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May 27, 2008

Legislative Budget & Audit Committee
Alaska State Capitol,
Juneau, Alaska
99801-1182

Attention: Representative Ralph Samuels
Chairman

Subject: Alaska Gasline Inducement Act
TransCanada Application for License
Additional Clarifying Information

Dear Representative Samuels:

TransCanada acknowledges receipt of your correspondence dated May 3, 2008 in which TransCanada is asked to provide additional clarifying information to its November 30, 2007 Application for License. In that regard, please find attached our response to the question.

We are submitting this reply to you by two means:

- we are today e-mailing an electronic copy to your attention at Cheryl Sutton [Cheryl_Sutton@legis.state.ak.us] ; and
- we are today forwarding the originally signed document by courier to your office.

I remain available to provide further information or participate in discussions that the State may wish to initiate.

Sincerely,

Anthony (Tony) M. Palmer
Vice President, Alaska Development

1. EXECUTIVE SUMMARY, PAGE 4 FORT NELSON RECEIPT POINT

Legislative Budget & Audit Committee Request

Please describe and explain the mechanics of the toll savings from moving the Alberta receipt point upstream of Boundary Lake to Fort Nelson.

TransCanada Response

The toll savings for Alaska Shippers from moving the Alberta receipt point upstream of Boundary Lake to Fort Nelson (the "Fort Nelson Option") is derived by combining the costs of the pipeline section from Fort Nelson to Boundary Lake with the costs of the Alberta System and recovering the sum of these costs from shippers using these facilities as well as those using the Alberta System.

TransCanada described the mechanics of the Fort Nelson Option and the resultant toll savings to the Alaska Shippers in its response to the third Legislative Budget & Audit Committee ("LB&A") request for additional information and clarification dated February 29, 2008. Please refer to this response for details of the toll savings mechanics.

2. DEVELOPMENT PLAN, PAGE 2.2-65 DEPRECIATION RATE FOR ALASKA SECTION

Legislative Budget & Audit Committee Request

Provide citations and copies of all regulatory precedents for basing the proposed 25-year straight-line depreciation rate for the Alaska Section of the pipeline on length of Transportation Service Agreements (TSAs).

TransCanada Response

In the United States, the depreciation period for recent project-financed, greenfield projects generally is not tied to the length of the contracts. Contract terms for such projects generally are determined based upon shipper competition and other economic conditions, and result in contract terms shorter than 25 years. Tying the depreciation period to the length of such contracts, rather than a longer period such as 25 years, would result in higher rates being charged to shippers over the term of their contracts. Nonetheless, TransCanada believes that it is appropriate to link contract length and depreciation period for the Alaska gas pipeline due to the relative immaturity of the North Slope natural gas producing basin, which creates risk that, at the end of a shorter contract period, additional reserves may not yet be developed and it may not be possible for the pipeline to secure new shipping contracts.

Following are several relatively recent examples in which FERC approved initial pipeline rates based upon a 25-year recovery period.

PROJECT	DEPRECIATION RATE	DECISION
Alliance Pipeline	Alliance Pipeline's recourse rate was based, among other components, on a straight-line 25-year depreciation schedule, resulting in a depreciation rate of 4 percent per year. Alliance's open season resulted in execution of 15-year precedent agreements for over 90% of its design capacity, all of whom elected to take service under negotiated rates. Alliance's negotiated rate structure uses an adjusted depreciation schedule designed to substantially levelize the resulting rates over the 15-year primary term of the transportation agreements. However, it contains a mechanism that allows the pipeline to ensure the recovery of an average of 4 percent per year depreciation from non-renewing shippers over the effective terms of their contracts, by providing for an increased rate over the last 5 years of the primary contract term for any negotiated rate shipper that does not, 5 years prior to the end of the primary contract term, extend its contract.	*Alliance Pipeline L.P.,* 80 FERC ¶ 61,149 (1997) and 84 FERC ¶ 61,239 (1998) (FERC Docket Nos. CP97-168, CP97-169, CP97-177, and CP97-178).
Vector Pipeline	Vector Pipeline's recourse rate was based, among other components, on a straight-line 25-year depreciation schedule, resulting in a depreciation rate of 4 percent per year.	*Vector Pipeline L.P.,* 85 FERC ¶ 61,083 (1998) and 87 FERC ¶ 61,225 (FERC Docket Nos. CP98-131, CP98-133, CP98-134, and CP98-135).

PROJECT	DEPRECIATION RATE	DECISION
Buccaneer Pipeline	The Buccaneer Project's recourse rate was based, among other components, on a straight-line 25-year depreciation schedule, resulting in a depreciation rate of 4 percent per year.	*Buccaneer Gas Pipeline Company, L.L.C.,* 91 FERC ¶ 61,117 (2000) (FERC Docket Nos. CP99-628, CP99-629, and CP99-630).
Kern River	Kern River's rates were based upon a 25-year depreciation life, levelized to provide for rate recovery of plant costs at a rate ranging from a low of 0.6433 percent in the first year to a high of 10.1698 percent in the fifteenth year.	*Kern River Gas Transmission Co.,* 50 FERC ¶ 61,069 (1990) (FERC Docket Nos. CP89-2047, CP89-2048); *Kern River Gas Transmission Co.,* 58 FERC ¶ 61,073, *Order on Rehearing*, 60 FERC ¶ 61,123 (1992) (FERC Docket No. CP89-2048).

In Canada, a number of recent Greenfield pipeline projects have established their depreciation rates over a 25 year depreciation period. The table below presents recent examples of NEB-approved pipelines that established the depreciation rates for their initial investment over a 25 year recovery period.

