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August 5, 2005

British Columbia Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Robert J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc. ("Terasen Gas)
Application for Approval of SCP IPC Transactions
Response to British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request No. 1, BC Hydro Information Request No. 1, Inland Industrials Information Request No. 1 and Direct Energy Marketing Limited ("Direct Energy") Information Request No. 1

Terasen Gas respectfully submits the attached responses to the above noted Information Requests from the Commission, BC Hydro, Inland Industrials., and Direct Energy.

Twenty hard copies of the attached will be sent to the Commission office by Monday, August 8, 2005.

Yours very truly,

TERASEN GAS INC.

Original signed:

Scott A. Thomson

Attachment

cc. Registered Intervenors

PG&E Energy Trading, Canada Corporation ("PG&E") and Northwest Natural Gas Company ("NW Natural")

1.0 Reference: Exhibit B-1, pp. 5-7; Attachments 1, 2; Exhibit B-2
PG&E Agreements

1.1 On page 5, Terasen Gas Inc. ("Terasen Gas") states that the net effect of the transactions related to the PG&E agreements was expected to increase Terasen Gas' mitigating revenue by $2.5 to $5.2 million per year. Please provide a year-by-year schedule from 2003 to 2020 showing the current estimate of all the revenues and costs from these transactions, including the following:

- *Loss of revenue from PG&E;*
- *Revenue from NW Natural;*
- *Mitigation revenue earned in 2003 and 2004;*
- *Cost of TransCanada PipeLines Ltd. ("TCPL") capacity in 2003 and 2004, and ongoing cost of approximately 6 MMcfd of TCPL capacity commencing in 2005;*
- *Termination payments to PG&E;*
- *Net cost to replace gas supply under the PG&E Peaking Agreement; and*
- *Any other revenue or costs (Please set out the basis for the item and show how the amounts were calculated).*

Please include the total net benefit for each year in then-current dollars and the net present values ("NPV") at two representative discount rates (e.g., nominal rates of 6.02 and 10 percent).

Response:

Please refer to Appendix A.

1.2 Please clarify the reference on Attachment 2 that the termination payments are "to David Pope." Does any affiliate of Terasen Gas receive a benefit from these payments?

Response:

As stated at the workshop the referenced words were inadvertently included on the Attachment. PG&E was purchased by Seminole Energy, a privately held energy company and Seminole Energy assigned the rights to this arrangement to David Pope, President of Seminole. None of the affiliates of Terasen Gas Inc. receive a benefit from these payments.

1.3 Letter No. L-48-02 states that PG&E had an option to convert the termination payment stream to a NPV payment. What was the expected amount of the NPV payment at the time of Terasen Gas' December 5, 2002 application? Can Terasen Gas explain why the option was not exercised? If the option is still in effect, how likely is it that the option will be exercised?

Response:

After Terasen Gas and PG&E had concluded negotiation of the termination payment stream, PG&E sought a further option to monetise the payments. It is likely that PG&E sought this option in order to maintain as much flexibility as possible in light of the financial situation the PG&E group of companies were facing at the time. The value of this option was discussed in Section 3.2 of the 2002 Application.

If PG&E had exercised the option, a lump sum payment would have been made based on the then present value of the termination payment stream using a 15% discount rate. The present value at January 2002 was $2.8 million. Given that Terasen Gas's marginal costs of debt was significantly lower at the time, and continues to be so, if PG&E had elected this option, Terasen Gas's customers would have realised an additional benefit. TGVI does not know why PG&E did not elect to exercise the option; however it is likely that they also recognised that the payment stream was worth more as a series of annual payments than the present value using a 15% discount rate. As long as the costs of debt are lower than 15%, it is unlikely that this option would be exercised in the future.

1.4 Please describe in detail and explain all assumptions regarding the calculation of Terasen Gas' current estimate of the net cost of replacing the gas supply under the PG&E Peaking Agreement, showing both fixed and variable components (It would appear this would be the cost of 46.5 MMcfd of 15 day peaking supply at Huntingdon, plus 6 MMcfd of 15 day peaking supply at AECO, less the variable costs that would have applied for the PG&E peaking supply).

Response:

In order to facilitate communication of the portfolio changes in the midstream portfolio, resources were expressed as separate line items in the Application. When the Midstream evaluates the impact of a resource to the existing portfolio it does so as a whole. It is therefore important to note that costs and benefits outlined below are only part of the total costs and benefits and these costs and benefits can not be evaluated in isolation.

The table of costs and benefits related to the PG&E peaking deal and downstream storage resource is outlined below. The analysis estimates a $1,318K/year benefit (line item 42 in attachment 3a). Terasen Gas applies the probability of a normal, warm and design year occurrence to the net costs for each year to come up with a probability adjusted benefit (cost).

Downstream Storage compared to PGE SCP Peaking deal, 46.5 MMcfd

Line Item		$ ('000's)			**Comments**
1		Normal Year	Warm Year	Design Year	
2	Days used	5	0	15	Number of days the resource is required to meet core load
3	46.5 MMcfd converted to GJd	51.15	51.15	51.15	46.5 mmcfd converted to GJd
4	**Downstream Storage 26 days**				
5	Volume Required for Load TJ	256	0	767	Volume of supply used for Core load
6	Fixed and Variable Charges[1]	($3,779)	($933)	($9,133)	Includes demand charges, summer variable charges and mitigation of excess storage
11	Net Benefit (Cost) of Downstream Storage	($3,779)	($933)	($9,133)	
12					
13	**PGE SCP Peaking**				
14	Average Winter Kingsgate price	$8.54	0	$8.54	Forecasted Winter Kingsgate price
15	Factored price for peak days	2.50	0	2.50	Calculation based on last 5 year winter maximum daily price volatility;(note this is conservative given the contract is based on Kingsgate Common High)
16	Kingsgate daily midpoint	$21.35	0	$21.35	Line ite, 14 times line item 15

[1] Line item No. 6 includes the average Sumas Summer Commodity price for injections of $7.58 US / mmbtu (variable costs), storage demand charges and mitigation activity.

17	Redelivery Diversion Cost	0.55	0	0.55	As per contract the charges for calling the peaking supply
18	Mark-up Cost (15%)	3.20	0	3.20	As per contract 1.5 times Kingsgate Common High
19	Total commodity cost	$25.10	0	$25.10	Assumed $/GJ for PG&E call price
20	Volume Required for Load TJ	256	0	767	Volume of supply used for Core load
21	Net Benefit (Cost) of PGE SCP Peaking Supply	($6,420)	0	($19,260)	
22	Difference between Downstream Storage and PGE SCP Peaking Supply	$2,641	($933)	$10,127	The benefit(cost) difference between scenarios
23	Difference between Downstream Storage and PGE SPC Peaking Supply-Probability Adjusted	$1,254	($443)	$506	Line item 22 times line 24
24		47.5%	47.5%	5.0%	Probability of different load occurrences. The probability is applied to the total cost in the normal, warm and design year.
25	Total Benefit (Cost) Downstream Storage compared to PGE SCP Peaking-Probability Adjusted	$1,318			

The downstream storage option is optimal versus the PG&E peaking arrangement by $1,318/year even though the storage deal has higher fixed costs. The variable costs associated with executing the PGE SCP Peaking deal have a greater overall cost than does the fixed and variable cost associated with the storage option.

By applying the same methodology to the 6 TJ/d of TCPL capacity the result is a $54K/year savings outlined in the table below. However to remain conservative Terasen Gas assumed that the 6 TJ/d would incur a cost of ($186)/year (line item 43 in Attachment 3a). This was based on a $0.245/GJ demand charge and $0.16/GJ mitigation recovery.

AECO/TCPL capacity compared to PGE SCP Peaking Deal, 6 MMcfd

Line		Normal Year	Warm Year	Design Year	Comments
1	Days used	5	0	15	
2	TJ/d	6	6	6	
3	**Alberta**				
4	TCPL Cost	($537)	($537)	($537)	Fixed Costs of TCPL Capacity
5	TCPL Mitigation Recovery	$346	$350	$336	Assumes about 2/3 mitigation recovery as per existing market environment
6	Average Winter AECO price Cdn$/GJ	$8.10	$8.10	$8.10	Forecasted AECO winter price
7	Factored price for peak days	1.5	1.5	1.5	Calculation based on last 5 year maximum winter daily AECO volatility
8	AECO Daily midpoint Cdn$/GJ	$12.15	$12.15	$12.15	Line item 7 times line item 6
9	Volume of Load requirement TJ	30		90	
10	Net Variable Benefit (Cost)	($365)		($1,094)	

11	Net Benefit(Cost) of AECO/TCPL Supply	($555)	($186)	($1,294)	
12					
13	**PGE SCP Peaking**				
14	Average Winter Kingsgate price Cdn$/GJ	$8.54	$0	$8.54	Forecasted Kingsgate Winter Price
15	Factored price for peak days	2.5	0	2.5	Calculation based on last 5 year winter daily volatility (note this is conservative given the contract is based on Kingsgate Common High)
16	Kingsgate daily midpoint Cdn$/GJ	$21.35	0	$21.35	Line item 15 times line item 14
17	Redelivery Diversion Cost	0.55	0	0.55	As per contract charges for calling peaking supply
18	Markup Cost (15%)	3.20	0	3.20	As per contract 1.5 times Kingsgate Common High
19	Total commodity cost	$25.10	0	$25.10	Line item 16+17+18
20	Volume Required for Load TJ	30	0	90	
21	Net Benefit (Cost) of PGE SCP Peaking	($753)	0	($2,259)	
22	Difference AECO/TCPL compared to PGE SCP Peaking	$198	($186)	$965	
23	Difference AECO/TCPL compared to PGE SCP Peaking-Probability Adjusted	$94	($88)	$48	
24		47.5%	47.5%	5.0%	
25	Total Benefit (Cost) AECP/TCPL compared to PGE SCP Peaking-Probability Adjusted	$54			

1.5 *In Exhibit B-2, page 5 of the attached BC Gas Utility Ltd. letter dated December 5, 2002, shows annual demand charges of $7.3 million ($0.45/Mcf) in years 1-6 and $9.0 million ($0.53/Mcf) in years 7-16. Please explain how these demand charges were arrived at. In the explanation, please identify the corresponding SCP, IPC and Westcoast Transportation – south ("T-south") tolls, and discuss any impact such tolls had in establishing the demand charges for NW Natural.*

Response:

The demand charges that were arrived at for the NW Natural transportation service were the result of negotiation between Terasen Gas and NW Natural. Terasen Gas was not privy to NW Natural's evaluation of the capacity, however was aware that NW Natural felt that over the long term, firm transportation service tying Sumas back to Alberta supply basin was an important resource to include in its resource portfolio. Consequently, in response to the IPC open season, NW Natural had made a binding agreement to contract for IPC transportation service based on expected tolls of $0.53 to $0.61 per GJ. The final SCP demand charges negotiated with NW Natural represented a discount to these expected tolls over the medium term and allowed Terasen Gas to commit NW Natural to a long term arrangement even though market conditions were changing. No other payment was made to Terasen Gas or Terasen Inc.

From Terasen Gas's view point, as discussed in the Attachment 3 of the 2002 Application, the demand charges resulted in a significant premium over the demand charges Terasen Gas received from PG&E, even after adjustment for termination payments and other costs. One consideration was the impact the Kingsvale South tolls would have had on the demand charges received from PG&E if the original agreements had stayed in place, and the contracts had been renewed beyond the primary term (i.e. beginning in November 2010). Article 6.1(c) of the original PG&E and BC Hydro SCP transport agreements allows for the demand charges to be adjusted for the renewal period based on the actual Westcoast T-South and Kingsvale South tolls. At the time of the 2002 Application it was estimated that the result would be to increase the annual demand charges from $3.6 million to $4.8 million.

2.0 Reference: Exhibit B-1, pp. 5-7; Attachments 1, 2
Southern Crossing Pipeline ("SCP") Deferral Account

2.1 The Application at page 6 and Attachment 2 describe the SCP Deferral Account. Deferred revenues of $3.6 million in 2003 and $3.0 million in 2004 were recorded in the account, with a corresponding credit to delivery margin revenue. What delivery margin revenue from the PG&E/NW Natural SCP capacity was included in projections of Terasen Gas Revenue Requirements for 2003, 2004 and 2005?

<u>Response</u>:

"Notional" from PG&E and revenue from NW Natural that was included in the revenue requirements margin for rate-setting purposes for the test years 2003, 2004 and 2005 was as follows:

2003	
PG&E	$3.6 million
NW Natural	nil
2004	
PG&E	$3.0 million
NW Natural	$1.2 million
2005	
PG&E	nil
NW Natural	$7.3 million

2.2 Mitigation revenue related to the PG&E SCP capacity was recorded in the SCP Deferral Account. Please explain why the revenue from NW Natural commencing November 2004 was not also recorded in the account. If the Commission has approved this accounting treatment of revenue from the PG&E/NW Natural SCP capacity, please clarify where the approval was set out and provide a copy of the relevant section of the application that was approved.

<u>Response</u>:

The Company submits it is appropriate to include the transportation revenue it receives from NWN commencing November 2004 in its revenue account and not in a deferral account. This treatment is consistent with practise with respect to other SCP firm transportation revenue collected from PG&E and BC Hydro. This treatment has been approved by the Commission, most recently as part of Order No. G-112-04 approving rates for 2005 following the 2004 Annual Review process.

The Company submits that the Commission approved the accounting treatment of revenue for the PG&E SCP capacity for the period January 2003 and through November 1, 2004 in Letter No. L-48-02. Here it stated "Revenue from PG&E under the

Transportation Agreement is margin revenue. BC Gas proposes to record mitigation revenue from the SCP capacity in the existing SCP margin recover account. The Commission determines that, at least until November 1, 2004, variances from the forecast amount of revenue from the PG&E SCP capacity and related mitigation revenue should be recorded in a SCP third party revenue mitigation account. BC Gas is directed to track such losses and revenues as a separate category within the account." As stated in the response to BCUC IR No. 2.1 above, the Company followed this treatment of accounting for the deferred revenues from PG&E (as shown in the table provided in response to IR 2.3) in its forward test years for 2003 and 2004 and included this in its submissions to the Commission for rate-setting purposes, approved in Order No. G-80-03 and No. G-112-04, respectively.

2.3 *Please provide a form of Attachment 2 that includes the NW Natural revenue, the PG&E termination payments and the corresponding deferral of the offsetting loss of PG&E revenue in the account, for the period through 2010.*

<u>Response</u>:

A form of Attachment 2 that includes the NW Natural revenue as mitigating revenue, the tax offset and amortization to the deferred cost is shown below.

Table 3: Attachment 2 (Modified as per BCUC IR1 – No. 2.3)

Particulars	2003	2004	2005	2006	2007	2008	2009	2010
Opening Balance	$ -	$ 888,792	$ 1,807,880	$ (2,934,346)	$ (2,200,359)	$ (1,466,373)	$ (732,386)	$ 1,601
Before Tax								
Deferred Revenues	3,600,000	3,000,000						
SCP Mitigation	(2,200,327)	(514,796)						
NW Natural Revenue		(1,219,516)	(7,297,102)					
PG&EEC Termination Payments		137,500	825,000					
Subtotal	1,399,673	1,403,188	(6,472,102)	-	-	-	-	-
Part I Tax Rate	36.50%	34.50%	34.50%					
Tax Offset for Deferred Revenue / SCP Mitigation	(510,881)	(857,395)	-					
NW Natural Revenue		420,733	2,517,500					
PG&EEC Termination Payments		(47,438)	(284,625)					
After Tax Cost	888,792	919,088	(4,239,227)	-	-	-	-	-
Amortization								
Deferred Revenue / SCP Mitigation			(503,000)	(503,000)	(503,000)	(503,000)	(503,000)	(1,601)
NW Natural Revenue				1,394,596	1,394,596	1,394,596	1,394,596	
PG&EEC Termination Payments				(157,609)	(157,609)	(157,609)	(157,609)	-
Balance, End of Year	$ 888,792	$ 1,807,880	$ (2,934,346)	$ (2,200,359)	$ (1,466,373)	$ (732,386)	$ 1,601	$ 0

Note: For 2004, the NW Natural Revenues will be forecast in the Revenue Requirement

2.4 On page 6, Terasen Gas requests approval to debit the amount of the PG&E termination payments to the SCP Deferral Account, including debits of $137,500 in 2004 and $825,000 in 2005. Please explain why these costs should be debited to the account, if the corresponding revenue from NW Natural is not being credited to the account.

