximum long-haul capability of the pipeline of 1.6 Bcf/d (45.3 $10^6 m^3/d$). Therefore the ratio of PRPD to firm long-haul contract capacity is 125%. CAPP submitted that the Alliance proposal would remove this restriction for ROS Primary Receipt Point Capacity.

Alliance stated that the restriction of 125% of PRPC as a percentage of individual shippers' contracted capacity is a function of firm transportation only. ROS cannot have such a specification as it has no firm transportation associated with it. This control on PRPC is relevant for managing priorities between various FT shippers when the demand to deliver gas to a particular receipt point exceeds the receipt capability. As the capabilities of the ROS receipt points in TAC are being expanded by the addition of the Taylor Junction Compressor Station, there will be no adverse impact on FT shippers. Despite subscribing for ROS, FT restrictions on PRPDs remain at 125% of contract capacity.

Alliance noted that, in any event, 125% is no longer a hard and fast rule since Alliance's Tariff amendment of 2003, which gave shippers the option to allocate all or a portion of their PRPC to other shippers. Twelve shippers now hold more than 125% of their contracted capacity, including one shipper who holds 350% more.

Views of the Board

As previously expressed, the Board is of the view that there is a need for additional receipt capacity in the TAC zone. The Board further notes that the facilities required to provide ROS are supported by long-term contracts.

The Board finds that the 125% balance of PRPD to aggregate firm contractible transportation capacity is not a hard and fast rule since Alliance's Tariff amendment of 2003. Furthermore, the Board accepts Alliance's explanation that the ROS proposal will not change the PRPD restriction of 125% of individual shipper's contracted capacity.

Chapter 4

Disposition

The foregoing constitutes our Reasons for Decision on this matter.

G.A. Habib
Presiding Member

R. R. George
Member

S. A. Leggett
Member

Calgary, Alberta
August, 2007

Appendix I

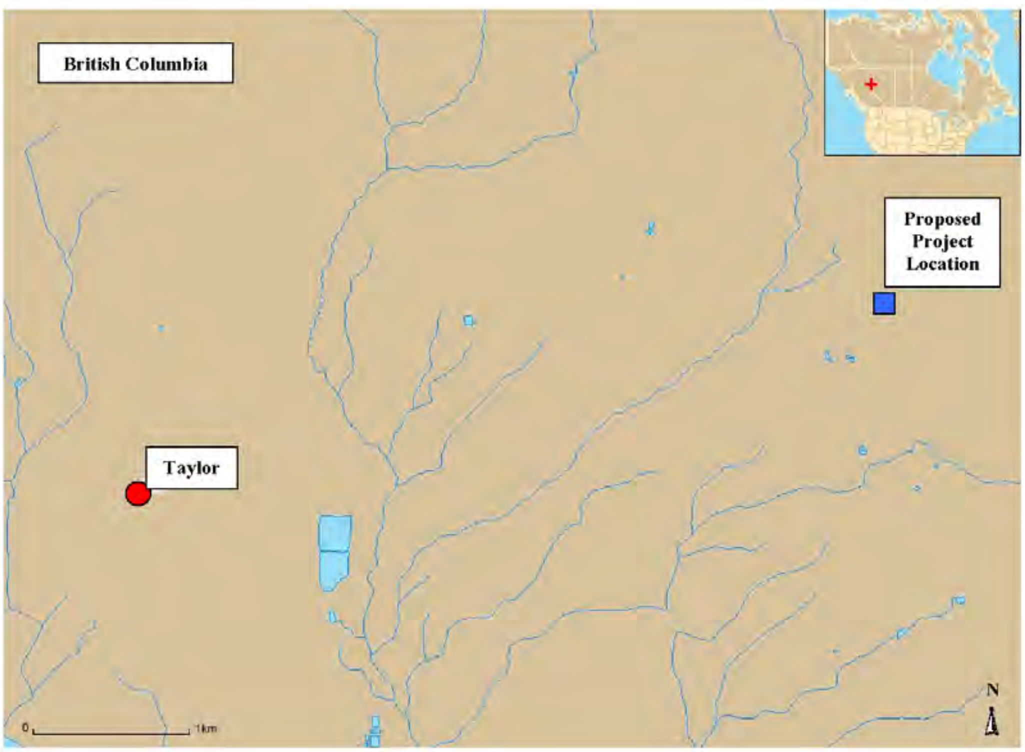
Environmental Screening Report

National Energy Board | Office national de l'énergie

ENVIRONMENTAL SCREENING REPORT
Pursuant to the *Canadian Environmental Assessment Act* (CEA Act)