<table>
<tr><th>PROJECT</th><th colspan="4">DEPRECIATION RATE</th><th>DECISION</th></tr>
<tr><td rowspan="3">Alliance Pipeline</td><td colspan="4">Alliance's depreciation on transportation plant used for purposes of deriving tolls is calculated annually over a 25 year period in accordance with the following rates:</td><td rowspan="3">Depreciation rates for the first 25 years were defined in the Transportation Service Agreements underpinning the Alliance Facilities Application that was approved by the Board in the GH-3-97 Decision.</td></tr>
<tr><td>YEAR</td><td>RATE (%)</td><td>YEAR</td><td>RATE (%)</td></tr>
<tr><td>1
2
3
4
5
6
7
8
9
10
11
12
13</td><td>3.027
3.299
3.571
3.842
4.114
2.686
2.658
2.930
3.202
3.473
3.745
4.017
4.289</td><td>14
15
16
17
18
19
20
21
22
23
24
25</td><td>4.561
4.832
4.575
4.575
4.575
4.575
4.575
4.575
4.575
4.575
4.575
4.575</td></tr>
<tr><td>Maritime & Northeast Pipeline Project (M&NPP)</td><td colspan="4">M&NPP initially had an annual depreciation rate of four percent resulting in a recovery period of 25 years. Through subsequent settlements, M&NPP's depreciation rate has been increased, resulting in a faster recovery period.</td><td>Initial depreciation rate approved by the NEB in the GH-6-96 Decision.</td></tr>
</table>

3. DEVELOPMENT PLAN, PAGE 2.2-65 RATE STRUCTURE FOR ALASKA SECTION

Legislative Budget & Audit Committee Request

a) *TransCanada states that if initial TSAs are for a contract term different from 25-years, the depreciation recovery rate will be adjusted accordingly. Does this mean the rate for a 10-year TSA will be based on a 10-year straight-line depreciation and a 35-year TSA gets a rate based on a 35-year straight-line depreciation?*

b) *Provide citations and copies of all regulatory precedents for basing transportation rates to customers with different contract terms on depreciation rates reflecting the contract terms.*

c) *Please explain the rationale for the proposed variable return on equity that adjusts with the U.S. 10-year Treasury note.*

d) *Provide all citations and copies of all orders which authorize variable equity return for regulated pipelines in the United States and Canada.*

e) *Provide copies of all work papers, studies, reports and internal memos that TransCanada relied upon to arrive at the proposed equity risk premium of 965 basis points over the U.S. 10-year Treasury note.*

f) *What is the current equity risk premium authorized by the NEB for the 2008 Benchmark return on common equity 8.71% for Group 1 pipeline companies?*

g) *What is TransCanada's currently authorized return or equity by the NEB?*

h) *Provide copies of orders authorizing TransCanada's current return on equity. What equity risk premium did the NEB allow to arrive at TransCanada's currently authorized equity return?*

TransCanada Response

a) In Section 2.2.3.4(1) "Proposed Services and General Tariff Terms – Alaska Section and Yukon-BC Section" on page 2.2-61 of TransCanada's AGIA Application, TransCanada has proposed to offer only 25-year, 30-year and 35-year Firm Transportation Services for prospective Shippers to select in the initial Open Season. If a prospective Recourse Rate Shipper selects a 30-year or 35-year Firm Transportation Services, the respective annual depreciation rate would be based on a 30-year or 35-year straight-line depreciation profile.

b) As discussed at Page 2.2-67 of TransCanada's application for license under the AGIA, TransCanada has proposed term-differentiated rates.

   Recently, FERC clarified that its existing negotiated rates and discount policies permit project sponsors, under certain circumstances, to provide rate incentives to shippers on a number of grounds—including, but not limited to, volumes to be transported and length of service commitments—without constituting undue discrimination. *Revisions to Blanket Certificate Regulations and Clarification Regarding Rates*, 71 Fed. Reg. 36276 (2006) (order proposing to amend blanket certificate regulations and clarifying rates) and Order No. 686, 117 FERC ¶ 61, 074 (2006) (final rule) (FERC Docket No. RM06-7).

Following are several recent examples where the FERC has approved the use of rates differentiated on the basis of contract term or volume.

PROJECT	TERM DIFFERENTIATED RATES	DECISION
REX-West	Because of the magnitude of the REX-West project and the consequent need to secure very large capacity commitments, Rockies Express designed its open season to provide incentives for shippers to make large, long-term firm transportation commitments to the project. In this regard, the pipeline established three specific classes of shippers—foundation shippers, anchor shippers, and standard shippers—based upon contracted capacity, offering lower rates and certain other rate-related contractual benefits to those classes of shippers reflecting larger firm transportation commitments (i.e., foundation and anchor shippers). In addition to lower negotiated reservation rates, these incentives included certain most favored nation status benefits, contractual rollover rights, and rights of first refusal.	*Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272 (2006) and 119 FERC ¶ 61,069 (2007) (FERC Docket Nos. CP06-354, CP06-401, and CP06-423).
Gulf Crossing	Because of the magnitude of the Gulf Crossing project and the need to secure very large capacity commitments, Gulf Crossing designed its open season to provide incentives for shippers to make large, long-term firm transportation commitments to the project. In this regard, the pipeline established two classes of shippers—foundation shippers and standard shippers—based upon contracted capacity, offering lower rates and certain other rate-related contractual benefits to foundation shippers, who have made a larger firm transportation commitment.	*Gulf South Pipeline Co., LP*, 123 FERC ¶ 61,100 (2008) (FERC Docket Nos. CP07-398, CP07-399, CP07-400, CP07-401, CP07-402, and CP07-403).

The following table summarizes recent examples where the NEB has approved the use of term-differentiated rates.

<table>
<tr><th>PROJECT</th><th colspan="2">TERM DIFFERENTIATED RATES</th><th>DECISION</th></tr>
<tr><td>Keystone Pipeline Project</td><td colspan="2">Keystone proposed to charge tolls for two types of service: Committed Service which is supported by a long-term Transportation Service Agreement (TSA) and for which Committed Tolls would be charged; and Uncommitted Service which is not supported by a TSA and for which Uncommitted Tolls would be charged.
Committed Tolls were negotiated and designed to recover a combination of fixed and variable costs. The fixed portion of the Committed Toll is designed to be levelized throughout the contract term for the recovery of invested capital. Term differentiated rates are offered for contract terms of 5, 10, 15 and 20 years. Shorter term contracts would be charged a higher fixed component of the toll relative to the longer term contracts. The Uncommitted Toll will be equal to the five year Committed toll (both fixed and variable components) plus a 20 percent premium.
Similar toll structure would be offered for the U.S. section of the Keystone Pipeline except that the Uncommitted Tolls would be calculated by subtracting the Committed Toll revenues from the overall revenue requirement, the result is then divided by the projected uncommitted volumes. Keystone has yet to file the tariff schedule with the FERC but is expected to do so before it enters into commercial operation.</td><td>Approved by the NEB in the OH-1-2007 Decision.</td></tr>
<tr><td rowspan="3">Westcoast Energy Inc. carrying on business as Spectra Energy Transmission</td><td colspan="2">Westcoast proposed to introduce, on a permanent basis commencing 1 January 2006, term differentiated firm service tolls in Zones 3 and 4 to provide shippers with an incentive to contract for firm service over longer terms. Westcoast proposed the following approach to term differentiated tolls:</td><td rowspan="3">Approved by the NEB in the RHW-1-2005 Decision.</td></tr>
<tr><td>CONTRACT TERM (IN YEARS)</td><td>PREMIUM OR DISCOUNT RELATIVE TO THE BASE TOLL</td></tr>
<tr><td>1
2
3
4
5 or more</td><td>+3%
0% (Base Toll)
-3%
-4%
-5%</td></tr>
<tr><td>Express Pipeline Ltd.</td><td colspan="2">Express offered shippers term contracts of 5, 10, and 15 years with corresponding tolls of $1.35, $1.25 and $1.10 U.S. per barrel for shipment of light crude from Hardisty, Alberta to Casper, Wyoming.</td><td>Approved by the NEB in the OH-1-95 Decision.</td></tr>
</table>