Response:

As stated in the Application on page 6 "Terasen Gas agreed to an annual termination payment schedule to be paid to PG&E commencing November 1, 2004, coincident with the commencement date of the firm transportation service to NWN. The termination payments were to be a debit to the delivery margin revenue resulting in an offset to the NWN transportation revenue. For the purposes of its 2004 and 2005 revenue requirements, the Company intended to include reductions to delivery margin revenue in the amount of $137,500 and $825,000 respectively, for a total of $962,500. However, these transactions were not taken into consideration when the Company presented its annual revenue requirements at the 2003 and 2004 Annual Reviews. As a result of this oversight, the Company debited this amount to the deferral account described above. Commencing in January 1, 2006, Terasen Gas proposes to debit future annual payments to the delivery margin revenue account, and will include this in its forecast of annual revenue requirements, as part of its Annual Review. "

By charging the termination payments to the deferral account it allows Terasen Gas the ability to recover the cost of the termination payments from customers, thereby offsetting the NWN revenue recorded in the November 1, 2004 to December 31, 2005 period.

2.5 Further to the statement at the bottom of page 6 of the Application, please confirm that commencing January 1, 2006 Terasen Gas proposes to credit future revenue from NW Natural and debit future annual termination payments to the delivery margin revenue account and to include these amounts in its forecast of annual revenue requirements.

Response:

Confirmed.

2.6 Please clarify the impact on ratepayers if the Commission does, or does not, approve the recording of the 2004 and 2005 termination payment amounts in the SCP Deferral Account.

Response:

If the termination payments are not approved for inclusion in the deferral account and subsequent amortization, the impact on ratepayers will be through the earnings sharing mechanism as a slightly lower return on equity will be realized for both 2004 and 2005, as these costs will now be expensed, lowering the amount that is to be shared with ratepayers in the following year.

However, the termination payments should have been included in the Forecast so to adjust for the oversight; we recorded these payments in the Deferral Account to be recovered at a future date. The cost recovery was approved (Order Letter L-48-02, which approved the transactions in their entirety.

3.0 Reference: Exhibit B-1, pp. 5-7; Attachments 1, 2
Requested Approvals Related to the PG&E Agreements

3.1 On page 3, the Application seeks approval of the recovery mechanism for the PG&E termination payments. If this means something other than the recording of the 2004 and 2005 termination payments in the SCP Deferral Account and the corresponding amortization amounts shown on Attachment 2, please explain.

<u>Response</u>:

Item 13, at the bottom of page 3, is seeking approval of the recovery of termination payments in the margin as an offset to the NW Natural revenues for 2006 forward to the end of the PG&E termination agreement (October 31, 2019). As well as the recovery of the amount termination payments deferred, net of tax November 2004 through December, 2005. The deferred costs would be recovered through the margin by amortizing the costs from 2006 through 2009.

3.2 The Application also seeks approval of recovery of the SCP Deferral Account related to the Interim Period (January 1, 2003 through October 31, 2004). On page 6, Terasen Gas states that the deferral account balance was approximately $3.9 million at December 31, 2004 and on page 6 notes that Commission Order No. G-112-04 approved the amortization (recovery in rates) of approximately $503,000 of the SCP Deferral Account balance in 2005. Please explain specifically the dollar amount of the SCP Deferral Account balance and the amortization schedule that Terasen Gas seeks approval of.

<u>Response</u>:

Terasen Gas Inc. is seeking approval of the following items in SCP Deferral Account that relate to the PG&E termination payments, which were set out in Attachment 2:

1. The termination payments for the period November, 2004 through December, 2005 ($137,500 + $825,000) less;
2. the tax savings offset ($47,438 + $284,625) to be charged to the deferral account.
3. The net of tax costs to be amortized over four years from 2006 to 2009 at $157,609 per year.

The amortization of the remainder of the balance in the deferral account, as noted in the Information request, was approved in Commission order No. G-112-04.

3.3 The Application also seeks approval to continue to use the 6 MMcfd of residual SCP capacity as part of its Midstream portfolio. Does the request also seek similar approval for the corresponding amount of TCPL capacity? If similar approval is sought, what termination rights does Terasen Gas have with respect to the TCPL capacity? Please confirm that this capacity was included in the Midstream portfolio that Terasen Gas recommended in its 2005/06 Midstream Annual Gas Contracting Plan dated June 2, 2005 ("2005/06 GCP").

Response:

The TCPL capacity was approved by the Commission in L-48-02 and has been part of the 2003/04 and 2004/05 Annual Contracting Plans approved by the Commission. Terasen Gas negotiates the TCPL capacity on a yearly basis. This capacity was included in the portfolio recommended in the 2005/06 Midstream Annual Contracting Plan.

BC Hydro SCP Transportation Service Agreement ("TSA") and Put Option

4.0 Reference: Exhibit B-1, pp. 7-10; Appendix 3a, 3b
BC Hydro SCP TSA and Peaking Agreement

4.1 On page 8, Terasen Gas estimates transactions related to the return of the BC Hydro SCP capacity will have net benefits of $2 to $3 million per year. Please provide a year-by-year schedule from November 2005 to October 2010 showing the current estimate of all revenues and costs from these transactions, including the following:

- *Loss of revenue from BC Hydro/Terasen Inc.;*
- *Net cost to replace the gas supply under the BC Hydro Peaking Agreement;*
- *Net savings in Westcoast toll charges from the release of 54.0 TJ/d of Westcoast T-south long haul capacity;*
- *Net change to total gas costs consistent with the release of the 54.0 TJ/d of T-south; and*
- *Any other revenue or costs (Please set out the basis for the item and show how the amounts were calculated).*

Please include the total net benefits for each year in then-current dollars and the NPV at two representative discount rates.

Response:

Please refer to Appendix A.

4.2 The use by Terasen Gas of the BC Hydro SCP capacity and the turn back of Westcoast T-south was discussed in the 2005/06 GCP. Please file, in this proceeding, copies of Terasen Gas' responses to Commission Information Requests 3.1 and 3.3 through 3.11 regarding the 2005/06 GCP. If Terasen Gas wishes to delete some information such as supporting details that it considers to be commercially sensitive from the responses, it should identify where information has been deleted and discuss that the substance of the response remains intact.

Response:

Please refer to Appendix B. Please note that IR 3.11 regarding the GCP has been modified to provide further clarity.

4.3 The Application at page 9 states that Terasen Gas proposes to replace the terminated BC Hydro Peaking Agreement with a peaking arrangement at Kingsgate, and estimates this will be approximately $280,000 cheaper than the BC Hydro Peaking Agreement. The response to BCUC IR 3.3 for the 2005/06 GCP provides a calculation of the net annual amount as a somewhat different number. Please provide an explanation of each of the assumptions and factors used in the calculation in the response to BCUC IR 3.3.

Response:

The BCUC IR 3.3 assumed a different Kingsgate winter price and a different exchange rate than SCP/IPC submission given the analysis was done at different dates. In order to facilitate communication of the portfolio changes in the midstream portfolio, resources were expressed as separate line items in the Application. When the Midstream evaluates the impact of a resource to the existing portfolio it does so as a whole. It is therefore important to note that costs and benefits outlined below are only part of the total costs and benefits and can not be evaluated in isolation. Line items 43 to 46 in Attachment 3b are must be evaluated as a portfolio.

The table below illustrates for simplicity purposes the typical utilization of the resources on peak and non peak days.

Typical Utilization of Resources on Peak and Non Peak Days

	BCHydro SCP Peaking Scenario	SCP Scenario Application 2005	SCP/TCPL Scenario not included in Application
Peak Days	• 54 TJ/d T-South Long Haul • 56.5 TJ/d BC Hydro Peaking	• 56.5 TJ/d SCP • 56.5 TJ/d Kingsgate Peaking • 54 TJ/d Huntingdon Resources (Downstream Resources/LNG)	• 54 TJ/d SCP/Incremental TCPL • 56.5 TJ/d Huntingdon Resources (Downstream Resources/LNG)
Non Peak Days	• 54 TJ/d T-South	• Existing TCPL+SCP Capacity+Firm Kingsvale South • Existing Interior Capacity+Firm Kingsvale South (becomes T-South Long Haul Capacity)	• 54 TJ/d SCP/Incremental TCPL
Comment	• BC Hydro has firm access and rights to SCP and Kingsvale South Capacity on day ahead and intraday basis • The 54 TJ/d of T-South is used 120-151 days in the winter months	• TGI has firm access and rights to SCP and Kingsvale South Capacity • This scenario would continue to have the same T-South mitigation as BC Hydro SCP Peaking Scenario given that on non peak days TGI creates T-South Long Haul capacity • This scenario utilizes existing TGI TCPL and Westcoast pipeline capacity on non peak days	• This scenario will be reviewed in the future upon resolution of TCPL negotiations

The fixed costs and the evaluation methodology is the same for both. Both tables have been provided.

Kingsgate Peaking versus BC Hydro SCP Peaking in BCUC IR 3.3 for the 2005/06 GCP

Line		Normal Year	Warm Year	Design Year	Comment
1	Days used	5	0	15	
2	TJ/d	56.5	56.5	56.5	
3	Volume Load Requirement TJ	283	0	848	Line 1 times Line 2
4	**Kingsgate**				
5	Fixed Demand Charge	($399)	($399)	($399)	Conservative estimate. Recent offers are $100K less. This assumes a US$0.05/MMbtu demand charge. Exchange Rate was different in GCP given the timing of the evaluation
6	Average Winter Kingsgate price	$7.59	$0.00	$7.59	Forecasted Kingsgate Winter price at time evaluation done for GCP.
7	Factored price for peak days	2.5	0	2.5	Based on max historical winter volatility
8	Kingsgate midpoint	$18.98	$0.00	$18.98	Line item 6 times 7
9	Net Benefit (Cost) of Kingsgate Peaking	($5,762)	($399)	($16,486)	
10					
11	**BC Hydro SCP**				
12	Average Winter Kingsgate price	$7.59	$0	$7.59	Forecasted Kingsgate winter Price at time evaluation done for ACP
13	Factored price for peak days	2.5	$0	2.5	Based on max historical winter volatility
14	Kingsgate daily midpoint	$18.98	$0	$18.98	Line item 12 times 13
15	Redelivery Diversion Cost	$0.55	$0	$0.55	as per contract charges for calling supply
16	Mark-up Cost (15%)	$2.85	$0	$2.85	as per contract 1.5 times Kingsgate Common High
17	Total commodity cost	$22.38	$0	$22.38	Line item 14+15+16
18	Net Benefit(Cost) of BC Hydro Peaking	($6,322)	$0	($18,967)	
19	Difference Kingsgate Peaking minus BC Hydro Peaking	$561	($399)	$2,480	
20	Difference Kingsgate Peaking minus BC Hydro Peaking-Probability Adjusted	$266	($190)	$124	
21		47.5%	47.5%	5.0%	
22	Total Benefit (Cost) Kingsgate Peaking compared to BC Hydro Peaking-Probability Adjusted	$201			

Kingsgate Peaking versus BC Hydro SCP Peaking in Application

Line		Normal Year	Warm Year	Design Year	Comment
1	Days used	5	0	15	
2	TJ/d	56.5	56.5	56.5	
3	Load Requirement TJ	283	0	848	
4	**Kingsgate**				
5	Fixed Demand Charge	($388)	($388)	($388)	Conservative estimate. Recent offers are $100K less. This assumes a US$0.05/MMbtu demand charge. Exchange Rate was different in GCP given the timing of the evaluation
6	Average Winter Kingsgate price	$8.54	$0.00	$8.54	
7	Factored price for peak days	$2.50	0	$2.50	Based on max historical winter volatility
8	Kingsgate midpoint	$21.35	$0.00	$21.35	
9	Net Benefit (Cost) of Kingsgate Peaking Supply	($6,419)	($388)	($18,482)	
10					
11	**BC Hydro SCP**				
12	Average Winter Kingsgate price	$8.54	$0.00	$8.54	
13	Factored price for peak days	$2.50	0	$2.50	Based on max historical winter volatility
14	Kingsgate daily midpoint	$21.35	$0.00	$21.35	Line item 12 times line item 13
15	Redelivery Diversion Cost	$0.55		$0.55	as per contract charges for calling supply
16	Mark-up Cost (15%)	$2.85		$2.85	as per contract 1.5 times Kingsgate Common High
17	Total commodity cost	$22.38		$22.38	
18	Net Benefit (Cost) BC Hydro Peaking	($7,091)	$0	($21,274)	
19	Difference Kingsgate Peaking compared to BC Hydro Peaking	$672	($388)	$2,792	
20	Net Difference Kingsgate Peaking minus BC Hydro Peaking-Probability Adjusted	$319	($184)	$140	
21		47.5%	47.5%	5.0%	
22	Total Benefit (Cost) Kingsgate Peaking compared to BC Hydro Peaking-Probability Adjusted	$275			

Note: The PGE SCP peaking deals has a quantity of 51.1 TJ/Day and the BC Hydro SCP Peaking deal has a quantity of 56.5 TJ/Day.

4.4 At the bottom of page 8, Terasen Gas refers to very cold days when all of its Westcoast T-south capacity to Savona is required to meet demand requirements in the Interior. Terasen Gas states that to meet demand requirements in the Lower Mainland in this situation, it will acquire additional peaking at Huntingdon, at a net fixed and variable cost of approximately $1.1 to $1.2 million per year. Please provide the calculation showing how this cost was calculated, explaining all assumptions and factors that were used.

Response:

In order to facilitate communication of the portfolio changes in the midstream portfolio, resources were expressed as separate line items in the Application. When the Midstream evaluates the impact of a resource to the existing portfolio it does so as a whole. It is therefore important to note that costs and benefits outlined below are only part of the total costs and benefits and can not be evaluated in isolation. Line items 43 to 46 in Attachment 3b must be evaluated as a whole portfolio. The table below illustrates for simplicity purposes the typical utilization of the resources on peak and non peak days.

Typical Utilization of Resources on Peak and Non-Peak Days

	BC Hydro SCP Peaking Scenario	SCP Scenario Application 2005	SCP/TCPL Scenario not included in Application
Peak Days	• 54 TJ/d T-South Long Haul • 56.5 TJ/d BC Hydro Peaking	• 56.5 TJ/d SCP • 56.5 TJ/d Kingsgate Peaking • 54 TJ/d Huntingdon Resources (Downstream Resources/LNG)	• 54 TJ/d SCP/Incremental TCPL • 56.5 TJ/d Huntingdon Resources (Downstream Resources/LNG)
Non Peak Days	• 54 TJ/d T-South	• Existing TCPL+SCP Capacity+Firm Kingsvale South • Existing Interior Capacity+Firm Kingsvale South (becomes T-South Long Haul Capacity)	• 54 TJ/d SCP/Incremental TCPL
Comment	• BC Hydro has firm access and rights to SCP and Kingsvale South Capacity on day ahead and intraday basis • The 54 TJ/d of T-South is used 120-151 days in the winter months •	• TGI has firm access and rights to SCP and Kingsvale South Capacity • This scenario would continue to have the same T-South mitigation as BC Hydro SCP Peaking Scenario given that on non peak days TGI creates T-South Long Haul capacity • This scenario utilizes existing TGI TCPL and Westcoast pipeline capacity on non peak days	• This scenario will be reviewed in the future upon resolution of TCPL negotiations

Terasen Gas released T-South and incorporated SCP capacity into its portfolio. For design peak days it is assumed for this scenario that Kingsgate peaking flows via SCP to Huntingdon. The remaining days Terasen Gas utilizes its existing TCPL/Duke interior/Kingsvale South capacity resources to flow Alberta or Station 2 supply to Huntingdon. For this exercise to facilitate the understanding of how the release of the T-South capacity may impact the portfolio Terasen Gas evaluated the released T-South with downstream resources for peak days and mitigation of existing resources such as TCPL/SCP capacity and interior/Kingsvale South capacity on non peak days.