British Columbia Expansion

Applicant Name:	Alliance Pipeline Ltd. (Alliance)		
Application Date:	28 February 2007	**CEA Act Registration Date:**	30 March 2007
National Energy Board (NEB or Board) File Number:	OF-Fac-Gas-A159-2007-01 01	**Canadian Environmental Assessment Registry Number:**	07-01-27303
CEA Act Law List Trigger:	Subsection 58(1) of the *National Energy Board Act*	**CEA Act Determination Date:**	14 August 2007



Canada

SCREENING SUMMARY

Alliance is proposing to construct and operate a new 7,700 horsepower compressor station at its existing Taylor Junction valve and pig trap site upstream of the British Columbia-Alberta border (the Project). The proposed Project includes the installation of a gas-driven turbine, generator, various buildings, gas cooler facilities and piping. An expansion of the existing site would be required.

Potential adverse environmental effects associated with the Project include effects on soil, vegetation, wildlife, local air quality (including dust levels) and associated health effects, operational noise levels and aesthetics. Potential also exists for contamination of soil/ groundwater and human injury to occur as a result of accidents and malfunctions during construction and/or operation of the Project.

The NEB is of the view that, with the implementation of Alliance's environmental protection procedures, mitigation measures and the NEB's recommendations, the proposed Project is not likely to cause significant adverse environmental effects.

1.0 ENVIRONMENTAL ASSESSMENT PROCESS

The application for the Project was filed pursuant to subsection 58(1) of the *National Energy Board Act* (NEB Act), which triggers the CEA Act *Law List Regulations,* thereby requiring the preparation of this Environmental Screening Report (ESR).

2.0 RATIONALE FOR THE PROJECT

The proposed Project would serve the growing demand for access to natural gas receipt capacity out of northeastern British Columbia (BC).

3.0 BACKGROUND

The Canadian portion of the existing Alliance Pipeline System was constructed in BC and Alberta under authority of NEB Certificate GC-98. GC-98 originally allowed for the construction of the Taylor Booster Station on a 100 m x 100 m plot of land at the exact location where the current Project is proposed. In light of design modifications, that booster station was never built; however, the Taylor Junction valve and pig trap site was constructed at this location within a 100 m x 30 m fenced site.

4.0 DESCRIPTION OF THE PROJECT

Physical Work and/or Activity
Construction Phase – Timeframe: Scheduled to begin in November 2007
▪ Construction of a new compressor station (the Station) at Alliance's existing Taylor Junction valve and pig trap site upstream of the BC-Alberta border at SW ¼ -10-83-17-W6M. Work would include the installation of: ○ a 7,700 horsepower gas-driven turbine, generator and compressor in a common building (approximately 15.9 m x 24.2 m x 10 m) ○ a control/auxiliary building (approximately 13 m x 30 m x 5.5 m) to house electrical and control equipment ○ a fuel gas building (approximately 7 m x 3.2 m x 5.5 m) ○ gas cooler facilities ○ piping to connect the Station to the existing upstream Aitken Creek and Taylor Laterals and downstream to the existing St. John Lateral ▪ The existing site would be expanded to approximately 150 m x 150 m (2.25 ha) and approximately 1.8 ha of additional temporary work space would also be required ▪ Clearing of trees (outside the migratory bird timing period) in the southern and western portions of the Station site ▪ A minimum of 1.9 ha of soil would be stripped from the newly fenced area ▪ The Station site would be accessed from the west via an existing road
Operation Phase – Timeframe: Service life of the Project (estimated in-service date: November2008)
▪ Occasional venting of natural gas during blowdown events (periodic maintenance); no flaring would occur ▪ An increase in operational noise levels is expected
Abandonment Phase – Timeframe: At the end of the service life of the Project
▪ Pursuant to the NEB Act, an application would be required to abandon the facility, at which time the environmental effects would be assessed by the NEB