c) The Alaska Pipeline Project has a particularly long lead time prior to in-service. Once in-service it is expected to provide services to Alaska and the Lower-48 customers for decades. In order to ensure that Project returns are reflective of the ever changing underlying economic environment, TransCanada has proposed a variable rate of return on equity that is based upon the yield of the U.S. 10-year Treasury Note. TransCanada sought a base instrument that would be transparent, liquid and unaffected by TransCanada or the Alaska Pipeline Project – the U.S. Treasuries meet all these criteria. The U.S. 10-year Treasury Note is very liquid, its yield is determined by the market that reflects the expectations of investors for the future economic environment. The U.S. Treasuries are a widely acceptable benchmark that institutional and individual investors use in assessing the risk-free rate of return that they require when making investment decisions.

TransCanada's proposed variable rate of return on equity approach ensures that Shippers and TransCanada share the upside and downside when there are changes to the U.S. 10-year Treasury Note rate.

d) TransCanada is not aware of any regulated pipelines in the U.S. that have been authorized for a variable equity return.

The approach of establishing variable rates of return on equity based on the equity risk premium concept has been widely used in Canada since the mid-1990s. As part of the Multi-Pipeline Cost of Capital Decision released in 1995 (the "RH-2-94 Decision"), the National Energy Board established a Formula to set the rate of return on common equity for a benchmark pipeline. Attached is the NEB's RH-2-94 Decision along with the letter decision establishing the RH-2-94 ROE for 2008. The RH-2-94 Formula automatically adjusts the approved ROEs for a number of pipelines based on the change to the forecast long term Canadian bond rate. The RH-2-94 Formula is still applied by the NEB to set the approved rate of return on equity of a number of pipelines. Similar approaches are also widely used by Canadian provincial utilities regulators, including the Alberta Utilities Commission, the Ontario Energy Board, the British Columbia Utilities Commission and the Régie de l'énergie du Québec.

In addition, a number of recent NEB-regulated pipeline projects incorporate the RH-2-94 Formula by reference. Examples of such projects include:

PROJECT	ROE AND CAPITAL STRUCTURE	DECISION
Mackenzie Valley Pipeline	The ROE proposed in the October 7, 2004 Application is equal to the rate of return resulting from the RH-2-94 Formula plus 2.21% for the initial 10 years with a deemed capital structure of 70% debt and 30% equity.	Pending – Proceeding is ongoing.
Enbridge's Alberta Clipper	ROE equal to RH-2-94 Formula plus 225 basis points on a 45% equity ratio.	Approved by the NEB in the OH-4-2007 Decision.
Enbridge's Line 4 Extension	ROE equal to RH-2-94 Formula plus 225 basis points on a 45% equity ratio.	Approved by the NEB in the OH-5-2007 Decision.

e) Internal memos, work papers, studies and reports are the proprietary products of TransCanada. TransCanada respectfully declines to provide such documents.

After carefully examining the returns that other greenfield U.S. and Canadian pipelines the FERC and NEB have authorized for in recent years, TransCanada has determined that it is appropriate to seek the requested rate of return on equity for the Project. As discussed in c) above, TransCanada believes the rate of return on equity should be adjusted annually to keep abreast with the changes in the economic environment through a formula approach that uses the U.S. 10-year Treasury Note prevailing rate as the basis. The 965 basis point premium was initially determined by deducting the U.S. 10-year Treasury Note rate of approximately 4.35% as at the beginning of November 2007, when TransCanada was finalizing the AGIA Application, from a notional target 14% rate of return on equity.

Given the size, remoteness, long-lead time for development, and thin equity thickness of the Project, TransCanada believes the proposed rate of return on equity is reasonable and justifiable.

The U.S. 10-year Treasury Note yield changes over time. The current yield is approximately 3.85% in mid-May 2008, which would result in a 13.5% equity rate of return if the Project were in-service now.

Below is the web link to an equity return comparison that Dr. John Neri of Benjamin Schlesinger Associates, consultant to the Legislative Budget & Audit Committee (the "LB&A Committee"), put together at the request of the LB&A Committee. The equity return comparison shows the equity returns for some recent greenfield pipeline projects authorized by the FERC and NEB. It is noteworthy that these pipelines have been approved with a rate of return on equity of approximately 14%.

Web link - http://lba.legis.state.ak.us/proposals/doc_log/2008-04-07_recent_authorized_equity_returns_roe.pdf

f) The NEB has an equity risk premium-based ROE formula and as such does not establish or authorize an explicit equity risk premium. The adjustment mechanism is designed to take into account the year-to-year change in forecast long term (30 year) Government of Canada bond yields. The forecast yield for 30 year Government of Canada bonds for 2008 is 4.55 percent while the resulting benchmark ROE for 2008 is 8.71 percent. The RH-2-94 ROE for 2008 therefore results in an implicit risk premium over the 30 year Government of Canada bond yields of 4.16 percent.

g) TransCanada is the owner or partial owner of the following NEB-regulated pipelines: the TransCanada PipeLines Limited Canadian Mainline ("Mainline"), Foothills Pipe Lines Ltd ("Foothills"), and TransQuébec & Maritimes Pipeline ("TQM" - 50% ownership).

Mainline:

The Mainline is currently subject to a negotiated settlement dated February 23, 2007 that reflects an agreement for a five-year term commencing January 1, 2007 and ending December 31, 2011. The Settlement establishes the components of the Mainline's revenue requirement, including the cost of debt and equity capital, depreciation expense allocated on a segmented basis, and annual Operations, Maintenance and Administrative ("OM&A") expense for each year of the term. The Settlement also establishes the implementation of certain performance-based incentive programs.

The Settlement net revenue requirement in each year of the term incorporates a cost of capital that reflects the rate of return on equity ("ROE") based on the NEB RH-2-

94 formula (8.71% for 2008) and applied to a deemed equity component of 40 percent.