$1.1-1.2 million/year savings is based on Terasen Gas replacing Station 2 supply and associated T-south capacity with Huntingdon resources available at the time of the analysis. At the time of the analysis there was only half the requirement available through downstream storage and therefore TGI evaluated the other half with Stanfield supply. These resources would be utilized for peak days and with respect to downstream storage likely for intraday balancing. On non peak days as noted in the table above Terasen Gas would utilize its existing Westcoast Interior capacity and Kingsvale south capacity to flow supply to Huntingdon. Recall again, Terasen Gas replaces the released 54 TJ/d of T-South capacity with peaking resources for peak day requirements and utilizes existing interior Savona/Kingsvale capacity that is flowed to Kingsvale South to create long haul T-South or utilize Terasen Gas' existing TCPL capacity and match to the SCP capacity and Kingsvale South Capacity. The Interior capacity that is used to create T-South long haul capacity on non peak days is the Interior capacity that was picked up under the Terasen /Westcoast negotiated reduced build agreement. This was discussed in Terasen Gas' September 25, 2002 T-South 2003 Renewal Letter to the Commission and the 2003 Annual Contracting Plan. Terasen Gas applies the probability of a normal, warm and design year occurrence to the net costs of each year to determine a total benefit (cost).

Note the combination of Stanfield winter supply and downstream storage resources is a conservative estimated. If Terasen Gas had evaluated the full replacement of the 54 TJ/d of T-South with a downstream storage or LNG resource it would have netted a greater benefit. Due to confidentiality issues with respect to storage costs the fixed and variable charges have been combined under the storage scenario.

Station Winter versus Downstream Storage/Stanfield Winter
Note: T-South charges are included as a separate line item in the Application

Line Item	Attachment 3a Part of Line 49 calculation				
1		Normal Year	Warm Year	Design Year	Comments
2	Days used	5		15	
3	Load Requirement TJ/d	54		54	
4	**Station 2 Winter**				
5	Volume Required for Load TJ	270	0	810	Line item 2 time line item 3
6	Average Winter Station 2 Price Cdn$/GJ	$7.99	$0	$7.99	Forecasted Station 2 Winter price

7	Factored price for peak days	1.5	0	1.5	Calculation of 5 year maximum daily price volatility.
8	Station 2 daily midpoint	$11.99	$0	$11.99	Line item 6 times line item 7
9	Net Benefit (Cost) of Station 2 winter supply	($3,236)	$0	($9,708)	Net Cost of Station 2 supply
10					
11	**Stanfield**				
12	Volume Required for Load TJ	135	0	405	Load Requirement times number of days required
13	Average Winter Stanfield Price	$8.64	$0	$8.64	Forecasted Stanfield Winter price
14	Factored price for peak days	2.5	0	2.5	Calculation of 5 year maximum daily price volatility.
15	Stanfield daily midpoint	$21.60	$0	$21.60	Line item 12 times 13
16	Volume Required for Load	135	0	405	
17	Net Benefit (Cost) of Stanfield Winter Supply	($2,916)	$0	($8,748)	Net cost of Stanfield supply
18					
19	**Downstream Storage**				
20	Volume Required for Load TJ	135	0	405	Load Requirement times number of days required
21	Fixed and Variable Charges	($2,017)	($605)	($4,596)	Includes demand charges, summer variable charges and mitigation of excess storage
22	Net Benefit (Cost) Stanfield and Downstream Storage	($4,933)	($605)	($13,344)	Line item 21 + line item 17
23	Difference Downstream Storage/Stanfield Resource compared to Station 2 Winter Supply	($1,698)	($605)	($3,636)	Line item 22 minus Line item 9
24		47.5%	47.5%	5.0%	Probability of load occurrence
25	Total Benefit (Cost) Downstream Storage plus Stanfield winter supply versus Station 2 winter supply-Probability Adjusted	($1,278)			Line items 23 times Line items 24

4.5 With the termination of 54.0 TJ/d of Westcoast T-south from Station 2 to Huntingdon, Terasen Gas proposes to replace Station 2 supply with supply from downstream of Huntingdon. The response to BCUC IR 3.2 for the 2005/06 GCP indicates an increase of approximately $2 million in annual gas costs for the scenario where the BC Hydro peaking continues to be available and no T-south is released. However, BCUC IR 3.2 did not ask Terasen Gas to assume there was no release of T-south capacity. Please repeat the question on the basis that the BC Hydro/Terasen Inc. TSA and Peaking Agreement continue in effect, and that the 54.0 TJ/d of T-south from Station 2 to Huntingdon has been decontracted. If necessary, please assume that interruptible T-south service will be available.

<u>Response</u>:

Terasen Gas is assuming that the Commission is requesting an evaluation of replacing 54 TJ/d of firm supply in the Midstream portfolio with 54 TJ/d of interruptible supply. Terasen Gas' obligation is to contract supply resources which secure reliable natural gas deliveries to meet Core customer design peak day while mitigating against upstream and downstream supply disruptions. This obligation exists in determining our optimal start point and other scenarios are evaluated against peak day requirements. Evaluating the portfolio under other assumptions such that that interruptible T-South capacity is available would be evaluated along with other available resources. The table below illustrates for simplicity purposes the typical utilization of the resources on peak and non peak days.

	BC Hydro SCP Peaking Scenario	SCP Scenario Application 2005	SCP/TCPL Scenario not included in Application
Peak Days	• 54 TJ/d T-South Long Haul • 56.5 TJ/d BC Hydro Peaking	• 56.5 TJ/d SCP • 56.5 TJ/d Kingsgate Peaking • 54 TJ/d Huntingdon Resources (Downstream Resources/LNG)	• 54 TJ/d SCP/Incremental TCPL • 56.5 TJ/d Huntingdon Resources (Downstream Resources/LNG)
Non Peak Days	• 54 TJ/d T-South	• Existing TCPL+SCP Capacity+Firm Kingsvale South • Existing Interior Capacity+Firm Kingsvale South (becomes T-South Long Haul Capacity)	• 54 TJ/d SCP/Incremental TCPL
Comment	• BC Hydro has firm access and rights to SCP and Kingsvale South Capacity on day ahead and intraday basis • The 54 TJ/d of T-South is used 120-151 days in the winter months •	• TGI has firm access and rights to SCP and Kingsvale South Capacity • This scenario would continue to have the same T-South mitigation as BC Hydro SCP Peaking Scenario given that on non peak days TGI creates T-South Long Haul capacity • This scenario utilizes existing TGI	• This scenario will be reviewed in the future upon resolution of TCPL negotiations

		TCPL and Westcoast pipeline capacity on non peak days	

Under the BC hydro peaking scenario if Terasen Gas were to decontract T-South long haul Terasen Gas would have to acquire another firm resource to meet not only the 15 peak days but the 120-151 winter days. If Terasen Gas were to evaluate another firm resource to replace T-South under the BC Hydro peaking scenario it would have to make that similar assumption under the T-South decontracting scenario. Therefore, both scenarios would take advantage of any cost savings associated with another 120-151 day resource. The table below illustrates the similarity and differences between the scenarios if T-South was decontracted.

4.6 The response to BCUC IR 3.5 regarding the 2005/06 GCP indicates that the calculated savings for releasing 54.0 TJ/d of T-south does not recognize that a material part of the cost of service of this capacity is likely to be allocated back to Terasen Gas through the tolls that Terasen Gas will pay for the other Westcoast service that it will continue to hold. Further to the response to BCUC IR 3.6, please provide detailed information for 2005/06 about estimated total Westcoast T-south cost of service, total contractable T-south capacity, total contracted T-south capacity, Terasen Gas contracted T-south capacity with and without the 54.0 TJ/d, other T-south capacity for which Terasen Gas pays or reimburses toll charges, projected interruptible T-south revenue that is likely to reduce the Westcoast cost of service and any other information that is relevant to the calculation of net Terasen Gas T-south payments.

Response:

Please refer to the tables on the following page.

The tables below outline Terasen Gas assumptions in calculating the Duke Toll for 2006

Table: WEI COS (2005 and 2006)

	2005	2006
WEI Cost of Service:	$200,576,000	$205,590,400
Assume: 2.5% Increase from 2005 to 2006		

Table: WEI Capacity — **All numbers in mmcf/d**

	Total Contractable	Total Contracted	Terasen Gas After Decontracting	Terasen Gas Before Decontracting
PNG	110	40	0	0
Interior	207	197	129	129
Kingsvale South	105	105	105	105
Huntington	1597	938	338	388
Tersen Gas T-South includes Tri-Party				

Table: IT Revenue

WEI IT Revenue Forecas	Before Decontract	$34,000,000
	After Decontract	$43,000,000

Assumes historic seasonal flows to Huntington
IT Toll is calculated based on WEI proposals
Flow Changes caused by gain or loss of load in the PNW region or changes in NWP Gorge flow will impact the IT revenue and potentially the WEI toll

Table: Tolls and Amount Paid by Terasen Gas for 2006 Before and After 50 mmcf/day T-South Long Haul Turnback

	Toll Before $/mcf	Toll CD Before mmcf	Total Toll Before $Cdn	Toll After $/mcf	Toll CD After mmcf	Total Toll After $Cdn
Interior	$0.2256	129	$10,622,376	$0.2234	129	$10,518,789
Kingsvale South	$0.1818	105	$6,967,485	$0.1800	105	$6,898,500
Huntington	$0.4073	388	$57,681,826	$0.4035	338	$49,779,795
Total			**$75,271,687**			**$67,197,084**
Net Savings after Decontracting and toll adjustment to Terasen Gas for 2006:						**$8,074,603**

Table: Segmentation Savings Based on Turnback of Capacity held by Terasen Gas

	Toll Before $/mcf	Toll CD Before mmcf	Total Toll Before $Cdn	Toll After $/mcf	Toll CD After mmcf	Total Toll After $Cdn
Interior	$0.2256	55	$4,528,920	$0.2234	0	$0

As a result of segmentation of 105 mmcf/d of WEI TS Long Haul in 2003, Terasen Gas was able to increase its WEI CD by 50 mmcf/d and reduce its WEI toll responsibility equal to 55 mmcf/d of Interior capacity resulting in a savings of about $4.528 million based on the forecast 2006 toll. These saving were the direct result of the construction of SCP.

Note: In the absence of segmentation WEI tolls in 2006 would have been higher as a result of a more costly 2003 expansion and we have not included any of these benefits in Terasen Gas anaylsis.

Terasen Gas would see a net reduction in its payment to WEI for 2006 by $8.074 million by turning back 50 mmcf/day of WEI T- South Long Haul.

It is Interesting to note that if you assume the 50 mmcf/day of T-South Long Haul capacity that is turned back by Terasen Gas was the last increment of turn back, Terasen Gas customers see a net reduction on unit tolls ($.4073/mcf to $.4035/mcf). This is based on the assumption that the 50 mmcf/day is utilized at 100% load factor and flows on the IT rate thru the winter at 133% of the firm toll and at 100% of the firm toll for summer requirements.

Terasen Gas anticipates that Westcoast's current toll for T-South Long Haul ($.33/mcf) for 2005 will increase to a toll in the range of $.38 mcf/day to $.43 mcf/day which is significantly higher cost than the SCP capacity available through the exercising of the BC Hydro put option.

4.7 Please use the information in the preceding response to calculate the total Terasen Gas T-south charges with and without the 54.0 TJ/d of T-south, and estimate the net savings to Terasen Gas of releasing the 54.0 TJ/d of T-south. Please use Terasen Gas's current estimate of Westcoast cost of service in the calculation, and do not make further adjustments for such factors as the impact of the reduction in Westcoast's 2003 expansion or lower Station 2 commodity demand premiums.

Response:

See BCUC IR1 - Response to 4.6.

4.8 With segmentation of Westcoast T-south service and tolls, please confirm that, at most, T-south service from Kingsvale to Huntingdon would be needed to provide SCP transportation service to BC Hydro. If Terasen Gas has a different view, please explain.

Response:

Yes with Segmentation, Kingsvale South transportation provides transport on a firm basis for NWN, Terasen Gas core and BC Hydro.

4.9 What is the annual cost of 54.0 TJ/d of T-south Kingsvale to Huntingdon service? What would be the net savings to Terasen Gas, after redistribution of Westcoast's lost revenue, of canceling this amount of service?

Response:

Annual cost of the 54 TJ/d of Kingsvale to Huntingdon capacity is about $2.7 million, based on 2005 Westcoast Tolls.

In return for the segmentation and the significant annual savings that flowed to Terasen Gas firm customers as a result of entering into the agreement with Westcoast for a reduced build on Westcoast, Terasen entered into a 15 year agreement with Westcoast commencing November 1, 2003 for the entire 105,000 mmcf/d. This Kingsvale South capacity with a term of 15 years was approved by the Commission in the 2003 Annual Contracting Plan.

As such there are no net savings from cancelling this service. In fact, the reduced toll from segmentation for calendar year 2006 is estimated to be almost $4.1 million and this does not include any savings associated with the reduction in the costs associated with the Westcoast 2003 expansion that would apply to all Terasen Gas capacity and the capacity held by its transportation customers.

4.10 To the extent that return of BC Hydro SCP service permits Terasen Gas to terminate Westcoast T-south service, should the credit for such termination be the net savings for terminating Kingsvale to Huntingdon service. If not, please explain.

Response:

No. The Kingsvale to Huntingdon service is the bottom or second leg to ensure the flow path from EKE, along SCP to Kingsvale can then deliver supply to the Lower Mainland. Cost savings achieved via the segmentation have already been accounted for within the midstream portfolio. Taking the SCP capacity back now allows Terasen to match SCP with the Kingsvale South (Duke) capacity, completing the flow path to get supply to the Lower Mainland.

5.0 Reference: Exhibit B-1, pp. 7-10
Release of 54.0 TJ/d of Westcoast T-south

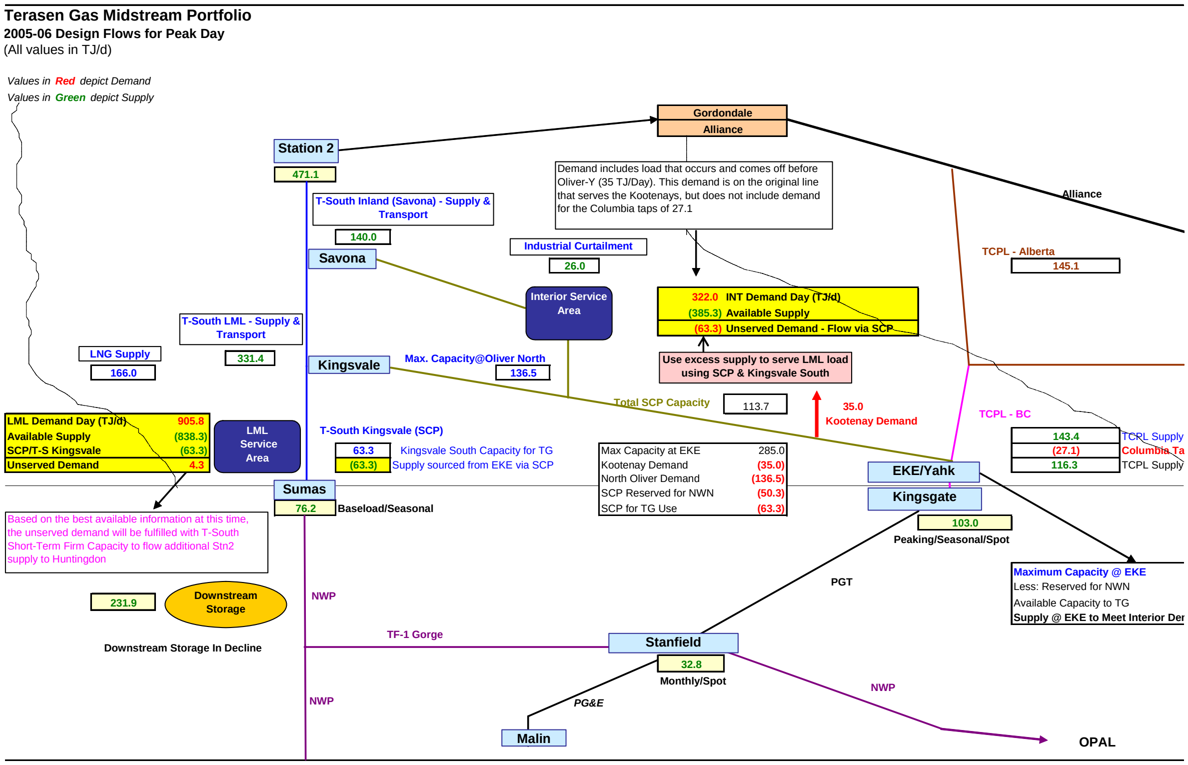
5.1 Notwithstanding that Terasen Gas may have realized cost savings by terminating T-south and replacing gas supply at Station 2 with supply downstream of Huntingdon, it would appear that the cost savings should only be allocated to the request to accept the BC Hydro SCP capacity into the Midstream portfolio if the return of the BC Hydro SCP capacity was a necessary condition for terminating the T-south. In response to BCUC IR 3.7 regarding the 2005/06 GCP, Terasen Gas states that all of the T-south Interior and TCPL capacity is required to meet peak day demand in the Interior service area. Further to Figure 14 on page 141 of the 2005/06 GCP, please confirm that the situation with the BC Hydro SCP capacity in the Midstream portfolio can be summarized as follows, or provide any corrections.