5.0 DESCRIPTION OF THE ENVIRONMENT

- The Project is located 6 km northeast of Taylor, BC, within the Peace River Regional District (PRRD), but outside of the Peace River valley
- Much of the proposed Station site is currently disturbed, fenced and used as an industrial site
- The Station site expansion would be built on cultivated land, which is owned by Paul, Gordon and Colleen Hill (the Hills)
- Within 1.5 km of the Project, there are 16 quarter sections of land owned by 13 parties; the nearest residents, Ron and Sandra Harden (the Hardens), are 200 m southwest of the Project
- The yellow rail (listed on Schedule 1 of the *Species at Risk Act* as being of Special Concern) has potential to occur in the Project area; however, the BC Conservation Data Centre indicated that this species has not been observed in the Project area, nor does the Project site represent the preferred habitat for this species
- Previously-conducted archaeological surveys extended beyond the boundaries of the existing site into the areas to be disturbed by the Project and no artifacts were discovered, nor were any encountered during initial construction; a recent site assessment confirmed an extremely low potential for heritage resource issues at the Station location; no heritage resources have been identified in provincial records for land within 500 m of the Project
- There are no trapper, guide outfitters or First Nations lands or interest in the Project area

6.0 COMMENTS FROM THE PUBLIC WHICH ARE RELEVANT TO THIS CEA ACT ASSESSMENT

6.1 Project-Related Issues Raised in Comments Received by the NEB

The NEB received comments relating to environmental and socio-economic matters of the Project from the District of Taylor (DoT), PRRD, the Hills and Brian and Lori Hill. Issues of concern were related to the topics of emergency response, flaring, noise levels, aesthetics, weed control, dust levels and the Project's effect on farming operations. Alliance addressed all comments through direct reply letters and responses to NEB information requests. See Section 8.2 for further discussion on the above-mentioned topics.

6.2 Project-Related Issues Raised through Consultation Conducted by Alliance

At the January 2007 public open house in Taylor, one member of the public raised concerns with respect to noise levels. Alliance has since contacted this individual and confirmed that no outstanding issues or concerns remain.

PRRD's Board of Directors raised comments and questions to Alliance regarding the size and appearance of buildings, noise levels and its proximity to residences. Alliance addressed PRRD's comments and questions via a face-to-face meeting and a direct reply letter.

Alliance has actively engaged in discussions with the Hills with respect to land agreements and concerns regarding weed and noise control. Similarly, Alliance continues to consult with the

Hardens regarding noise level increases at their residence. See Section 8.2 for further details regarding these topics.

7.0 METHODOLOGY OF THE NEB'S ENVIRONMENTAL ASSESSMENT

Scope of the factors to be considered:

In conducting the environmental screening, the NEB considered the factors set out in paragraphs 16(1)(a) through (d) of the CEA Act. The scope of the environmental assessment includes the life cycle of the Project within the Project area for those environmental elements listed in Section 8.1.

Baseline information and sources:

The analysis for this ESR is based on Alliance's application, subsequent filings (including responses to information requests) and its Environmental Plans (Volume V, Revision 2, November 1998) that were applicable to the Alliance Pipeline Project as a whole, including the contemplated (but never built) Taylor Booster Station (the Environmental Plans). Further, the Board considered letters of comment and submissions from interested and affected third parties. To obtain documents, please search within the "Regulatory Documents" area on the NEB's website (www.neb-one.gc.ca) or contact the Secretary of the NEB at the address specified in Section 10.0 of this ESR.

Methodology of the analysis:

In assessing the environmental effects of the Project, the NEB used an issue-based approach. In its analysis within Section 8.1, the NEB identified interactions expected to occur between the proposed project activities and the surrounding environmental elements. Also included were the consideration of potential accidents and malfunctions that may occur due to the Project and any change to the Project that may be caused by the environment. If there were no expected element/Project interactions then no further examination was deemed necessary. Similarly, no further examination was deemed necessary for interactions that would result in positive or neutral potential effects. In circumstances where the potential effect was unknown, it was categorized as a potential adverse environmental effect.

An analysis was done for all potential adverse environmental effects of the Project and the NEB's views and findings are outlined in Section 8.2. Section 8.3 addresses cumulative effects, Section 8.4 addresses follow-up programs and Section 8.5 lists recommendations for any subsequent regulatory approval of the Project.