Foothills:

Foothills' current cost of capital reflects an ROE based on the NEB RH-2-94 formula (8.71% for 2008) and applied to a deemed equity ratio of 36 percent.

TQM:

TQM currently has in front of the NEB its 2007 and 2008 Cost of Capital Application in which TQM seeks approval of a fair return on capital resulting from application of a rate of return of 11.0 percent to a deemed equity component of 40 percent of the TQM capital structure.

The NEB has scheduled an oral public hearing to commence in September 2008 to hear TQM's application.

h) See response to f) and g) above.

4. DEVELOPMENT PLAN, PAGE 2.2-65 COST OF DEBT

Legislative Budget & Audit Committee Request

Provide an explanation and supporting documentation which describes how the 4.7% cost of debt was determined.

Provide an explanation and supporting documentation which describes how the 6.2% cost of debt was determined.

TransCanada Response

TransCanada's cost of debt assumptions were based on an expectation that the cost of guaranteed debt will, on average, be approximately 0.5% above the yield on a 10-year Treasury Note and the cost of non-guaranteed debt will, on average be 2.0% above this same benchmark.

The 4.7% and 6.2% interest rates in the Application were based on the above noted spreads and the average observed yield on 10-year Treasuries over a period of six months from June 2007 to November 2007.

The 0.5% spread is based on TransCanada's estimate that the guaranteed debt will have a spread that is approximately equivalent to that of the senior unsecured obligations of large US agencies such as the Federal National Mortgage Association ("Fannie Mae"). Although not explicitly guaranteed, Fannie Mae debt is priced by the marketplace based on an assumption that the federal government will support these obligations. Although Fannie Mae spreads have varied in recent months due to uncertainty with respect to general housing market conditions, TransCanada believes this assumption remains valid and does not believe that the actual spread should vary materially from this estimate.

The 2.0% spread on non-guaranteed debt is based on TransCanada's expectation that the majority of the Project's Shippers will be of investment grade credit quality. The spread is based on TransCanada's general observations of borrowing costs for projects of this nature rather than any specific examples. The actual spread will depend on the credit quality of Shippers on the Pipeline. TransCanada continues to believe this assumption remains valid and reasonable.

5. APPENDIX I1 RECOURSE RATE MODEL OUTPUT – ALASKA SECTION

Legislative Budget & Audit Committee Request

Appendix I1, TransCanada states the results are based upon assumptions "most of which are beyond the control of TransCanada."

State each assumption made to arrive at the "Resources Model Output" presented in Appendix I1. Provide the basis for each assumption and identify each assumption that is beyond the control of TransCanada.

TransCanada Response

The key assumptions for the Recourse Rate Model Output as provided in Appendix I1 were set out in Section 2.2.3.5(1) "Rate Structure and Supporting Information – Alaska Section" on page 2.2-65 of TransCanada's AGIA Application.

The following are the key assumptions that are beyond the control of TransCanada, especially at this early stage of the Project. TransCanada expects as the Project progresses some of these uncertainties will be resolved through the implementation by TransCanada of well-established project management procedures and practices. These procedures and practices are the cornerstones of TransCanada's exemplary record in delivering projects on time and on budget. Discussion of TransCanada's performance history and project capability can be found in Section 2.9 of TransCanada's AGIA Application.

1. Initial Rate Base

   The initial rate base is made up of the Actual Capital Cost, allowance for funds used during construction ("AFUDC"), property tax paid during construction, and initial working capital. The Actual Capital Cost is subject to many external influences that are beyond the control of TransCanada. These external influences include, but are not limited to, prices for materials, equipment, and labor; variation in exchange rates on materials and equipment that will be sourced offshore; the impact of weather on construction progress; availability of equipment and construction labor; and any potential delay in obtaining approvals from regulators and governmental authorities when processing license and permit applications. There are also external factors that could cause the AFUDC and property tax to be beyond the control of TransCanada. These factors are primarily the level of actual interest rates and property tax rates during construction and of course the size of the Actual Capital Cost.

2. Financing Cost

   Cost of financing represents a considerable portion of the annual revenue requirement of the Project. Cost of debt and return on equity are the determinants for the cost of financing. TransCanada does not control the level of interest rates, which determines the cost of debt, nor the U.S. 10-year Treasury Note rate, which will be the basis for the rate of return on equity.

3. Income Taxes and Non-Income Based Taxes

   TransCanada does not have any control on the level of either income taxes or non-income based taxes. TransCanada will pay the amount of income taxes and non-income based taxes to the various levels of government consistent with the prevailing income tax rates as established by the respective governments. Should governments decide to change the tax rates or implement new taxes, those changes will be passed on to the Shippers. The assumptions for income tax rates and property tax rates used in estimating the Recourse Rates for the Alaska Section can be found on page 2.10-2 of TransCanada's AGIA Application.

4. Annual Operating Costs

   The annual operating and maintenance costs are also influenced by a number of factors that are beyond the control of TransCanada. The most significant of these factors is the inflation rate. Other factors include, but are not limited to, a change in exchange rates on materials and equipment that will be sourced offshore, a change in law that causes the operation to become more costly, and a change in insurance premiums.

6. DEVELOPMENT PLAN, PAGE 2.2-66 INCENTIVE ADJUSTMENTS

Legislative Budget & Audit Committee Request

a) *Provide citations and copies of all order issued by the FERC and the NEB for an incentive adjustment to return on equity as presented in Section 2.2.3.6(1).*

b) *Provide citations and copies of all precedents that TransCanada is aware of for an incentive adjustment as presented in Section 2.2.3.6(1).*

c) *What is the basis for the proposed five basis point adjustment for each 1% by which actual capital cost of the pipeline exceeds the base capital cost? In this proposal you propose to give up $1.7555 million in equity return for each $117 million in cost over run.*

d) *Does the proposed annual reset of the return or equity apply to both the Recourse and Negotiated rate proposals?*

TransCanada Response

a) and b)

Incentive adjustments to the rate of return on equity which are the same or similar to the adjustment as presented in Section 2.2.3.6 have been incorporated in a number of recent FERC-regulated and NEB-regulated projects, as summarized in the table below. The table also includes examples of capital incentive mechanisms that adjust the rate base rather than the ROE, which has a similar effect.