Interior (Inland and Columbia) peak day demand – ______TJ/d

Supply:	*T-south to Savona*	____ *TJ/d*	
	T-south to Kingsvale	____ *TJ/d*	
	TCPL – BC	____	
	Kingsgate supply	_____	
	Industrial curtailment	_____	
			_____ *TJ/d*
Surplus supply to Interior			____ *TJ/d*

Response:

The diagram below outlines the supply resources and flows to meet the peak day and this is consistent with what was filed in Terasen Gas' Midstream Annual Contracting Plan and also matches the table above.



The table below illustrates for simplicity purposes the typical utilization of the resources on peak and non peak days.

Typical Utilization of Resources on Peak and Non Peak Days

	BC Hydro SCP Peaking Scenario	SCP Scenario Application 2005	SCP/TCPL Scenario not included in Application
Peak Days	• 54 TJ/d T-South Long Haul • 56.5 TJ/d BC Hydro Peaking	• 56.5 TJ/d SCP • 56.5 TJ/d Kingsgate Peaking • 54 TJ/d Huntingdon Resources (Downstream Resources/LNG)	• 54 TJ/d SCP / Incremental TCPL • 56.5 TJ/d Huntingdon Resources (Downstream Resources/LNG)
Non Peak Days	• 54 TJ/d T-South	• Existing TCPL+SCP Capacity+Firm Kingsvale South • Existing Interior Capacity+Firm Kingsvale South (becomes T-South Long Haul Capacity)	• 54 TJ/d SCP/Incremental TCPL

Comment	• BC Hydro has firm access and rights to SCP and Kingsvale South Capacity on day ahead and intraday basis • The 54 TJ/d of T-South is used 120-151 days in the winter months •	• TGI has firm access and rights to SCP and Kingsvale South Capacity • This scenario would continue to have the same T-South mitigation as BC Hydro SCP Peaking Scenario given that on non peak days TGI creates T-South Long Haul capacity • This scenario utilizes existing TGI TCPL and Westcoast pipeline capacity on non peak days	• This scenario will be reviewed in the future upon resolution of TCPL negotiations

To clarify, the interior capacity is made up of T-South Inland (“ T-south to Savona” noted above) and the T-South Inland that will flow into Savona on days the Interior required the supply but can also flow to Kingsvale (“T-South to Kingsvale”) identified above. The supply flowing from Station 2 on the T-South Inland (both “T-south to Savona and T-South to Kingsvale” identified above) is delivered into the Interior via Savona on peak days.

The line item identified as “Surplus supply to interior” in the table above is supply that would flow from Kingsgate to Huntingdon to meet lower mainland core customer load requirements under this scenario. This volume identified as “Surplus supply to interior” flows from Kingsgate via SCP and T-South Kingsvale South capacity to Huntingdon for Lower Mainland consumption.

Terasen Gas would not have terminated Westcoast L H capacity (September 2004, effective November 2005) without having firm access to the SCP capacity.

5.2 Please discuss whether a description of this situation from a physical flow perspective would be that the _____ TJ/d of gas that comes down Westcoast T-south to Kingsvale, plus a small amount of gas that moves west on SCP to Kingsvale, would be transported on to Huntingdon on the _____ TJ/d of T-south Kingsvale to Huntingdon service that Terasen Gas holds in addition to the capacity needed to provide SCP service to NW Natural. In other words, please confirm that the T-south deliveries to Kingsvale are not needed to meet the Interior peak day demand.

Response:

T-South deliveries to Kingsvale (54TJ) are not required to meet peak day for the Interior. These volumes are diverted through Savona.

Please see BCUC IR Response No. 5.1. On a design peak day the Kingsvale to Huntingdon capacity would then be used to flow Kingsgate peaking supply that comes from Kingsgate via SCP capacity.

5.3 The response to BCUC IR 3.10 regarding the 2005/06 GCP states that the return of the BC Hydro SCP capacity was essential for the release of 54.0 TJ/d of T-south long haul capacity. The response to BCUC IR 3.11 regarding the 2005/06 GCP does not take issue with the presumption in the question that the situation with respect to T-south (and the release of it) is the same for the first 15 coldest days whether Terasen Gas is receiving BC Hydro peaking or is using the SCP capacity and sourcing peaking gas at Kingsgate. If Terasen Gas does disagree with the presumption that, with respect to the 15 coldest days, continuation of the BC Hydro/Terasen Inc. TSA and Peaking Agreement would not preclude the release of the 54.0 TJ/d of T-south capacity, please explain Terasen Gas' position in detail, and include a diagram that is similar to Figure 14 on page 141 of the 2005/06 GCP to support it.

<u>Response</u>:

Terasen Gas would not have been able to release Westcoast L H capacity prior to BC Hydro exercising their Put option. Terasen Gas turned back 54 TJ/day of Westcoast service (exchanged Westcoast for SCP) and replaced the BC Hydro Peaking arrangement with a new peaking resource at Huntingdon. For days 16 forward, there is now a firm path available on SSCP from EKE to Huntingdon to replace the path from Station 2 to Huntingdon.

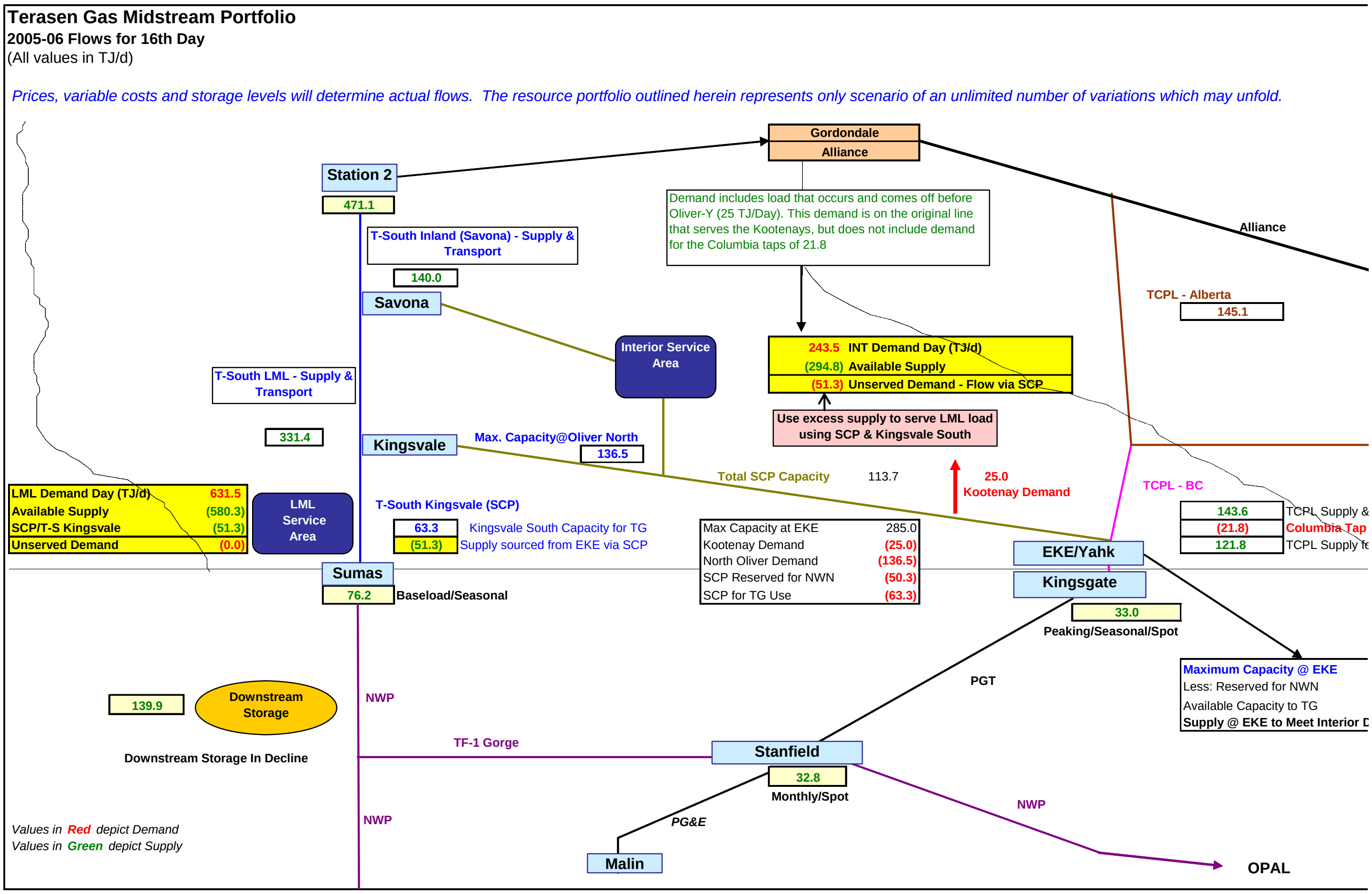
5.4 It is not clear from the response to BCUC IR 3.11 regarding the 2005/06 GCP why the situation on the 16th coldest and warmer days would have prevented the release of 54.0 TJ/d of T-south capacity for 2005/06, notwithstanding that the BC Hydro/Terasen Inc. TSA and Peaking Agreement continued in effect. The response to BCUC IR 3.11 indicates that the Interior demand on the 16th coldest day is _____ TJ/d, while the supply is as follows:

T-south to Savona	_____	*TJ/d*
T-south to Kingsvale	_____	
TCPL – BC	_____	
Kingsgate supply	_____	
Curtailment	_____	
Total Supply	_____	
Adjust Kingsgate to ____ TJ/d	_____	*(same as peak day)*
Reduce for BC Hydro/Terasen Inc.	*-56.5*	
Remove T-south to Kingsvale	_____	
Net Interior Supply	_____	

Please confirm that supply to the Interior would not be a constraint to the release of the 54.0 TJ/d of T-south, and that the supply available via T south to Kingsvale would not have been needed.

<u>Response</u>:

The diagram below outlines the supply resources and flows to meet the 16th coldest day.



Supply could be reduced on the 16th day but this is not the Design Day. Under the released SCP scenario Terasen Gas has firm access to the SCP and Kingsvale South capacity. On days other than the 15 peak days Terasen Gas can flow supply from either Terasen Gas' existing Interior capacity to Kingsvale and then to Huntingdon or from Terasen's existing TCPL capacity to SCP to Kingsvale South then to Huntingdon.

Under the BC Hydro scenario the option to use Kingsvale to Huntingdon capacity is not available given BC Hydro has firm day ahead and intraday rights and access.

5.5 *The response to BCUC IR 3.11 regarding the 2005/06 GCP indicates that on the 16th coldest day, the demand in the Lower Mainland is ____ TJ/d. Based on Figure 14 on page 141 of the 2005/06 GCP for the peak day, the following would appear to be the situation on the 16th coldest day:*

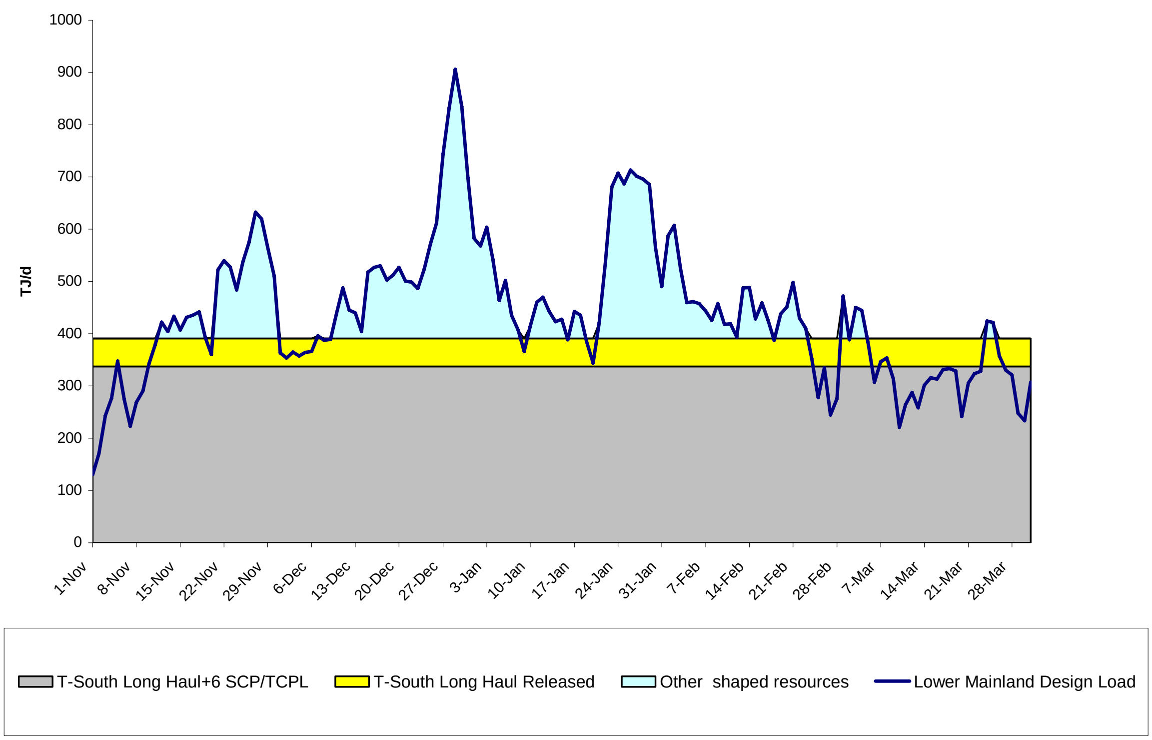
Peak day supply	______	*TJ/d (Excludes ___ TJ/d of SCP)*
Remove LNG supply	______	
Add residual SCP (_______)	______	*(Reserve 56.5 TJ/d for BC Hydro)*
Net supply to Lower Mainland	______	*TJ/d*

Please confirm or correct the foregoing information.

Response:

The request assumes an ability of all resources to be optimal and sequencing of the coldest day to be known. Please refer to a lower mainland design scenario in the chart below. The supply situation as indicated in "Net supply to Lower Mainland" would include about 232 TJ/d of shaped (less than 26 days) downstream storage and assumes the storage levels are not in decline. So the "Net supply to Lower Mainland" may range from 450-679 TJ/d on the 16th coldest day depending on the level of downstream storage. BCUC IR 3.11 was a depiction of one scenario as indicated in the answer to BCUC IR 3.11.