8.0 ENVIRONMENTAL EFFECTS ANALYSIS

8.1 Project – Environment Interactions

	Environmental Element	Project Inter-action? Y/N/U	Description of Interaction (How, When, Where)	Type of Potential Effect P/Ntl/Adv	Potential Adverse Environmental Effect
Bio-Physical	Soil and Soil Productivity	Y	▪ Ground disturbance and vehicle traffic at the Station site	Adv	▪ Reduced soil productivity (due to admixing of layers, erosion, compaction, rutting)
	Vegetation	Y	▪ Use of construction equipment on cultivated land ▪ Clearing of trees	Adv	▪ Introduction/spreading of weeds ▪ Loss of vegetation
	Water Quality and Quantity	N			
	Fish and Fish Habitat	N			
	Wetlands	N			
	Wildlife and Wildlife Habitat	Y	▪ Increased noise from construction activities and Station operation ▪ Increased traffic during construction ▪ Clearing of trees	Adv	▪ Sensory disturbance to wildlife ▪ Wildlife mortality ▪ Loss of habitat
	Species at Risk (federal)	N			
	Species of Special Status (provincial, territorial, local)	N			
	Air Quality	Y	▪ Construction equipment emissions ▪ Increased emissions from gas combustion in the new turbine ▪ Venting of natural gas during facility blowdowns	Adv	▪ Decrease in local air quality
Socio-Economic	Human Occupancy/Resource Use	Y	▪ Site expansion into new areas of agricultural land	Adv	▪ Disruption of farming operations
	Heritage Resources	N			
	Current Traditional Land and Resource Use	N			
	Socio and Cultural Well-Being	N			
	Human Health/Aesthetics	Y	▪ Increased operational noise levels ▪ Increased air emissions during construction and operation ▪ New building construction ▪ Increased traffic during construction	Adv	▪ Nuisance noise to neighbours ▪ Health impacts due to air emissions ▪ Decreased aesthetics ▪ Increased dust levels
Other	Accidents/Malfunctions	U	▪ Spills from equipment during construction or infrastructure during operations ▪ Potential for gas leak/explosion/fire at the Station	Adv	▪ Potential for contamination of soil/ groundwater ▪ Potential for human injury and/or damage to neighbouring properties
	Effects of the Environment on the Project	N			

Legend: Y (Yes); N (No); U (Uncertain); P (Positive); Ntl (Neutral); Adv (Adverse)

8.2 Analysis of Potential Adverse Environmental Effects

Taking into account the nature of the Project, the physical work involved and the environmental setting, the NEB is of the view that the potential adverse environmental effects of the Project can be resolved using the standard design or routine mitigation measures as committed to by Alliance in its application, subsequent filings and Environmental Plans.

Alliance has committed to implementing a Project specific Environmental Protection Plan (EPP) for the Project which would reference the applicable procedures from its Environmental Plans. The Environmental Plans cover all aspects of construction and effects mitigation including, but not limited to, clearing, soils handling, cleanup and reclamation. The Environmental Plans also include various contingency and management plans which address, among other things, spills and increased vehicle traffic.

The following table provides further discussion on various potential adverse environmental effects of the Project for which related public comments have been received by the NEB or by Alliance through its consultation efforts (see Section 6.0 for details on comments received).

Potential Adverse Environmental Effect	Related Topic Raised by:	Commitments and/or Mitigation
Introduction/spreading of weeds	the Hills	▪ The Environmental Plans contain weed control measures, those of which are applicable to the Project would be included in the site-specific EPP ▪ In consultation with the Hills, Alliance has incorporated language into the land agreement to address, among other things, the landowners' concerns regarding timeliness of weed control
▪ Decrease in local air quality ▪ Health impacts due to air emissions	DoT	▪ Alliance confirmed that no flaring facilities are proposed as part of the Project ▪ Potential effects of gas combustion in the new turbine on ambient air quality were evaluated using dispersion models; the results predicted that the maximum 1-hour, 24-hour and annual average ground-level nitrogen dioxide concentrations associated with the Station would fall well below the Federal National Ambient Air Quality Objectives ▪ Alliance submits that venting natural gas from the facility would be an unusual event involving relatively low volumes (dispersed upwards) during periodic maintenance; there is no applicable provincial or federal ambient air quality objective for methane or other constituents of the Alliance natural gas stream to compare venting releases to; however, volumes of released gas would be captured in Alliance's reporting to the National Pollutant Release Inventory, administered by Environment Canada ▪ Alliance has contacted the BC Ministry of Environment regarding provincial permitting requirements with respect to air emissions; no existing concerns have been identified in respect of air quality through this consultation
Disruption of farming operations	the Hills	▪ The location of the Station and associated facilities is dictated by the existing site and safety guidelines; however, consultation with the Hills has resulted in a Station site configuration that minimizes the footprint and impacts to farming operations