PROJECT	INCENTIVE ADJUSTMENT TO ROE	DECISION
Alliance Pipeline	The transportation service package included a capital efficiency incentive intended to encourage Alliance to build the Project in a cost-effective manner. The incentive provided for an increase or reduction in the Alliance's return on equity according to whether actual capital costs are less than or exceed agreed upon baseline estimates. Specifically, the rate of return target was 12 percent on a 30 percent equity ratio if the pipeline's construction cost was as forecasted. It would increase linearly to 14 percent for construction cost savings up to 40 percent of the forecasted level, and decrease linearly to 10 percent for construction cost overruns up to 40 percent of the forecasted level. The actual outcome was an overrun that produced a rate of return on equity of 11.26 percent.	Approved by the *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149 (1997) and 84 FERC ¶ 61,239 (1998) (FERC Docket Nos. CP97-168, CP97-169, CP97-177, and CP97-178). NEB in the GH-3-97 Decision.

PROJECT	INCENTIVE ADJUSTMENT TO ROE	DECISION
Alaska Natural Gas Transportation System	The framework for the original Alaska Natural Gas Transportation System specifically provided for a variable rate of return on equity to provide substantial incentives for the project sponsors to minimize costs and to construct the project without incurring cost overruns. Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System. (Sept. 1997); Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, Sept. 20, 1977, 29 U.S.T. 3581, T.I.A.S. No. 9030. Implementing these authorities, the FERC adopted in Order Nos. 17 and 31 a complicated variable rate of return concept, or incentive rate of return (IROR), for the Alaska portion of the Project and the Eastern Leg of the Prebuild. The variable rate of return mechanism developed by FERC provided for a one-time adjustment to rate base that FERC reasoned would have the same effect as varying the allowed rate of return over the operating life of the pipeline. The adjustment would either increase or decrease the rate base attributable to equity financing, depending on whether or not the project was completed within budget and on schedule.	*Incentive Rate of Return for the Alaska Natural Gas Transportation System*, Order No. 17, 5 FERC ¶ 61,199 (1978), *clarified in* Order No. 17-A, 6 FERC ¶ 61,042 (1979) (FERC Docket No. RM78-12); *Determination of Incentive Rate of Return, Tariff, and Related Issues*, Order No. 31, 7 FERC ¶ 61,237 (1979), *on rehearing*, Order No. 31-B, 8 FERC ¶ 61,250 (1979) (FERC Docket No. RM78-12). *Northern Border Pipeline Co.*, 52 FERC ¶ 61,102 (1990) (FERC Docket Nos. RP89-33 and CP78-124).
Enbridge's Line 4 Extension	The project is subject to a capital cost risk-sharing mechanism under which the rate base may be adjusted in relation to a pre-determined approach that accounts for the difference between the actual and estimated <u>controllable</u> costs of the project. The incentive mechanism is defined in the attached "*Line 4 Extension Settlement.*"	Approved by the NEB in the OH-5-2007 Decision.
Vector Pipeline	The Vector Pipeline rate formula included, among other components, an incentive mechanism to encourage the pipeline company to build the pipeline and place it into service in a cost-effective manner. This mechanism provided for the base return on equity to be subject to adjustment based upon deviations from the estimated capital cost, but only if less than 95% or more than 105% of the estimated capital costs are actually incurred. Under the mechanism, a 0.5% inverse adjustment would be made to the base return on equity for each 10% deviation in actual costs, limited to a total plus or minus of 2%.	*Vector Pipeline L.P.*, 85 FERC ¶ 61,083 (1998) and 87 FERC ¶ 61,225 (FERC Docket Nos. CP98-131, CP98-133, CP98-134, and CP98-135).
Enbridge's Alberta Clipper	The Settlement for the Alberta Clipper project includes three incentive mechanisms to encourage Enbridge to ensure the target in-service date and operation capacity commitment are achieved, while controlling costs. To encourage the control of capital costs, a capital cost risk sharing mechanism would be used. The amount of capital costs booked to rate base would be impacted by the extent to which the actual <u>controllable capital costs</u> are under or over certain threshold values specified in the Settlement. The risk sharing mechanism essentially modifies the base ROE that Enbridge can earn. The details of these incentive mechanisms are defined in the attached "*Alberta Clipper Canada Settlement*."	Approved by the NEB in the OH-4-2007 Decision.

PROJECT	INCENTIVE ADJUSTMENT TO ROE	DECISION
Trans Mountain Pipeline Inc. Pump Station Expansion and Anchor Loop Expansion	These two projects are subject to a capital cost control incentive under which the rate base may be adjusted in relation to a pre-determined approach that accounts for the difference between the actual and estimated controllable costs of the project. The incentive mechanism is defined in the attached *"Incentive Toll Settlement for the Trans Mountain Pipeline System 2006-2010."*	Approved by the NEB through Toll Order TO-06-2006.

c) TransCanada has proposed a reduction in the rate of return on equity ("ROE") of 5 basis points for each 1% by which the Actual Capital Cost exceeds the Base Capital Cost (controllable and non-controllable), up to a maximum of 200 basis points. Although this offer is an exception rather than the norm for new pipeline development, TransCanada's willingness to offer such an incentive adjustment to ROE demonstrates its commitment to manage the construction cost and schedule of the Project prudently.

In order to fully appreciate the appropriateness of this proposal, TransCanada believes the focus should be on comparing the percentage reduction in the ROE premium that TransCanada has proposed in the event of a Capital Cost Overrun versus the percentage increase in the capital cost. In the event of a Capital Cost Overrun that is 40% or more than the budgeted amount, TransCanada is prepared to put approximately 21% (i.e. 200 / 965) of the ROE premium at risk for a period of 5 years. TransCanada believes this is equitable and fair since Shippers have the opportunity to recover toll increases caused by Capital Cost Overrun from market gas price upsides. Commodity price upsides are not a benefit that is available to TransCanada.

d) As discussed in Section 2.2.3.5(1) "Rate Structure and Supporting Information – Alaska Section" on page 2.2-65 and Section 2.2.3.7(1) "Negotiated Rates – Return on Equity" on page 2.2-67 of TransCanada's AGIA Application, the return on equity for both Recourse Rates and Negotiated Rates will be reset annually.

7. DEVELOPMENT PLAN, PAGE 2.2-68 NEGOTIATED RATE CAPITAL STRUCTURE

Legislative Budget & Audit Committee Request

The negotiated rate capital structure described is not clear. Please provide the rationale for each of the stated capital structures and proposed changes to the capital structures as presented in this section.

TransCanada Response

AGIA requires that the initial equity thickness of the Project cannot be more than 30%. TransCanada has proposed to set the capitalization structure of the Project at 70% debt and 30% equity prior to the FERC and Northern Pipeline Agency (the “NP Agency”) approval of the Project’s Actual Capital Cost when the Project has been constructed. Given the competitive nature of the AGIA process, TransCanada decided to change the capitalization structure for the Negotiated Rates by reducing the equity thickness to 25% following the approval of the final Project cost by the FERC and NP Agency in order to reduce Project tolls.