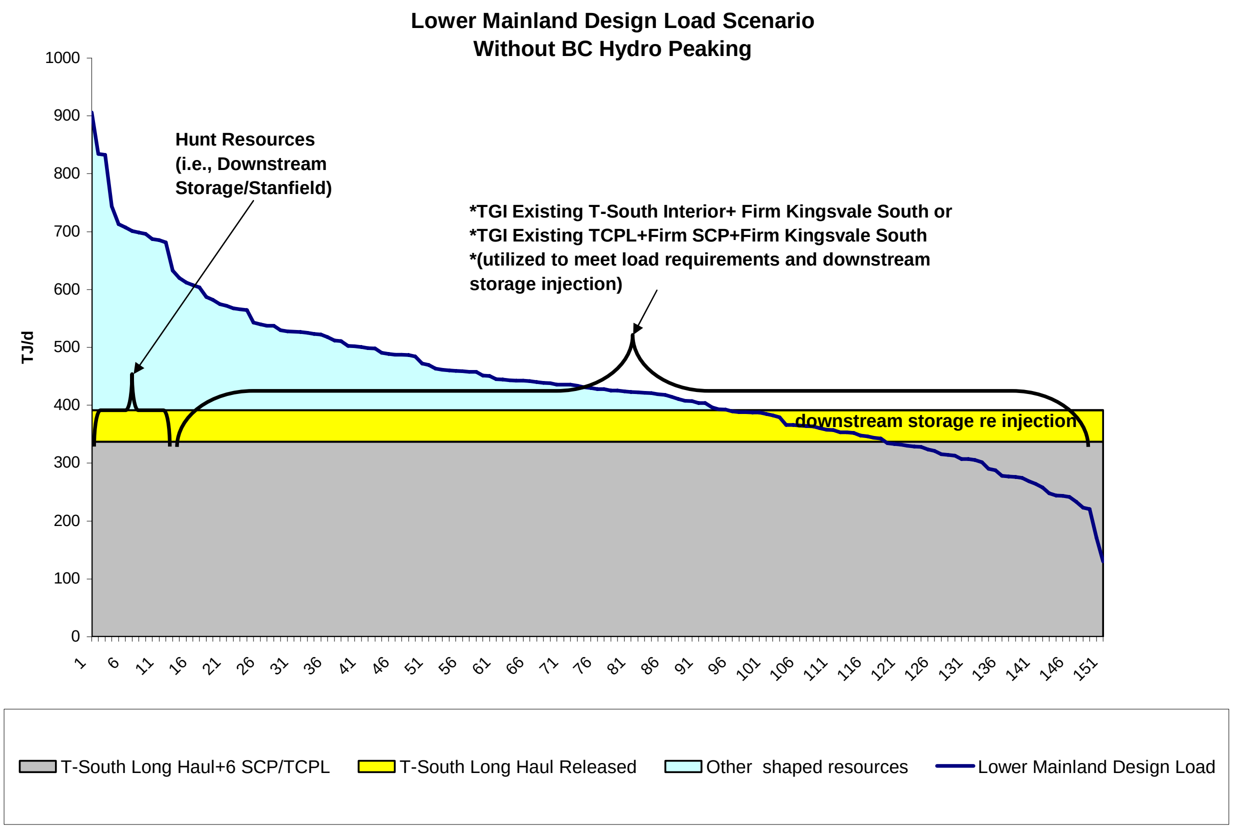
Lower Mainland Design Load Scenario



5.6 If Terasen Gas considers that supply on the 16th coldest day and warmer days would be a problem without the 54.0 TJ/d of T-south and with the BC Hydro/Terasen Inc. agreements in place, please provide a detailed explanation of the Terasen Gas position and diagrams similar to Figure 14 of the 2005/06 GCP that support it. The explanation should address situations when BC Hydro/Terasen Inc. are, and are not, flowing gas.

Response:

Please refer to the chart below. This chart is the same information from the chart in BCUC IR# 5.6; however it is depicted as a load duration curve. The T-South released area in yellow was the T-South used in the BC Hydro SCP Peaking scenario and was required for more than 15 days and was used to meet load requirements and re inject into downstream storage when not required to meet load requirements. In the scenario without BC Hydro SCP Peaking the released T-South capacity is replaced with a Huntingdon peaking resources and utilization of Terasen Gas' existing Westcoast Interior capacity and firm Kingsvale South or Terasen Gas' existing TCPL capacity and firm SCP and Kingsvale South.



6.0 Reference: Exhibit B-1, pp. 7-10
BC Hydro Put Option

On page 7 the Application states: "…BC Hydro also negotiated a Put Option with Terasen Inc. (then BC Gas Inc.), that allowed BC Hydro to assign the transportation service and peaking gas agreements to Terasen Inc. for the remaining period…" It also states: "BC Hydro provided notice to Terasen Gas and Terasen Inc. on September 15, 2004, that it was exercising its Put Option…"

6.1 Please explain the rationale why the Put Option was written by Terasen Inc.

Response:

In the BCUC Decision dated April 3rd, 1998, the Commission denied Terasen Gas's (then BC Gas Utility) May 1997 CPCN Application for SCP. In part, the decision to deny the application was due the lack of firm third party commitments from transportation customers that would increase the utilization of the pipeline and offset a portion of the costs of the project. In addition, the Commission encouraged Terasen Gas to explore peaking gas arrangements with BC Hydro related to expected transportation arrangements required to serve Burrard Thermal and proposed generation facilities on Vancouver Island. At the time BC Hydro had issued an Request for Proposals for transportation capacity to serve both Burrard and Vancouver Island. As a result of that process, BC Hydro subsequently entered into the Bypass Transport Agreement (BTA) and began development of the Georgia Strait Crossing (GSX) in partnership with Williams.

Subsequently, Terasen Gas negotiated TSA and Peaking Agreements with both BC Hydro and PG&E which provided for firm third party revenues. These agreements supported Terasen Gas's December 1998 CPCN application for SCP which was subsequently granted by Commission Decision dated May 1999.

During the discussions, BC Hydro's stated that as a condition of putting the TSA and Peaking Agreement in place, it required the flexibility to release the SCP capacity and peaking gas obligation in the future. As a result, BC Hydro, BC Gas Utility and BC Gas Inc agreed to the Put Option Agreement whereby BC Hydro had the right to assign the TSA and Peaking Agreement to BC Gas Inc (now Terasen Inc) upon approximately 13 month notice. Terasen Inc agreed to provide this backstopping service to BC Gas Utility so that the utility could demonstrate in its May 1999 CPCN application that the third party revenues to offset the costs of the pipeline were firm.

In addition, Terasen Inc believed that BC Hydro would require firm transportation service upstream from Sumas to serve Burrard Thermal and its gas fired strategy for Vancouver Island, and that proposed SCP service would be a low cost option compared to contracting for firm long term transportation service on Westcoast. In view of the commitments BC Hydro was making vis-à-vis the BTA, GSX and subsequently Westcoast expansion capacity it was therefore felt that it was a low probability that BC Hydro would exercise the put option.

6.2 Did BC Hydro provide consideration to obtain the right to the Put Option? If so, please describe the consideration and whom it was paid to.

Response:

No.

6.3 Did BC Hydro pay any type of termination fee to Terasen Gas Inc. or to Terasen Inc. when the Put Option was exercised? If so, please elaborate.

Response:

No.

6.4 What were the restrictions to BC Hydro on its ability to re-assign its TSA, Peaking Agreement, and Put Option to a third-party? Will Terasen Inc. have the same rights of assignment?

Response:

The applicable clauses in each of the agreements are summarised in the table below. BC Hydro had the right to assign its TSA and Peaking Agreement to any other party provided it first obtained written approval from Terasen Gas, such approval not to be unreasonably withheld. The Put Option Agreement was not assignable. Pursuant to clause 4.1.1 of the Put Option Agreement, by exercising the option, BC Hydro is deemed to have assigned the TSA and Peaking Agreement to Terasen Inc (then BCGI). Terasen Inc would therefore have the assignment rights as provided by Clause 19.1 of the TSA and Clause 15.2 of the Peaking Agreement.

Agreement/ Reference	Assignment Rights
TSA Clause 19.1	*"This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns. No assignment or transfer by either Party shall be made without written approval of the other Party. Such approval shall not be unreasonably withheld. Unless otherwise agreed between the Parties, such assignment shall become effective on the first Day of the Month following written notice that such assignment has been effected."*

Agreement/ Reference	Assignment Rights
Peaking Agreement Clause 15.2	*"This Agreement may not be assigned by either party except with the prior written consent of the other. No such assignment shall be effective unless and until the assignee shall have executed and delivered to the other party an agreement in writing whereby the assignee agrees to be bound by the assignor's obligations under this Agreement and no such assignment shall release such assignor from its duties and obligations under this Agreement, unless expressly consented to in writing by the other party."*
Put Option Agreement Clause 6.1	*"This Put Option Agreement may not be assigned by any of the parties."*
Put Option Agreement Clause 4.1.1	*"Hydro shall be deemed to have assigned and transferred to BCGI, with consent and approval of BC Gas all of its right, title and interest in and to the Put Agreements, to the extent such Put Agreements are outstanding and in force and effect on the Effective Date;"*

6.5 If BC Hydro exercised its Put Option and Terasen Inc. then continued to hold the transportation service and peaking gas obligations, how would Terasen Inc. be able to realize benefits beyond its obligated costs? Please explain and quantify.

Response:

BC Hydro has exercised its Put Option and unless otherwise approved, Terasen Inc would assume the rights and obligations associated with the TSA and Peaking Gas Agreement effective November 1, 2005. The Primary Term of these agreements expire on October 31, 2010, after which Terasen Inc could elect but is not obligated to extend the TSA for additional one year terms. (Article 8 of the TSA allows for renewal terms for periods of one Contract Year provided the Shipper gives 24 months written notice, and that the total term of the agreement does not exceed 20 years.) Any extension of the TSA results in an automatic extension of the Peaking Agreement pursuant to Article 2 of the Peaking Agreement.

The current proposal is that Terasen Inc and Terasen Gas agree to terminate both the TSA and the Peaking Agreement effective November 1, 2005 as part of the total package of arrangements presented in the Application, including recovery of the IPC development costs. Terasen Gas would incorporate the SCP capacity into its Midstream Portfolio and subsequently optimise its other holdings. As described in the Application, this arrangement is expected to deliver between $2.2 and $3.2 million *(reference. Line 52 in Attachment 3a and Attachment 3b in Exhibit B3)* in savings to Terasen Gas after adjusting for replacement of the peaking arrangements and revenue from BC Hydro's demand charges.

Alternatively, if the SCP Agreements are not terminated and Terasen Inc continued to hold the transportation service and peaking gas obligations, Terasen Inc would seek to mitigate the cost of holding these agreements by putting in place other types of arrangements with Terasen Gas and/or third parties. Due to the significant benefits to Terasen Gas's customers for use of this capacity, Terasen Inc has not pursed any third party transactions at this time.

An alternative arrangement could be structured whereby Terasen Inc continues to hold the TSA and Peaking Agreement and separately puts in place a bypass type agreement with Terasen Gas whereby the utility would have full use of the capacity and would pay Terasen Inc demand charges that are based on a discount to its avoided costs. Under this structure Terasen Inc would continue to pay the $3.6 million demand charges to Terasen Gas, however Terasen Gas would in turn pay to Terasen Inc a significant share of the savings to its Midstream Portfolio. Depending on the term of the new agreement, Terasen Inc would also retain the opportunity to contract with third party customers in the future as regional capacity becomes more constrained by exercising its rights to renew the SCP Agreements after 2010.

Under this structure, Terasen Gas would continue to optimise its Midstream portfolio utilising the SCP capacity as proposed in the Application, however a significant portion of the net cost savings would be shared with Terasen Inc. The following table provides an example of the expected net benefits to Midstream and to Terasen Inc based on the expected value of the transactions over the contract year 2005/06 as provided in Table 3 of Attachment 3a and 3b Exhibit 3. Terasen Inc would be replacing the BC Hydro demand charges allocated to the delivery margin, therefore there would be no impact from the current status quo on SCP mitigation revenue against the delivery margin.

$000s	Contract Year 05/06	
VALUE TO TERASEN GAS	Attach 3a	Attach 3b
Net Benefits before SCP Allocation (Line 52 plus Line 48)	5,770	6,591
Demand Charge to Terasen Inc (based on 90% of Midstream Portfolio Savings)	- 5,193	-5,932
Net Savings to Terasen Gas (Midstream)	577	659

$000s	Contract Year 05/06	
VALUE TO TERASEN INC	Attach 3a	Attach 3b
TSA Demand Charges to Terasen Gas	- 3,600	-3,600
Demand Charges from Terasen Gas (based on 90% of TGI Savings)	5,193	5,932
Net Benefit to Terasen Inc	1,593	2,332

6.6 Noting that BC Hydro gave notice exercising its Put Option on September 15, 2004, please identify the amount of BC Hydro revenue that Terasen Gas included in its 2005 revenue requirements estimate for the 2004 Annual Review, and justify this amount. If $3.6 million of revenue was forecast for 2005 and the TSA for this service is terminated effective November 1, 2005, what are Terasen Gas' views on recording the revenue variance for 2005 in the SCP Deferral Account?

Response:

As stated in the Company's Annual Review submission, dated October 29, 2004 on Tab 4, page 10, "This revenue reflects the anticipated cancellation of the BC Hydro contract at the end of October 2005 and assumes that a replacement customer will be found to offset this loss staring November 2005." The revenue from BC Hydro for the 2005 test year was $3.0 million covering the period from January through the end of October. . Based on the Company's proposal in its Application, Terasen Gas submits there is no expectation of a revenue variance, as there would be a credit to the delivery margin account commencing November 1, 2005.

7.0 Reference: Exhibit B-1, pp. 7-10; Appendix 3a, 3b
Requested Approvals Related to the BC Hydro SCP Capacity

7.1 On page 4, the Application seeks approval to terminate the TSA and Peaking Agreement currently held with BC Hydro and to be assigned to Terasen Gas Inc. as of November 1, 2005. Please confirm that this request is made on the understanding, consistent with Letter No. L-48-02, that Terasen Gas will be "reimbursed (by Terasen Inc.) for any net costs or losses that result."

Response:

No, the request is being made with the understanding that Terasen Gas is not expected to realize any net costs or losses. In fact, Terasen Gas has evaluated its midstream portfolio and determined that significant savings will be realised if it accepts the SCP capacity back for its own use. These savings can be forecast with reasonable certainty over the 5 year period from November 2005 to October 2010, in other words to the end of the primary term of the agreements. In other words, the transactions crystallize the benefits for Terasen Gas customers for the total period; there are no losses to consider.

Under the proposed arrangements, Terasen Inc would not have any further obligation to compensate Terasen Gas based on actual costs and benefits. Nor would Terasen Inc have any right to any of the actual savings realised by Terasen Gas as a result of the arrangements.

7.2 Considering the amount of uncertainty in any forecast of the amount of any such net costs or losses, is there any reason that prevents the reimbursement from being based on annual after-the-fact assessments of the actual costs and benefits?

Response:

Terasen Gas has evaluated its midstream portfolio in a manner consistent with normal annual contracting practices and determined that it will realise significant benefits as described in the Application. As the majority of these benefits result from net reduction in fixed costs associated with transportation, storage and peaking arrangements these can be forecast with reasonable certainty over the applicable period, November 2005 to October 2010. In other words, the transactions crystallize the benefits for Terasen Gas customers for the total period; there are no losses to consider.

Please also refer to response to BCUC IR, 7.1.

7.3 The Application on page 4 seeks approval to include the 52.5 MMcfd of BC Hydro SCP capacity in the Midstream resource portfolio effective November 1, 2005 and to make adjustments to its other transmission and peaking capacity resources. Please confirm that these matters are addressed in the 2005/06 GCP and that the recommended Midstream portfolio for 2005/06 is based on this scenario.