Potential Adverse Environmental Effect	Related Topic Raised by:	Commitments and/or Mitigation
Nuisance noise to neighbours	▪ PRRD ▪ the Hills ▪ Brian and Lori Hill ▪ the Hardens	▪ Noise modeling predicted that the continuous sound level contributions from the Station would be in compliance with the nighttime Permissible Sound Level as set out by the Alberta Energy and Utilities Board's Noise Control Directive ID 99-8 (EUB Directive) for all residences but the Hardens' residence (200 m southwest of the Station site) ▪ Negotiations with the Hardens are ongoing with respect to noise abatement or avoidance alternatives (including a possible relocation of the residence) and Alliance indicates that they are committed to developing a mutually acceptable solution ▪ In consultation with the Hills, Alliance has incorporated language into the drafted agreement between Alliance and the Hills to address, among other things, the landowners' concerns regarding noise control
Decreased aesthetics	PRRD	▪ Alliance would use its typical design and colour scheme for the proposed Station, which were selected to blend in with the surroundings in a variety of seasons
Increased dust levels	the Hills	▪ The Environmental Plans contain dust control measures, those of which are applicable to the Project would be included in the site-specific EPP
Potential for human injury and/or damage to neighbouring properties	DoT	▪ Alliance would update its Emergency Response Plan and Continuing Education and Liaison Program to include the Project, prior to placing it into operation ▪ Alliance conducts First Responder Awareness Training with all first responder groups which provides details about local area emergency response plans and procedures, including information on the coordination of company response efforts with local first responders

Significant discussions have occurred, and may continue to occur, between Alliance and affected local parties and landowners regarding various topics of interest. The NEB is of the view that, should the Project be approved, a condition be included in the Order which would require Alliance to submit its Project-specific EPP to the Board, prior to commencing construction. The EPP should incorporate any additional mitigation and commitments made since the filing of the Project application, including those made in consultation with local government agencies and affected landowners. A specific recommendation is included in Section 8.5.

The NEB is of the view that, if Alliance follows through with its commitments and adheres to the NEB's recommendations as set out in Section 8.5, the potential adverse environmental effects of the Project are not likely to be significant.

8.3 Cumulative Effects Assessment

The NEB has considered the potential for cumulative environmental effects and determined that any potential cumulative environmental effects that are likely to result from this Project in combination with other projects or activities that have been or will be carried out would be localized and minor in nature. Therefore, it is unlikely that there would be any significant cumulative environmental effects resulting from this Project.

8.4 Follow-Up Program

The Project and its associated activities are routine in nature. The potential adverse environmental effects of the Project are well understood based on past projects of a similar nature. For these reasons, the NEB is of the view that a follow-up program would not be appropriate for this Project.

8.5 Recommendations

It is recommended that, in any Order that the NEB may grant, a condition be included requiring the applicant to carry out all of the environmental protection and mitigation measures outlined in its application and related submissions.

Further, it is recommended that the following condition be included in any Order granted:

> *Alliance shall file with the Board, at least 30 days prior to construction, a project specific Environmental Protection Plan (EPP), which Alliance shall implement. The project specific EPP shall describe all environmental protection procedures, and mitigation and monitoring commitments, as set out in Alliance's application or as otherwise agreed to during questioning, in its related submissions or through consultation with local government agencies and affected landowners.*

9.0 THE NEB'S CONCLUSION

The NEB is of the view that, with the implementation of Alliance's environmental protection procedures and mitigation measures and the NEB's recommendations, the proposed Project is not likely to cause significant adverse environmental effects.