In Section 2.2.3.11(2) “U.S. Loan Guarantee for Capital Cost Overrun” on page 2.2-71 of TransCanada’s AGIA Application, TransCanada has proposed to allocate a portion of the U.S. Loan Guarantee to cover potential Capital Cost Overruns. Under this proposal, Capital Cost Overruns would be financed with 100% debt. Therefore, in the event of a Capital Cost Overrun the overall capitalization structure of the Project would be more heavily weighted with debt.

The capability to finance Capital Cost Overruns with 100% debt would eliminate any incremental investment opportunity for TransCanada as a result of a Capital Cost Overrun. This is another positive attribute of using a portion of the U.S. Loan Guarantee for Capital Cost Overrun credit support.

Since the U.S. Loan Guarantee will not be available for any expansion capital expenditures, TransCanada believes it is prudent to set a capitalization structure for all expansions and maintenance capital with a capital structure that reflects more industry-standard levels, i.e. 60% debt and 40% equity, to ensure financing can be obtained. The benefit of refinancing the initial Project cost with 75% debt also provides headroom for a number of expansions to be financed with 60% debt without causing the overall debt capitalization of the Project to drop below 70%.

8. APPENDIX K1 ANNUAL DEPRECIATION RATES - ALASKA SECTION

Legislative Budget & Audit Committee Request

Provide a narrative explanation and the logic behind the calculation of the Annual Depreciation Rates presented in this appendix.

TransCanada Response

The annual depreciation rates for the Negotiated Rates were established to achieve two goals: recovery of invested capital over the term of the Project Transportation Services Agreements and levelized tolls in nominal dollars. Annual depreciation rates become a variable in order to levelize the tolls. This is an iterative process since the annual revenue requirement is also dependent on the amount of the annual depreciation charges.

This is a classical simultaneous equation analysis that includes the following three boundary conditions:

1. Toll should be sufficient to cover all annual obligations, such as operating and maintenance costs including property taxes, interest expense, return on equity, depreciation and income taxes, for every year over the contract term;
2. The annual revenue requirement for the fixed component of the tolls should be constant in nominal dollars throughout the contract term (in order to produce a levelized toll); and
3. The initial rate base should be fully recovered by the end of the contract term, i.e. the sum of all annual depreciation rates will be equal to 100%.

TransCanada has approached this analysis by performing the following steps:

1. Determine the annual revenue requirement for each year by following the traditional cost-of-service tolling determination methodology and assuming a straight-line depreciation profile;
2. Calculate the present value (“PV”) of the annual revenue requirements as determined in Step 1. Input this PV into an annual payment formula to determine the equivalent annual amount (the “PMT Amount”) that would remain constant throughout the contract term at the same discount rate for the PV calculation;
3. Replace the formula used for determining the annual revenue requirement in the Negotiated Rate model with the PMT Amount as an input. Rerun the model to assess whether the above three boundary conditions are satisfied. If not, adjust the PMT Amount up or down incrementally until the three boundary conditions are satisfied, at which point the PMT Amount is the annual revenue requirement that would provide the appropriate annual depreciation rate profile for the Negotiated Rates.

By following the above steps or by utilizing the Excel problem solver function, both the annual revenue requirement and the annual depreciation rates for the Negotiated Rates can be determined simultaneously.

9. APPENDIX K2 ANNUAL DEPRECIATION RATES - YUKON-BC SECTION

Legislative Budget & Audit Committee Request

Provide a narrative explanation and the logic behind the calculation of the Annual Depreciation Rates presented in this appendix.

TransCanada Response

See response to question 8 of this request for additional information.

10. DEVELOPMENT PLAN, PAGE 2.2-55 OPEN SEASON BIDS PROCESS

Legislative Budget & Audit Committee Request

Provide a simple numerical example of the Open Season bids process described in the first paragraph. Use the possible contract terms and applicable tolls for a constant subscribed volume.

TransCanada Response

In response to this request, TransCanada has assumed the following:

1. Three 1.5 bcf/d capacity bids are received in the Open Season with contract terms of 25 years, 30 years and 35 years each;
2. All three prospective Shippers select the Negotiated Rates option as opposed to Recourse Rates;
3. The Negotiated Rates (excluding fuel) for the Alaska Section and Yukon-BC Section for the 25-year term, 30-year term and 35-year term, respectively, would be \$1.67/mmBtu, \$1.62/mmBtu and \$1.58/mmBtu,
4. Gas heat content at 1,118 Btu/mcf; and
5. A discount rate equal to the after tax weighted average cost of capital of the Project. Based on the assumed financial parameters as set forth on page 2.10-2 of TransCanada's AGIA Application, the discount rate is estimated to be approximately 5.5%.

Outlined below is the present value of each bid based on the above assumptions:

BID TERMS	DAILY VOLUMES	RATES	ANNUAL REVENUE	PRESENT VALUE
25 years	1.5 bcf/d	\$1.67/mmBtu	\$1,022 MM	\$13,712 MM
30 years	1.5 bcf/d	\$1.62/mmBtu	\$992 MM	\$14,412 MM
35 years	1.5 bcf/d	\$1.58/mmBtu	\$967 MM	\$14,885 MM

In this example, based on the present value of each bid, the bid that subscribes for 35-year term will be ranked first, followed by the 30-year term bid and then the 25-year term bid.

Given TransCanada's proposed pipeline design platform is highly flexible to accommodate any volumes within reasonable engineering increments between 3.5 bcf/d and 5.9 bcf/d by adding compression, TransCanada has stated in Section 2.2.3.2(1) "Plan for Open Season – Prudhoe Bay to Boundary Lake" on page 2.2-55 of its AGIA Application that it would first consider accommodating all bid volumes by increasing the initial capacity of the pipeline in the event of over-subscription before implementing capacity allocation by ranking the bids in accordance with their present values as shown in the example above.

11. DEVELOPMENT PLAN, PAGE 2.2-70 SECTION 2.2.3.9 – COMMITMENT TO IN-STATE SERVICE

Legislative Budget & Audit Committee Request

Provide a simplified numerical example of the derivation of a single-zone rate for in-state deliveries using accepted weighted average volumetric-mile cost allocation methods as accepted by the FERC.

TransCanada Response

Please refer to page 4 of 7 of TransCanada's response dated March 20, 2008 to question #3 in the request for additional information from the Legislative Budget & Audit Committee dated February 29, 2008 (C) (third of three documents) for an example.