Response:

Yes these matters are addressed in the 2005/06 GCP and that the recommended Midstream Portfolio for 2005/06 is based on this scenario.

7.4 The Application at page 4 seeks approval for an annual allocation of $3.6 million to be debited against the Midstream Cost Reconciliation Account ("MCRA"), with an offsetting amount to be credited to the delivery margin account, for the period commencing November 1, 2005 and ending November 1, 2010. The Application at page 8 states that, as a result of using the BC Hydro SCP capacity as part of the Midstream portfolio, 54.0 TJ/d of T-south long haul capacity can be released, leading to savings of $8 to $9 million per year that are realized as a reduction to costs recorded in the MCRA.

7.4.1 Please provide a brief description of how Westcoast charges, mitigation revenue from the third party use of Westcoast service contracted by Terasen Gas, gas cost savings resulting from being able to receive gas at one point or another on the Terasen Gas system and revenue from the BC Hydro TSA and PG&E TSA have been recorded by Terasen Gas in the past.

Response:

Terasen Gas has included the Westcoast pipeline service demand charges in the Midstream cost account (and in the past, the GCRA). The revenue from the BC Hydro TSA and PG&E TSA has been captured and reported in the SCP deferral account. All mitigation activities are reported in the annual GSMIP filing with the BCUC. This includes any mitigation activities on SCP. A percentage of revenue from T-South mitigation and T-South/SCP mitigation has been allocated to the SCP deferral account based upon volumes of contracted service.

For example, in 2002/03, 57% of the transport mitigation revenue from T-South was allocated to the SCP account with the remaining 43% being allocated to GSMIP. This percentage was based on the proportion of Terasen Gas T-South left open (i.e. 84 TJ/d of Station #2 gas to fill this transport was not termed up for the winter) versus the amount of T-South dedicated to BC Hydro and PG&E SCP transport (113 TJ/d in total). So, 84 / (84 + 113) = 43%. During the summer months when Terasen Gas has considerably more open, or unutilized, T-South, the percentage allocated to the SCP account is less, based on the dedicated SCP T-South volumes versus the Terasen Gas held T-South. For example, in

2002/03 the percentage allocated to GSMIP was 80% with the remaining 20% going to the SCP account. This is based on the formula of 113 TJ/d of SCP T-South compared to Terasen Gas T-South of 497 TJ/d, where 113 / 497 = 20%. For 2002/03 the Terasen Gas share of the T-South and T-South/SCP revenue amounted to $609K while the SCP share amounted to $220K. These amounts and the percentage allocations were approved by the BCUC with the approval of the GSMIP 02/03.

7.4.2 Please identify any instances to date where there have been transfers of funds between commodity charge revenue accounts such as the MCRA and delivery charge revenue accounts that related to the use by Terasen Gas of Terasen Gas facilities.

Response:

The SCP mitigation revenue is allocated to the SCP deferral account based on a Commission pre-approved formula that reduces overall costs for all customers. This formula allocates revenue from the Midstream account to the Delivery Margin Account.

7.4.3 Please comment on the cost allocation implications of Terasen Gas' proposed accounting of the savings of $8 to $9 million per year from release of the Westcoast T-south capacity relative to the information provided in response to the preceding questions.

Response:

TGI is effectively utilizing SCP capacity rather than more costly Westcoast capacity in order to realize midstream cost savings.

The savings would be allocated to sales customers and the cost of foregone revenue ($3.6 million) would also be allocated to sales customers. By crediting the margin (Other Revenue – SCP) margin customers (sales and transport customers) would be held harmless. Terasen Gas recognizes that there is not a large number of precedents for the proposed treatment, however, the Company submits the proposed treatment provides, in this instance, a better matching of costs and benefits.

7.4.4 Further to the discussion on page 9, please provide a more detailed rationale for Terasen Gas' proposed approach in this context, expanding upon why Terasen Gas believes that the debiting of the $3.6 million against the MCRA with an equal and offsetting credit to delivery margin revenue is a fair and appropriate allocation.

Response:

Terasen Gas submits that the treatment of the lost PG&E revenue for the Interim Period as approved by the Commission is consistent with the treatment of the lost BC Hydro revenue in the Company's proposal in this application. In both instances the delivery margin revenue account is credited for the lost or "notional" revenue, thereby keeping delivery margin customers whole. With this treatment, the delivery margin revenue account is kept the same as it would have been had BC Hydro not exercised its Put Option. Based on these factors, the Company believes its proposal is fair and reasonable. This mirrors treatment that would be used if contracting firm transport service from any third party for the benefit of the Terasen Gas sales customers.

7.4.5 Please provide examples of other instances where the utility has utilized notional revenues and expenses for future test years that were a result of a cancelled contract from a customer.

Response:

The treatment of the 'notional" revenues with respect to the terminated PG&E transportation agreement during the Interim Period is an example where revenue recognized from a cancelled contract was credited to revenue. TGI is not aware of any other instance whereby "notional" revenues and expenses for future test years that were a result of a cancelled contract from a customer.

7.4.6 Please cite the CICA Handbook section that allows offsetting of revenues and expenses. Explain how the utility proposal meets the relevant section.

Response:

The CICA Handbook section that addresses the issue of offsetting of revenues and expenses is EIC-123. EIC-123 discusses the issue whether to report revenue gross or net for goods and services enterprises, which normally arises with enterprises that sell goods or services over the Internet. Many of those enterprises do not stock inventory and may arrange for third-party suppliers to drop-ship merchandise on their behalf. This is not applicable to our application.

The proposal is to offset the incremental benefits with a "demand charge" to reflect appropriate benefits in MCRA without impacting the delivery margin. MCRA is a regulated deferral account and the proposed treatment will ensure that the benefits on MCRA not overstated and minimize the rate impacts to customers.

The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers. In order to recognize the economic effects of regulation, GAAP for rate regulated enterprises allows the deferral of certain revenues and expenses in these operations.

7.4.7 Would the notional revenues and expenses be allowable taxable revenues and taxable deductions under the Income Tax Act?

<u>Response</u>:

No. The debit to MCRA would be added back to taxable income and the credit to margin would be a deduction to taxable income in the T2S (1). However, the net effect would be zero and would mirror to impact for calculation of taxes for regulatory purposes with the revenue requirement calculations.

7.5 Please compare the proposed accounting treatment for the loss of BC Hydro transportation revenue to the treatment of the revenue shortfall for the Interim Period, as it would appear that the net deficit in the SCP Deferral Account is being amortized to margin revenue requirements. To the extent that mitigation revenue during the Interim Period may have flowed through the MCRA to the SCP Deferral Account, please confirm that this mitigation revenue originated from third parties.

<u>Response</u>:

The mitigation revenue that was credited to the SCP Deferral originated from third parties and has been reported in the annual GSMIP filings since SCP went into service.

Terasen Gas submits that the treatment of the lost PG&E revenue for the Interim Period as approved by the Commission is consistent with the treatment of the lost BC Hydro revenue in the Company's proposal in this application. In both instances the delivery margin revenue account is credited for the lost or "notional" revenue, thereby keeping delivery margin customers whole.

7.6 Terasen Gas refers to the allocation of a portion of the net MCRA savings to delivery margin revenue. Most of the net MCRA savings are presented as resulting from the turn-back of Westcoast T-south capacity, and Westcoast toll charges have been paid through the MCRA (and previously through the Gas Cost Reconciliation Account ["GCRA"]) rather than through delivery margin revenue requirements. Please identify any portion of the BC Hydro transportation revenue that was allocated to the MCRA or GCRA to offset Westcoast T-south charges, and explain why any of the savings resulting from the termination of the 54.0 TJ/d of Westcoast service should be allocated to delivery margin revenue.

<u>Response</u>:

When BC Hydro exercised the "put option" in their contract for SCP capacity the capacity right and obligations were transferred to Terasen Inc. In assigning the capacity back to Terasen Gas Inc. from Terasen Inc. the utility is buying back the SCP capacity so that it can use the SCP capacity to enhance its midstream resources for the benefit of the core sales customers. The value of the SCP capacity that has been effectively repurchased is $3.6 million dollars that TGI would have received from Terasen Inc. and included in margin as Other Revenue related to SCP and allocated to margin customers. Recognizing the $3.6 million dollars with the equal offset to the MCRA is a way of compensating margin customers for the loss of SCP revenue that otherwise would have been there as an offset to the cost of service from Southern Crossing Pipeline.

Revenue received from BC Hydro with respect to its transportation agreement for SCP capacity has not been allocated to the MCRA and CCRA.

No savings resulting from the termination of the 54 TJ / day of Westcoast service is allocated to delivery margin revenue.

7.7 *Please explain the impact on sales customers, transportation customers and shareholders if the Commission does, or does not, approve the request regarding the allocation of the $3.6 million per year.*

<u>Response</u>:

As compared to the Company's proposal, if the request regarding the allocation of the $3.6 million is not approved transportation customers would have higher rates and correspondingly sales customers would have lower rates. The rate impact to transportation customers would be approximately 0.7% difference ($3.6million/$480 million, where expected gross margin equals approximately $480 million). Shareholders are indifferent as to whether the Commission approves or does not approve the request regarding the allocation.

7.8 *Please confirm whether it is Terasen Gas' intention that, at least from January 2006 onward, revenue from NW Natural will be recorded as delivery margin revenue. Please explain why this treatment of the increased revenue from NW Natural is consistent with the proposed allocation to the MCRA of the lost BC Hydro/Terasen Inc. revenue.*

<u>Response</u>:

The treatment of the NW Natural revenue as part of the delivery margin revenue is consistent with matching the allocation of the revenue to the allocation of the costs for the Southern Crossing Pipeline costs. NW Natural purchased and holds firm capacity on

Southern Crossing from Terasen Gas Inc. It is also consistent with the treatment of the revenue received from PG&E and BC Hydro.

Terasen Gas proposes to record the lost BC Hydro/Terasen Inc. revenue in a consistent fashion, i.e., a credit to delivery margin revenue. With this treatment, the delivery margin revenue account is kept the same as it would have been had BC Hydro not exercised its Put Option.

7.9 The Settlement that was approved by Commission Order No. G-74-00 allocated part of the peaking gas supply from BC Hydro and PG&E to transportation customers in the Interior. Please discuss whether an appropriate alternative to allocating an annual $3.6 million charge to the MCRA would be to provide transportation customers with a pro-rata share of the BC Hydro SCP capacity.

Response:

Section 5 of Rate Schedule 22A, and Section 10 of Rate Schedules 23 and 25 that covered SCP Peaking Gas allowed transport shippers to nominate peaking supply for up to 15 days through the winter. These sections in the tariffs did not contemplate 365 day capacity. Obligating industrial customers to take a pro-rata share of the SCP capacity would reduce the overall revenue allocated to the delivery margin given that the Midstream would not incorporate this resource in its portfolio. If any customer wanted, they could contract for SCP capacity.

7.10 At the Workshop on June 29, 2005, Terasen Gas seemed to indicate that, notwithstanding the termination of the PG&E and BC Hydro Peaking Agreements, it may be able to provide peaking service to transportation customers. Please explain how this would work and clarify whether it would only apply for transportation customers in the Interior.

Response:

Section 5 of Rate Schedule 22A, and Section 10 of Rate Schedules 23 and 25 cover SCP Peaking Gas and require Terasen to identify the “SCP Peaking Gas” available to each transport customer for the coming winter by the end of September each year. This “SCP Peaking Gas” is defined as “…the quantity of gas available to [Terasen Gas] in the Year commencing the next November 1 due to the operation of the Southern Crossing Pipeline.” Transport shippers can nominate this supply for up to 15 days through the winter. The Peaking Gas must be returned within 6 days of the day on which it was authorized.

If, as proposed, Terasen Gas is able to acquire the SCP capacity turned back by BC Hydro, and Terasen Gas plans its gas supply accordingly, then the effect would be to add the firm rights BC Hydro held to the peaking rights that the contract already entitled

Terasen Gas to use. Put another way, the new arrangement between Terasen Inc. and Terasen Gas would allow Terasen Gas to retain its 15 day peaking rights associated with the BC Hydro contract. Thus, Terasen Gas continues to have gas available to it due to the operation of Southern Crossing. Peaking Gas Services facilitated through the acquisition of the returned BC Hydro capacity would continue to be available to all non-bypass transportations customers under Rate Schedules 22A, 23 and 25.

This contrasts with the impact of the lost peaking rights due to the early termination of the PG&E contract and the subsequent contracting of the bulk of that capacity to Northwest Natural. In this circumstance, Terasen Gas lost its access to peaking capacity as well as supply.

7.11 Further to the response to the foregoing question, please provide an estimate of the amount of peaking supply that would be made available to transportation customers in the 2005/06 gas contract year, the expected source and cost of such peaking and how the peaking supply would be allocated among transportation customers.

Response:

Based on the current firm service held by industrial transport customers, the 2005/06 peak day volume available to transportation customers is expected to be 5.6 TJ/d or about 0.4% of the design peak day. The expected source and cost of the supply is based on Midstream resources available at the time the transportation customer elects the peaking supply. The transport customer can elect this peaking supply at any time during the winter months. The Midstream has had no issue in the past with managing this demand given the small volume.

This peaking arrangement requires that the transportation customer return the peaking supply within the 6 business days on which it was authorized. In the past years the portfolio costs have been indifferent to the election and return of the peaking supply. Peaking supply is allocated based on the formula outlined in Section 5.5 of Rate Schedule 22A, and Section 10.5 of Rate Schedule 23 and 25 of the Terasen Gas General Terms and Conditions as approved by the Commission. Since the "SCP Peaking Gas" used in the calculation is the quantity of peaking gas available to Terasen Gas due to the operation of Southern Crossing Pipeline, it can change from time to time as a result of changes to Terasen Gas' commitments to third parties using SCP.

7.12 The Settlement that was approved by Commission Order No. G-74-00 stated:

"The Parties agree that SCP costs are to be allocated to firm sales and transportation customers in proportion to the benefits received. In its Application, BC Gas proposed that all costs associated with SCP *cost* of service would be recovered through the delivery margin. The Parties recognize that the costs of all other BC Gas-owned transmission and peaking facilities are currently recovered in the delivery charge. There is no agreement as to whether this should continue following the full rate design for BC Gas that the Commission has directed to occur in 2001. However, until otherwise ordered by the Commission the Parties accept the recovery of the SCP cost of service through the BC Gas delivery margin."

The allocation of SCP costs does not appear to have been explicitly addressed in the 2001 Rate Design Settlement that was approved by Order No. G-116-01. Is Terasen Gas aware of any Commission determination that the SCP cost of service will be recovered in some way other than through Terasen Gas delivery charges? If so, please provide a copy of the determination.

Response:

No, Terasen Gas is not aware on any such determination. However, the proposal mirrors the effect of BC Hydro continuing to pay demand charges on SCP and we are preserving that same treatment. In effect, Midstream replaces BC Hydro as payor and delivery margin cost recovery of SCP is preserved.

7.13 Does Terasen Gas agree that the proposal to allocate $3.6 million per year of costs to the MCRA with an offsetting credit to the delivery margin account has the effect of allocating part of the SCP cost of service from delivery charges to the commodity charges? If Terasen Gas does not agree, please explain.

Response:

No, Terasen Gas does not agree. Currently the $3.6 million of demand charges from BC Hydro related to the TSA are applied to the delivery margin account and also have the effect of partially offsetting the SCP cost of service from delivery charges. The proposal to allocate $3.6 million from MCRA to the delivery margin account effectively replaces the BC Hydro revenues. This has the same effect as if Terasen Inc or BC Hydro continued to hold the SCP TSA and Terasen Gas contracted for the capacity as part of the midstream portfolio. In other words, the $3.6 million demand charges due under TSA would be credited against the delivery margin while the Midstream would pay $3.6 million to the holder of the TSA.