This represents a determination pursuant to paragraph 20(1)(a) of the CEA Act. This ESR was approved by the NEB on the date specified on the cover page of this report under the heading CEA Act Determination Date.

10.0 NEB CONTACT

Secretary
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta T2P 0X8
Phone: 1-800-899-1265
Facsimile: 1-877-288-8803
secretary@neb-one.gc.ca

Appendix II

Order XG-A159-07-2007

ORDER XG-A159-07-2007

IN THE MATTER OF the *National Energy Board Act* (Act) and the regulations made thereunder; and

IN THE MATTER OF an application dated 28 February 2007, made pursuant to section 58 of the Act, by Alliance Pipeline Ltd. (Alliance), for the construction and operation of the Taylor Junction Compressor Station filed with the National Energy Board under File OF-Fac-Gas-A159-2007-01 01

BEFORE the Board on 14 August 2007.

WHEREAS the Board received an application from Alliance on 28 February 2007 to construct and operate facilities collectively referred to as the Taylor Junction Compressor Station (the Project) at an estimated cost of $30,284,000;

AND WHEREAS information about the Project is set out in the attached Schedule A;

AND WHEREAS, pursuant to the *Canadian Environmental Assessment Act* (CEA Act), the Board has considered the information submitted by Alliance and has performed an environmental screening of the Project;

AND WHEREAS the Board has determined, pursuant to paragraph 20(1)(a) of the CEA Act that, taking into account the implementation of Alliance's proposed mitigation measures and those set out in the attached conditions, the Project is not likely to cause significant adverse environmental effects;

AND WHEREAS the Board has examined the application and considers it to be in the public interest to grant the relief requested;

IT IS ORDERED that, pursuant to section 58 of the Act, the Project is exempt from the requirements of paragraph 30(1)(a), and sections 31 and 47 of the Act, subject to the following conditions:

1. Alliance shall cause the approved Project to be designed, located, constructed, installed, and operated in accordance with the specifications, standards and other information referred to in its application.

2. Alliance shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included in or referred to in its application and related submissions.

3. Alliance shall file with the Board, at least 30 days prior to construction, a Project specific Environmental Protection Plan (EPP), which Alliance shall implement. The Project specific EPP shall describe all environmental protection procedures, and mitigation and monitoring commitments, as set out in Alliance's application or as otherwise agreed to during questioning, in its related submissions or through consultation with local government agencies and affected landowners.

4. Within 30 days of the date that the approved Project is placed in service, Alliance shall file with the Board a confirmation, by an officer of the company, that the approved Project was completed and constructed in compliance with all applicable conditions in this Order. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the Board details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

5. Alliance shall submit to the Board 30 days prior to operating the proposed facility, documentation demonstrating that all site buildings, ignition sources, and publicly accessible areas are outside of the flammable plume for the worst case blow down scenario of the proposed facility. The submission is to include the results of site specific, qualitative analysis for the proposed Taylor Junction Compressor Station stating the method of computation and all assumptions.

6. Unless the Board otherwise directs prior to 30 September 2008, this Order shall expire on 30 September 2008 unless construction in respect of the Project has commenced by that date.

NATIONAL ENERGY BOARD

Claudine Dutil-Berry
Secretary of the Board

Schedule A
ORDER XG-A159-07-2007

Alliance Pipeline Ltd.

Application dated 28 February 2007 for BC Expansion Project
NEB File No.: OF-Fac-Gas-A159-2007-01 01
Project Assessed Pursuant to the *National Energy Board Act*

Facilities Specifications

Construction Type	New
Facility Type	Compressor Station
Location	Taylor Junction (Suction from Aitken Creek Lateral and Taylor Lateral; Discharge to Fort St. John Lateral)
Pump Type	Centrifugal
Pump Power	5.7 MW ISO (7,700 hp) gas driven turbine
Control	Compressor Speed (SCADA)
Associated Facilities	Compressor Building, Fuel Gas System, Building and Generator, Control/Auxiliary Building, Auxiliary Electrical Power, Fire/Gas Detection Systems, Scrubber, Tie-in and Auxiliary Piping
Maximum Allowable Operating Pressure	8,790 kPa