12. RESPONSE TO STATE OF ALASKA REQUEST FOR INFORMATION DATED JANUARY 29, 2008 REQUEST #14

Legislative Budget & Audit Committee Request

TransCanada addresses gas receipt onto the system in Yukon. *How would TransCanada design the rate for such gas receipts for delivery into the Alberta system?*

TransCanada Response

Consistent with the Northern Pipeline Act (the "NPA") requirement, zonal tolls will be applied for the sections of the pipeline in Yukon and North B.C. There will be two zonal tolls in Yukon and another two in North B.C. These zones are prescribed in Annex II of the NPA and are described in general as below.

Zone 1 – from Alaska/Yukon border to Whitehorse

Zone 2 – from Whitehorse to Watson Lake

Zone 3 – from Watson Lake to Fort Nelson

Zone 4 – from Fort Nelson to the Alberta/B.C. border near Boundary Lake

If a Shipper delivers gas to the Pipeline at a receipt point located in Yukon or North B.C., that Shipper will pay the tolls for each zone through which their gas is transported and the Alberta System receipt toll for delivery to the Alberta Hub. For example, gas received into the pipeline at Whitehorse within Zone 2 will pay a toll equal to the sum of the zonal toll for zones 2, 3 and 4 plus the Alberta System receipt toll to get access to the Alberta Hub.

13. OPERATIONS PLAN, PAGE 2.4-7 SECTION 2.4.1.3 – ROLLED-IN RATES

Legislative Budget & Audit Committee Request

TransCanada states it would propose and support the assignment of expansion costs to all firm billing determinants including negotiated rate contracts. You go on to state you would propose and support rates that bear the same percentage change to all rates including any term-differentiated rates.

a) *Please provide a numerical example and supporting explanation for the derivation of term-differentiated rates starting with a complete cost of service to a 25-year rate and then a detailed calculation and explanation as to how the 30-year and 35-year rates will be set.*

b) *Please provide a numerical example and supporting explanation for the roll-in expansion costs to 25, 30, 35-year rates.*

TransCanada Response

a) The rate setting parameters for the cost-of-service based Negotiated Rates are set forth in Section 2.2.3.7 "Negotiated Rates" on page 2.2-67 to 2.2-69 of TransCanada's AGIA Application. Using the methodology as outlined in the response to question 8 of this request for additional information, TransCanada has estimated the Negotiated Rate (excluding fuel) for Shippers committing to a 25-year Transportation Services Agreement ("TSA") on the Alaska and Yukon-BC Sections would be $1.67/mmBtu in nominal dollars.

   In setting the 30-year and 35-year cost-of-service based Negotiated Rates, the Project rate base was allocated to the three contract terms in proportion to their respective volume commitment. The depreciation periods were extended by 5 and 10 years respectively for the 30-year and 35-year term contracts to reflect the additional term commitment of the Shippers relative to the 25-year case. By following the methodology as outlined in response to question 8 of this request for additional information, the annual revenue requirements and annual depreciation rates for the 30-year and 35-year terms were then determined. TransCanada estimates the levelized Negotiated Rates (excluding fuel) in nominal dollars for the Alaska and Yukon-BC Sections for the 30-year term and 35-year term would be approximately $1.62/mmBtu and $1.58/mmBtu, respectively.

b) In the event of an expansion TransCanada will re-calculate the levelized Negotiated Rates for both the initial and expansion Shippers, subject to the AGIA prescribed 115% rolled-in limitation for the Alaska Section, by following the procedures below.

   Step 1: Calculate the volume weighted average term of all the shipping commitments, taking into consideration the remaining terms and volumes of the existing contracts and the term and volume commitments of the expansion contracts. The resultant average term represents the equivalent length of commitment the pipeline would have from all Shippers if there was only a single contract immediately following the expansion (the "Weighted Average Contract").

Step 2: Revise the opening balance of the rate base to include the incremental capital expenditure and the associated AFUDC for the expansion.

Step 3: Input the revised rate base into the Negotiated Rate model and follow the methodology as discussed in the response to question 8 of this request for additional information to calculate the levelized rate for the Weighted Average Contract.

Step 4: Calculate the total revenue requirement for the Weighted Average Contract over the volume weighted average term.

Step 5: Determine the percentage reduction/increase to all applicable Shippers by equating the sum of all revenues to be collected under each shipping contract over their remaining term to the total revenue requirement as determined in Step 4. Consistent with the principle that Shippers would be treated equally if they contract the same services for the same term, expansion Shippers would be charged the same rate as the initial Shippers which have the same term of commitment.

Step 6: Apply the percentage of reduction/increase to the pre-expansion term differentiated rates to calculate the post-expansion levelized Negotiated Rates for all Shippers, initial and expansion. These new levelized rates would remain effective until the next expansion.

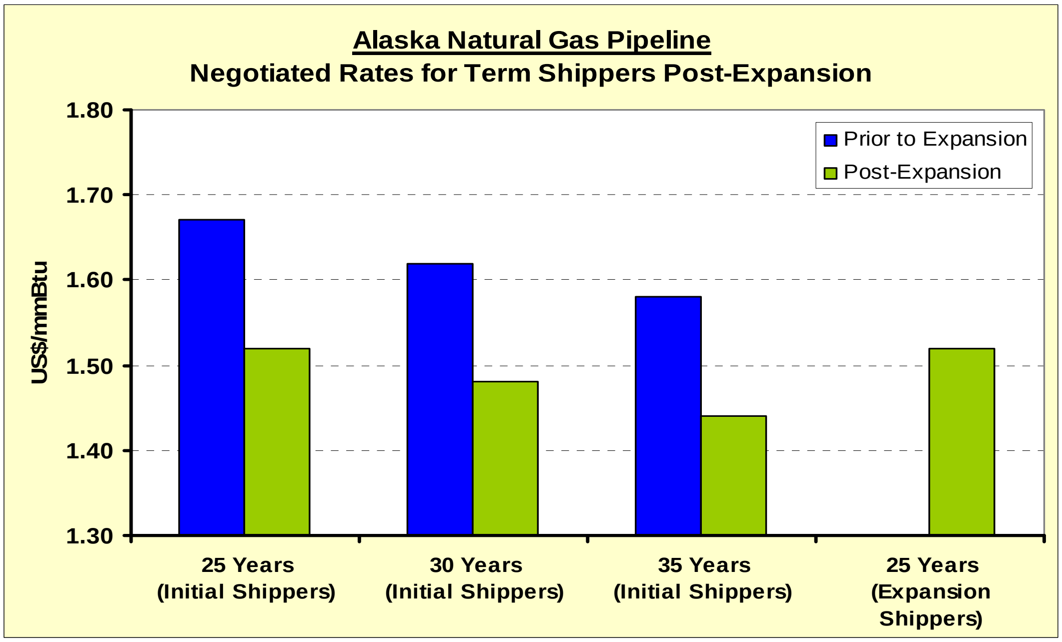
To illustrate the above rolled-in rate calculation for term differentiated tolls in an expansion, TransCanada used the following assumptions for the simplified numerical example.