On the MCRA side, commodity charges currently include the cost of holding other resources that are avoided when the SCP capacity is incorporated. The proposal contemplated by the Application effectively has MCRA contracting for SCP capacity from the delivery margin account, and making other adjustments to its portfolio that result in net savings and lower commodity or midstream charges as applicable.

7.14 Please explain why Terasen Gas believes that the current application and written hearing is the appropriate forum for the Commission to consider the allocation of costs between MCRA and delivery margin account, rather than a rate design proceeding for example.

Response:

A rate design proceeding is a more comprehensive review of the fairness of the rates the company charges to recover its cost of service and review of the General Terms and Conditions.

The allocation of costs between MCRA and delivery margin as proposed in this application is in reaction to BC Hydro exercising its Put Option which is a very narrow focused issue where the potential benefits are not insignificant. Terasen Gas is of the opinion that this specific issue is not sufficient in of itself to warrant a rate design proceeding, and submits that because customers will realize substantial benefits as a result of Terasen Gas utilizing the SCP capacity, it is not unreasonable to deal with this cost allocation issue outside of a rate design proceeding. Additionally, the Intervenors participating in this proceeding largely represent customers who would likely be participating in a rate design proceeding.

7.15 On page 7 of the Application, Terasen Gas refers to certain priority rights that BC Hydro received under its TSA. Please clarify the value or cost of such rights that Terasen Gas identified at the time it filed the BC Hydro TSA for Commission approval. Should the Commission assign a greater value to these rights with respect to the termination of the BC Hydro agreements?

Response:

The rights described were all part of the terms and conditions of the TSA that was reviewed and approved by the Commission. Pursuant to Article 7, the value of these rights would have accrued to BC Hydro if and when Terasen Gas capacity to move gas from Oliver to the lower mainland of British Columbia was increased directly or indirectly beyond what is available when SCP was commissioned and/or as a result of an expansion of SCP. The rights under this clause would not have impacted the value of SCP third party capacity to Terasen Gas and therefore were not quantified at the time the BC Hydro TSA was filed. Similarly there is no cost to Terasen Gas associated with the termination of the BC Hydro agreements. It is simply a lost opportunity for BC Hydro as a consequence of its decision to exercise the Put Option.

Inland Pacific Connector ("IPC")

8.0 Reference: Exhibit B-1, pp. 10-12; Attachments 4, 5
IPC Development Costs

8.1 The Application at page 12 refers to IPC development costs of $5.4 million plus AFUDC of $392,000, and at page 4 states these costs are currently included in a non-utility deferral account.

8.1.1 Please clarify whether the IPC was developed as a project of Terasen Gas, Terasen Inc. or some other corporate entity. If ownership of the project changed, please identify when and why.

Response:

The IPC was being developed as a Terasen asset, however a decision on the final ownership structure had not made at the time the development activities were taking place. Terasen Gas is a 100% wholly owned subsidiary of Terasen Inc, therefore from Terasen's stand point there is no effective difference whether the development costs were recorded as a non-regulated deferral account of Terasen Gas or by Terasen Inc. If IPC had proceeded, the final ownership structure of the project and the tolling associated with transportation service would had been determined at the time of filing of the CPCN for review and approval.

All costs associated with the project, including an appropriate allocation of time associated with internal Terasen Gas employees, were being tracked in a non-rate base deferral account and have not been included in revenue requirement for recovery through customer rates. From this viewpoint it was the shareholders of Terasen Inc that were exposed to the development costs if the project did not proceed and it could not be demonstrated that IPC development activities delivered value to Terasen Gas customers that would not otherwise have been realised. In this Application, Terasen Gas is now seeking to recover the development costs on the basis that the development of IPC has delivered significant value to Customers.

8.1.2 Please identify and quantify any actual or planned payments to be received by Terasen Inc. related to the IPC project.

Response:

No payments have been received by Terasen Inc or by Terasen Gas related to the IPC project.

8.1.3 Please provide the business case and/or project justification for the IPC development costs that was presented to the Board of Directors and/or senior management meeting(s).

Response:

Please see Appendix C. The justification for IPC was based on a market assessment that concluded that new transmission capacity would be needed to meet the growing demand for gas in the BC and Pacific Northwest region, particularly for power generation. It was felt that the significant disconnection of local gas markets in November 2000 through January 2001 had a considerable impact on gas costs for customers and was a clear sign of the need for this new capacity.

Terasen believed that IPC could be a viable alternative to providing new regional capacity. In addition, it was believed that Terasen Gas inc. customers would benefit from the development of IPC, both directly by providing a means to reduce the cost of service of SCP to customers and indirectly by providing more capacity into the region enhancing the security and diversity of supply. It was intended that the project would be regulated by the BCUC and that the transmission service would be based on cost of service tolling. Terasen's senior management understood that the project would proceed only if Terasen could demonstrate that IPC was a viable alternative and solidified market support through firm shipper commitments.

In order to position IPC as a viable alternative to meeting the need for new regional capacity, and to obtain shipper support, Terasen undertook to commence routing, preliminary design, land use, and environmental assessment activities. Please refer to Appendix C for a copy of the presentation material presented to senior management that supported the market assessment and the development of IPC.

It should be noted that following the extreme volatility of natural gas commodity prices in the winter 2000/01, the Commission also sought to understand the market fundamentals affecting the Sumas market place. In Letter L-13-01 dated March 15, 2001, the Commission summarised the input received from various industry participants that generally concluded that price disconnects had resulted from constrained capacity to serve the Sumas market. In the letter, the BCUC also requested that Terasen Gas provide a regional resource report that included input from various regional stakeholders. Terasen Gas filed the Regional Resource Planning Study in July 2001. Copies of Commission Letter L-13-01 and the abstract of Terasen Gas's study can be found in Appendix C.

8.1.4 Please describe the management approvals necessary to authorize spending for IPC development costs.

Response:

The management approvals for development costs were staged over time as was seen to be necessary to maintain the project as a viable and competitive alternative for new capacity in the region. The initial approvals were obtained prior to the institution of the current Capital & Process Steering Committee and the Capital Allocation Committee structures, however similar processes were followed. The following summarises the approvals that were obtained to support the development work:

February 2001: The BC Gas Inc executive committee approved the spending of up to $2.0 million to support preliminary development work. This represented the maximum authorisation permitted at the time prior to requesting approval from the Board of Directors.

June 2001: Terasen Inc Board of Directors approved spending of up to $4.0 million to support IPC development costs to the end of 2001.

May 2002: Terasen Inc. approved an additional spending of up to $1.6 million taking the total spending authorisation to $5.6 million. The approval for this spending was to allow completion of the first phase of the environmental assessment process and capture the full value of the development activities to date.

8.1.5 Who was the executive sponsor? Please provide the name, title/position, and company.

Response:

Prior to December 2001	Rich Ballantyne Director, Transmission Planning BC Gas Utility Ltd (Currently President, Terasen Pipelines Inc.)
December 2001 to Present	Douglas L. Stout Vice-President, Gas Supply & Transmission (to Jan 05) Vice-President, Marketing and Business Development (current position) Terasen Gas Inc.

8.1.6 What was the total budgeted or anticipated cost for the completed IPC project?

Response:

The IPC project consisted of an expansion of SCP through the addition of 3 new compressor stations and upgrades at Kitchener and a new 246 km pipeline from Oliver to Huntingdon via Hope. In addition, a lower cost option was also explored where the new pipeline terminated at Hope and connected with Westcoast system for transport to Huntingdon. This lower cost option would have been pursued if an agreement could have been reached with Westcoast for transport service from Hope to Huntingdon that would have reduced the overall transportation cost from Yahk to Huntingdon, or allowed the project to proceed with lower volume of shipper commitments.

The cost breakdown is as follows:

Option	IPC Pipe		SCP Compression		Total
	Km	M$	kHp	M$	M$
Oliver to Huntingdon	246	370	48	125	495
Oliver to Hope	154	235	27	62	297

8.2 Please identify which account(s) including account name(s) and which company the $5.4 million of IPC development costs is carried in.

Response:

The IPC Development cost of $5.4 million is carried in the Terasen Gas Inc. accounting records under Preliminary Survey and Investigation Charges. This account has not been attracting any interest charges and has not been included in the Company's rate base for the purposes of rate-setting.

8.3 Enclosed is page 61.6 from the Terasen Gas Inc. 2003 Annual Report to the Commission. Line 9 indicates "Non-Utility Portion of Preliminary Surveys", Account 172, of $5.63 million. Were the IPC development costs included in this total? If yes, provide the total amount of the IPC development costs included in the $5.63 million.

Response:

IPC development costs in the amount of $5.38 million were included in the $5.63 million total shown on Page 61.6, Line 9, of the Terasen Gas Inc. 2003 Annual Report to the Commission.

9.0 Reference: Exhibit B-1, pp. 2, 12
IPC Open Season

9.1 The Application at page 2 states that in May 2001, Terasen Gas held an Open Season for capacity on the IPC. Please confirm whether it was BC Gas Inc. (now Terasen Inc.) and not BC Gas Utility Ltd. (now Terasen Gas) that held the Open Season. If confirmed, why did BC Gas Inc. hold the Open Season?

Response:

The Open Season was held by Terasen Inc. As indicated in the response to 8.1.1, the final ownership of IPC was to be determined once the project had sufficient support to proceed. As Terasen Gas is a 100% owned subsidiary of Terasen Inc, it was felt that holding the Open Season in Terasen Inc.'s name gave the most flexibility for future ownership structure decisions.

9.2 Please provide the Open Season documents provided to the prospective bidders. Also, please provide copies of all the commitments received in response to the Open Season.

Response:

The Open Season documents are attached to this information response. These documents were available to any interested party during the IPC Open Season, and were provided to the BCUC under cover letter dated May 4, 2001. Please refer to Appendix D.

The responses received from prospective shippers were received confidentially and therefore have not been attached. However, a summary of the shipper responses received during the Open Season period is provided in the following table. As is noted, BC Gas Utility, now Terasen Gas Inc., was one of the parties that responded to the open season. BC Gas Utility made a firm request for 50 mmcfd of capacity, plus indicated that it was prepared to contract for an additional 50 mmcfd, pending BCUC approval, if the additional capacity allowed the project to proceed. Shippers 2 and 3 both had placed additional conditions on their responses.

RESPONSE	Quantity	Conditional Quantity
Shipper 1	44.5 MMcfd	
Shipper 2		52.5 MMcfd
Shipper 3		40.0 MMcfd
Shipper 4 (BC Gas Utility)	50.0 MMcfd	
Shipper 5 (BC Gas Utility)		50.0 MMcfd

Subtotal	95.4 MMcfd	142.5MMcfd
Total	94.5 to 237.0 MMcfd	

9.3 Please explain how Terasen Inc. intended to obtain service on SCP and perhaps other Terasen Gas facilities in order to fulfill its Open Season offer to move gas from Yahk to Huntingdon.

Response:

If IPC had been owned by a separate Terasen entity, an agreement would have been put in place between the IPC entity and Terasen Gas for transportation capacity across SCP. In turn, the IPC entity would use its SCP capacity to provide the full transportation path from Yahk to Huntingdon. At the time the project was being developed, it was Terasen's view that market and competitive positions would make it necessary to set IPC transportation tolls based on the incremental costs of the new facilities on SCP. However, a key principle guiding the design of the project and tolling was that IPC would have a positive impact on the SCP cost of service and additional measures would be put in place to deliver incremental benefits for the existing SCP customers.

9.4 Did Terasen Inc. intend that IPC would be regulated by the Commission, the National Energy Board or would be an un-regulated facility?

Response:

It was expected that the IPC would be regulated by the British Columbia Utilities Commission.

9.5 On page 11 the Application states: "Terasen Gas also believes that the development of a legitimate pipeline alternative to serve the region has resulted in a better positioning for the Terasen Gas and other regional location distribution companies in the dealings with Westcoast Energy…" In addition the Terasen Gas states: "…the development of IPC prompted Westcoast to respond with its own expansion project, which in turn leads to the successful negotiation of the Kingsvale South tolls with Westcoast in 2002."

9.5.1 Please provide a timeline of events with specific dates for key milestones for SCP and IPC, including a brief description where applicable.

Response:

May 30, 1997	BC Gas Utility files SCP CPCN Application
April 3, 1998	BCUC issues decision denying SCP Application
July 14, 1998	BC Gas files NEB Application for orders to have Westcoast establish a new receipt point at Kingsvale and set volume distance-based tolls for Kingsvale South service
Dec 11, 1998	BC Gas Utility files amended SCP CPCN Application
Mar 26, 1999	NEB Decision RH-2-98 directs Westcoast to have new receipt point at Kingsvale for delivery at Huntingdon. Kingsvale south toll is set at the equivalent of long haul T-South
May 20, 1999	Environmental Assessment Office issues SCP Project Approval Certificate
May 21, 1999	BCUC issues decision granting SCP CPCN Application
June, 1999	SCP construction begins
Dec 1, 2001	SCP complete and put in-service
April 19, 2001	Westcoast announces Open Season for T-South
May 7, 2001	IPC Open Season
May 8, 2001	BC Gas Utility files NEB application for review and variance of the Board's RH-2-98 Reasons for Decision and for setting of tolls for Kingsvale South service.
November 2001	NEB Decision RH-2-2001setting out that: • if Westcoast expands its system between Kingsvale and Huntingdon to provide service to BC Gas between these two points, the difference between the Station 2 to Huntingdon toll and the Inland Delivery toll will apply to Kingsvale south deliveries; and • that until the Westcoast system is expanded, the toll for firm deliveries from Kingsvale to Huntingdon will remain the full Zone 4 toll (Station 2 to Huntingdon);
April 23, 2002	Westcoast advises NEB that it has reached an agreement with BC Gas, and indicates that a revision to its facilities application is forthcoming.

May 15, 2002	WEI files with NEB an application to reduce the size of the WEI Expansion, allow BC Gas to segment 105 mmcf/d into 105 Mmcf/d of Kingsvale south capacity and 50 mmcf/d of IDA Capacity.
May 20, 2002	BC Gas files application for EAO Project Approval Certificate for Inland Pacific Connect.
October 2002	WEI announces that there was turnback of T-South capacity effective November 1, 2003.
April 2003	WEI does its final realignment of expansion to take into account November 1, 2003 turnback and 2 year agreement with Portland General Electric for 20 mmcf/d.
October 2003	WEI announces that about 200 mmcf/d of T-South capacity was not renewed effective November 1, 2004.
October 2004	WEI announces that about 38% of T-South Huntingdon capacity is not contracted effective November 1, 2005.

9.5.2 Please provide the timeline of events with specific dates for the IPC Open Season and the Westcoast Open Season. Include a description, where applicable.

Response:

Inland Pacific Connector

May 7, 2001	Open Season Began
June 7, 2001	Open Season Closed
November 1, 2003	Target In-service date

Westcoast Southern Mainland Open Season

April 19, 2001	Open Season announced
May 31, 2001	Open Season closed
November1, 2003	Target In-service date
May 15, 2002	WEI reconfigures expansion to take into account segmentation of 105 Mmcf/d of BC Gas T-South capacity, reducing size of expansion by About 35 km of looping
October 2002	WEI announces non-renewal of T-South capacity effective November 1, 2003
April 2003	Final expansion configuration includes no looping
October 2003	WEI announces non-renewal of about 200 mmcf/d of T-South capacity Effective November 1, 2004.
October 2004	WEI announces additional non-renewal of T-South capacity such that About 38% is un-contracted to Huntingdon effective November 1, 2005.

9.5.3 If the Kingsvale South toll negotiations were not successful, what would have been the National Energy Board process to achieve segmented tolls? Please elaborate.

Response:

If Terasen had been unsuccessful in negotiating segmented tolls through negotiation, it would most likely have put argument to the National Energy Board against Westcoast's expansion. The argument would have followed the lines of Terasen Gas' letter of intervention to the Board in early 2002, prior to the Westcoast hearing in September-October 2002, that in not addressing the issue of capacity segmentation prior to the expansion, Westcoast was, in effect, requesting the construction of more capacity than was necessary, and that the market overall would be better served with a reduced build. Acceptance by the NEB of Terasen Gas' position, without an agreement from Westcoast, would likely have resulted in a denial of Westcoast's application, or conditional approval with instructions to file segmented rates prior to final construction approvals. Either of these outcomes would have resulted in delays, and could have led to several possible scenarios with plans and contracts subject to regulatory outs.