Assumptions:

i) Three shipping commitments form the initial 4.5 bcf/d base volumes – a 2.0 bcf/d contract for 25 years, a 1.5 bcf/d contract for 30 years and a 1.0 bcf/d contract for 35 years; and

ii) The pipeline is expanded to 5.9 bcf/d by the beginning of year 3 at a cost of $1.6 billion in 2007 dollars (before AFUDC and property taxes). The incremental 1.4 bcf/d shipping capacity has a 25-year contract term.

By following the steps as outlined above, the post-expansion Negotiated Rates for the various term Shippers are derived. The chart below compares the pre-expansion and post-expansion Negotiated Rates for the initial and expansion Shippers in nominal dollars.


Alaska Natural Gas Pipeline
Negotiated Rates for Term Shippers Post-Expansion
US$/mmBtu
1.80
1.70
1.60
1.50
1.40
1.30
Prior to Expansion
Post-Expansion
25 Years (Initial Shippers)
30 Years (Initial Shippers)
35 Years (Initial Shippers)
25 Years (Expansion Shippers)

14. RESPONSE TO STATE OF ALASKA REQUEST FOR INFORMATION DATED JANUARY 15, 2008 ATTACHMENT A, ECONOMIC VIABILITY

Legislative Budget & Audit Committee Request

a) What is TransCanada's understanding of the current and historical basis differential between the Henry Hub and Alberta Hub prices?

b) Please provide all studies, reports, and analyses relied upon to arrive at the US$0.75/mmBtu basis differential between the Henry Hub and Alberta Hub prices. Does the US$0.75/mmBtu basis differential factor in the impact of the addition of 4.5 Bcf/d gas from Alaska on the Alberta Hub price?

TransCanada Response

a) The historical basis differential between the Henry Hub and the Alberta Hub has primarily been a function of the amount of pipeline capacity available to move Alberta gas to markets outside the province relative to the availability of basin supply. In the early years after gas price de-regulation, Alberta gas production capability was greater than the combined capacity on all pipelines to move gas to "out of province" or "export" markets. This resulted in "trapped gas"- gas that was capable of being produced but could not access higher price export markets and could only compete in the intra-Alberta market, driving prices in the Alberta market down compared with sales to other markets outside Alberta. During this period, the Intra-Alberta price as represented by the Alberta Hub price, disconnected from the broader North American market as represented by the Henry Hub price. Basis differentials widened to a maximum of US$1.59/mmBtu on an annual average in 1996.

Natural gas producers recognized the nature and seriousness of the problem and soon contracted with pipeline companies for the construction of enough new export capacity to ensure that pipeline take away capacity would always be greater than gas production capability. By 2000 much of the new take away capacity was in place and basis differentials compressed to just US$0.13/mmBtu in 2001. The basis differential was very low for that year as there were cold weather conditions in Alberta during the winter, resulting in increased residential and commercial heating demand, gas production losses due to well freeze offs and low storage levels. These factors pushed Alberta gas prices higher than Henry Hub prices for several months, a rare occurrence, impacting the annual average.

From 2002 to 2004, a period viewed as representative of the new "over-piped" paradigm, the basis differentials traded in the US$0.60 to US$0.90/mmBtu range on an annual basis, with an average of US$0.70/mmBtu.

Basis differentials widened during 2005 and 2006 due to the 2005 U.S. hurricane season which reduced gas supply from Gulf Coast producing regions, resulting in Henry Hub prices that rose much higher than prices in all other North American gas producing regions. The differential between Henry Hub and Alberta increased to

US$1.57/mmBtu in 2005 but retreated to US$1.25/mmBtu in 2006 as gas supply returned in the Gulf of Mexico.

During 2007 differentials had further compressed to US$0.84/mmBtu, and are expected to remain at similar levels for 2008.

Going forward, TransCanada forecasts that differentials will be comparable to those that were seen in the "new normal" period, during 2002 to 2004 and 2007 where they averaged around US$0.75/mmBtu.

b) At the time that Alaska gas connects into the TransCanada's Alberta System there is expected to be sufficient pipeline take away capacity to move the entire 4.5 bcf/d to export markets. Since all the gas is expected to flow through Alberta to downstream markets there is no forecasted impact on basis.

15. RESPONSE TO LEGISLATIVE BUDGET & AUDIT COMMITTEE REQUEST FOR INFORMATION DATED APRIL 5, 2008 DEPRECIATION RATES

Legislative Budget & Audit Committee Request

In TransCanada's April 22, 2008 reply to request for additional clarification dated April 5, 2008, TransCanada states "Historically, NEB has generally required that gas pipeline rates be cost of service based. However, the pipeline and its customers may agree on the cost of service elements… that are the inputs to establishing the cost-based rate. It is in this context that TransCanada has used the term 'negotiated rate' for the Canadian transportation component."

a) Does TransCanada agree that the depreciation rates presented in Appendix K1, Appendix K2 and the annual depreciation amounts presented in Appendix J1 and Appendix J2 are derived (solved for) values based upon the level Revenue Requirements presented in Appendix J1 and Appendix J2. If not, please describe how you arrived at the depreciation amounts.

b) If the depreciation rates and amounts are derived (solved for) rates and amounts based on the level Revenue Requirements presented in Appendix J1 and Appendix J2, describe how the level Revenue Requirements are determined.

TransCanada Response

a) and b) See response to question 8 of this request for additional information.

16. APPENDIX J1 AND APPENDIX J2 NEGOTIATED RATE MODEL OUTPUT ALASKA SECTION AND YUKON-BC SECTION

Legislative Budget & Audit Committee Request

a) Do the level Revenue Requirements presented in Appendix J1 and J2 represent TransCanada's desired Revenue Requirement with the cost of service items calculated to arrive at that desired level revenue requirement?

b) Provide a detailed, step-by-step, explanation for:

1. *The derivation of level revenue requirement presented in Appendix J1 and J2.*
2. *The derivation* of each cost of service item presented in Appendix J1 and J2.

TransCanada Response

a) and b) See response to question 8 of this request for additional information.