Alternatively, the NEB could have approved Westcoast's expansion, leaving the issue of segmented tolls for a future rate application. Under this scenario, segmented tolls would again be far from certain, as Westcoast would likely have argued that such toll treatment would still result in system off-loading because Terasen did not turn back capacity during the expansion process, given the potential prospect of paying full T-South tolls for Kingsvale to Huntingdon service. Terasen would have been in a "catch 22" of having to either assume that it could secure savings in the future if it reduced its requirements on the Westcoast system prior to the expansion, or hope that the NEB would see things differently than it had in two previous regulatory proceedings through which Terasen had been denied toll segmentation. Of course, there was the possibility that if the IPC project was completed, Terasen Gas could have broken its reliance on Westcoast, which depending on the sequence of events might have resulted in pipe capacity proceeding in advance of the market overall.

What is clear, is that without some sort of negotiated agreement, the regulatory and market outcomes and timing were in no way certain, and the probability of some lost value to Terasen Gas' customers and the market overall was high.

10.0 Reference: Exhibit B-1, p. 12, Exhibit B-2, pp. 2 and 8
IPC Development Costs as Rate Base

In Exhibit B-2, p. 2, item 7 states: "With the transfer of NWN from being an anchor tenant on IPC to contracting for existing SCP capacity, BCGUL shareholders are now at increased risk that IPC will be further deferred or cancelled."

In Exhibit B-2, p. 8, item 6 states: "BCGUL customers will realize very significant long term financial benefits over the projected benefits of the existing SCP arrangements."

In Exhibit B-1, p. 3, item 11 states: "Terasen Gas recognises (sic) that market conditions supporting new pipeline capacity in the region have changed significantly since 2002, and now expects the IPC project to be substantially deferred."

Exhibit B-1 at page 12 states: "Terasen Gas submits that it is reasonable and fair to customers to recover the IPC development costs, including AFUDC, by placing the costs into the SCP rate base and recovering the costs through the delivery charge, and requests approval of these transactions as described, effective January 1, 2006."

Exhibit B-1 at page 12 states: "Development of IPC has increased the value of the SCP transportation for Terasen Gas. The project is effectively an expansion and extension of the SCP, and because it has added value to SCP, the company proposes that the IPC development costs be included as part of the SCP rate base."

10.1 Please explain if the Canadian Institute of Chartered Accountants Handbook ("Handbook") Section 3450 Research and Development Costs apply to the IPC development costs. If so please explain why the IPC development costs qualify for deferral to future periods rather than a charge to expense in the current period. If Handbook Section 3450 does not apply to the IPC development costs, please explain why not. Please provide a copy of Handbook Section 3450-Research and Development Costs.

<u>**Response**</u>**:**

The definitions for research and development costs per CICA Handbook section 3450 are:

> **Research** is planned investigation undertaken with the hope of gaining new scientific or technical knowledge and understanding. Such investigation may or may not be directed towards a specific practical aim or application.
>
> **Development** is the translation of research findings or other knowledge into a plan or design for new or substantially improved materials, devices, products, processes, systems or services prior to the commencement of commercial production or use.

According to the CICA 3450, research is defined as “a planned investigation undertaken with the hope of gaining new scientific or technical knowledge and understanding. Such investigation may or may not be directed towards a specific practical aim or application”; and development is defined as “the translation of research findings or other knowledge into a plan or design for new or substantially improved materials, devices, products, processes, systems or services prior to the commencement of commercial production or use.” IPC development costs incurred to date are preliminary studies and design of an asset base expansion project which will generate additional benefits to the various stakeholders. The costs are currently reported as a deferred charge which will benefit future periods. Upon completion of the project, the development costs will be transferred to capital assets and will form part of the costs of the IPC connector. The CICA section 1000 allows for deferral of these costs as an asset if they contribute directly or indirectly to the future net cash flow of the organization.

To view Section 3450 of the CICA Handbook, refer to Appendix E. To view Section 1000 of the CICA Handbook, refer to Appendix F.

10.2 If the Commission does not approve the recording of the IPC development costs in Terasen Gas’ utility accounts, what accounting treatment would result for the IPC development costs?

Response:

In Terasen Gas Inc.’s financial statements IPC development cost are reported as deferred charges on the basis that the costs incurred to date will benefit future periods and are expected to be capitalized on completion of the project. If the project is abandoned then the costs would be required to be written off during the period when the project was abandoned. The deferred charges are assessed quarterly to ensure the continued validity of reporting them on the balance sheet.

10.3 Please explain why the IPC development costs have the three essential characteristics of an asset in accordance with Handbook Section 1000.30 and do not meet the recognition criteria of expenses under Handbook Section 1000.50. Please provide a copy of Handbook Section 1000 - Financial Statement Concepts.

Response:

According to Section 1000.30

Assets have three essential characteristics:

(a) they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

(b) the entity can control access to the benefit; and

(c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

CICA section 1000.30 is a broad definition of an asset which should have three distinct characteristics. An asset needs to provide future benefit by ultimately providing incremental net cash flow to an organization. The costs incurred to date for the development of the IPC connector will ultimately provide incremental cash flow to the organization and customers once the project is complete. The company controls the access to these benefits and the transaction has occurred in the past so the last two criteria have been met.

To view Section 1000 of the CICA Handbook, refer to Appendix F

10.4 Please explain why the IPC development costs meet the definition of "cost" under Handbook Section 3061.05. Please explain Terasen Inc. and Terasen Gas' estimate of the useful life of IPC development costs in terms of its physical, technological, commercial and legal life under Handbook Section 3061.29. Please provide a copy of Handbook Section 3061 - Property Plant and Equipment.

Response:

Currently, the IPC development costs are not capitalized under CICA 3061.05 but are capitalized using the definition of assets in CICA Section 1000 as presented above. On completion of the connector, these costs will meet the definition of 3061.05. All amortization and depreciation taken on regulatory assets is done in accordance with the BCUC set rates for individual asset classes. The estimated useful life of assets is determined via regulatory studies on depreciation rates for all regulatory assets.

To view Section 3061 of the CICA Handbook, refer to Appendix G

10.5 Please explain why Terasen Gas considers that the IPC development costs meet the definition of "fair value" under Handbook Section 3063.03(b). Please provide a copy of Handbook Section 3063.

Response:

The IPC development costs incurred to date represent amounts paid to arms length parties. As the amounts have been paid to third parties, the amounts are considered to be at fair value.

To view Section 3063 of the CICA Handbook, refer to Appendix H

10.6 Please provide a copy of the following account descriptions from the Uniform System of Accounts for Gas Utilities:

- *Account 100-Gas Plant in Service*
- *Account 102-Gas Plant Held for Future Use*
- *Account 110-Other Plant*
- *Account 172-Preliminary Survey and Investigation Costs*

Response:

Account 100 – Gas Plant in Service
This account shall include the investment in plant, property and equipment (including that held under contract for purchase), in service at the date of the balance sheet.

This account shall also include the cost of improvements made to leased facilities, where such improvements are used in gas service and the company is not to be reimbursed by the lessor for such improvements.

When the cost of improvements made by the company is to be refunded by the lessor, the company pending settlement with the lessor shall include the cost of such improvements in this account.

When plant (including leased facilities) is retired from service, this account shall be credited with the ledger value of the plant retired and a like amount shall be concurrently charge to account No. 103, “Retirement Work in Progress”. (See general instructions, section 8).

The plant included in this account shall be classified according to the detailed accounts for such plant. The cost of improvements to leased facilities shall be maintained in the subdivision separate from those relating to owned plant.
Note A- Improvements to facilities leased on a short term basis shall be included in account No.179, “Other Deferred Charges”.

Account 102 – Gas Plant Held for Future Use
This account shall include the cost of plant owned and held for future use in gas service. There shall be included herein plant acquired but never used by the utility in gas service, but held for such service in future, and plan previously used by the utility in gas service, but retired from such service and held pending its re-use in the future in gas service. This includes land and land rights held to insure a future supply of natural gas.
The plant included in this account shall be classified according to the detailed accounts prescribed for gas plant in service and the account shall be maintained in such detail as though the plant were in service. Separate sub-accounts shall be maintained hereunder for each department for which plant is held for future use.
Note A – Material and supplies, meters and house regulators held in reserve, and normal spare capacity of plant in service shall be included in account No. 150, “Material and Supplies – Gas”.

Note B – Include in this account natural gas wells shut in after construction which have not been connected with the line; also, natural gas wells which have been connected with the line but which are shut in for any reason excepting seasonal excess capacity or government proration requirements or for repairs.

<u>Account 110 – Other Plant</u>
This account shall include the cost of land, structures, equipment or other tangible or intangible plant owned by the utility, but not used in gas service and not properly includible in account Nos. 101, “Gas Plant Leased to Others”, 102, “Gas Plant Held for future Use” or 115, “Gas Plant Under Construction”.

This account shall be subdivided so as to show the amount of plant used in operations which are non-utility in character but nevertheless constitute a distinct operating activity of the company and the amount of miscellaneous plant not used in operations. The records in support of each sub-account shall be maintained so as to show an appropriate classification of the plant.

<u>Account 172 – Preliminary Survey and Investigation Charges</u>
This account shall include all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of projects for gas services. If, as a result of the surveys, plant for gas services is acquired or constructed this account shall be credited and the appropriate gas plant account charged. If the work is abandoned, the charge shall be to account No. 329, “Other Income Deductions”, or if the amount is material, to account No. 332, “Extraordinary Deductions”.

The record supporting the entries to this account shall be so kept that the company can furnish complete information as to the nature and purpose of the survey, plans or investigations, and the nature and respective amounts to the charges.

10.6.1 Please explain why the IPC development costs, if they are to be recorded in the utility accounts, should not be recorded in a non-rate base deferral account. If the Commission was to decide that deferral account treatment was appropriate for the IPC development costs, what amortization period would Terasen Gas propose?

<u>Response</u>:

Terasen Gas does not believe the IPC development costs should be afforded non-rate base treatment since it believes it has now demonstrated that development of the project has created benefits for customers and has enhanced the value of SCP. TGI’s proposed treatment is consistent with how Terasen Gas accounts for the SCP costs.

If the IPC development costs were to be amortized rather than included in SCP rate base, Terasen Gas would propose they be recorded as a rate base deferral account and amortized over a period of 5 years, consistent with other approved SCP deferral accounts.

10.6.2 Please explain why the IPC development costs should not be recorded under Account 172-Preliminary Survey and Investigation Costs. Please explain if having the IPC project as "substantially deferred" is equivalent to being abandoned as defined in Account 172.

Response:

The cost could be recorded as preliminary survey and investigation cost. The risk is that because the project is substantially deferred, there is greater uncertainty if the project will go ahead and depending on the length of the delay, how relevant the current costs incurred will be to the eventual project.

10.6.3 Please provide a schedule that shows the currently approved depreciation and amortization rates for Accounts 100, 102, 110 and 172 broken out by the supporting detailed accounts.

Response:

This table shows the depreciation rates for Accounts 100, 102 and 110. No depreciation is calculated on account 172.

Asset Class	Description	Rate	Asset Class	Description	Rate
Account 100 Gas Plant in Service					
40100	Franchises and Consents	1.00%	47300	DS Services	2.00%
40200	Intangible Plant	1.00%	47400	DS Meters/Reg. Installation	3.57%
40210	Plant Acquisition Adjustments	1.00%	47500	DS Mains	2.00%
43000	Mfg. Gas Plant Land	0.00%	47600	DS NGV Fuelling Equipment	6.67%
43200	Mfg. Gas Plant Structures and Improvement	1.50%	47710	DS Meas./Reg. Stn Additions	3.00%
43300	Mfg. Gas Plant Equipment	3.00%	47720	DS Telemetry	10.00%
43400	Mfg. Gas Plant Holders	2.00%	47730	DS Meas./Reg. Equipment- Byron Creek	5.00%
43600	Mfg. Gas Plant Compressor Equipment	3.00%	47810	DS Meters	3.57%
43700	Mfg. Gas Plant Meas/Reg. Equipment	3.00%	47820	DS Instruments	3.57%
44000	LNG Gas Plant Land	0.00%	47900	DS Other Plant	4.00%
44200	LNG Gas Plant Structures and Improvement	4.00%	48000	GP Land	0.00%
44300	LNG Gas Plant Equipment	4.00%	48210	GP (Frame) Structures and Improvements	3.00%
44900	LNG Gas Plant Other Equipment	4.00%	48220	GP (Masonry) Structuresand Improvemen	1.50%
46000	TP Land	0.00%	48230	GP (Leased) Structures and Improvement	lease term
46100	TP Land Rights	0.00%	48310	GP Computer Hardware	20.00%
46110	TP Land Rights - Byron Creek	5.00%	48320	GP Computer Software (infrastructure)	12.50%
46200	TP Compressor Structures and Improvemen	3.00%	48320	GP Computer Software (non-infrastructure	20.00%
46300	TP Meas/Reg. Structuresand Improvement	3.00%	48330	GP Office Equipment	5.00%
46400	TP Other Structures andImprovements	3.00%	48340	GP Office Furniture	5.00%
46500	TP Pipelines	2.00%	48400	GP Company Owned Vehicles	15.00%
46510	TP Pipelines - Byron Creek	5.00%	48510	GP Heavy Work Equipment	5.00%
46600	TP Compressor Equipment	3.00%	48520	GP Heavy Mobile Work Equipment	5.00%
46710	TP Meas/Reg. Equipment	3.00%	48600	GP Small Tools and Equipment	5.00%
46720	TP Telemetry Equipment	10.00%	48720	GP NGV Cylinders	10.00%
46800	TP Communications Structures and Equipm	10.00%	48730	GP Vehicle Refuelling App.	33.30%
47000	DS Land	0.00%	48810	GP Communication Telephone Equipmen	5.00%
47100	DS Land Rights	0.00%	48820	GP Communication Radio Equipment	10.00%
47110	DS Land Rights - Byron Creek	5.00%	48900	GP NRB Disc Depn	0.00%
47200	DS Structures and Improvements	3.00%	49800	Overhead Charged to Construction	2.20%
47210	DS Structures and Improvements - Byron	5.00%			

Asset Class	Description	Rate	Asset Class	Description	Rate
Account 102 Gas Plant Held for Future Use					
49210	Plant Held for Future Use Not Depreciabl	0.00%	49230	Plant Held For Future Use Depreciable (	5.00%
49220	Plant Held For Future Use Depreciable @	3.00%			
Account 110 Other Plant					
49010	NRB Not Depreciable	0.00%	49040	NRB Depreciable @ 9.4%	9.40%
49020	NRB Depreciablble @ 2.4%PA	2.40%	49050	NRB Depreciable @ 2% PA	2.00%
49030	NRB Depreciable @ 5% PA	5.00%			

10.7 Enclosed are excerpts from Bonbright's Principles of Public Utility Rates ("Bonbright"). Pages 259-260 address the Accounting for Abandonments and Disallowances of Plant Costs and pages 291-292 address Allowing the Recovery of Cost for Abandoned Investment. Bonbright on page 291 considers that the investor and ratepayer should be equal risk takers and that aborted projects should be included in cost of service but that ratepayers are only required to pay a return on only those investments in properties that are used and useful in the public service.

Please explain why Terasen Gas considers that the ratepayer should pay and the shareholder should receive a return on the IPC development costs, in addition to the recovery of the IPC development costs. Please explain why Terasen Gas considers that the IPC development costs are used and useful in the public service.

Response:

Bonbright on page 292 states the following regarding the "prudent investment" test is:

> *"The commission should apply the "prudent investment" test, which provides that a utility and its investors be permitted to earn on capital prudently invested for the purpose of providing service – regardless of whether the investment turns out to be successful. Because construction of facilities occurs over several years, conditions change which on a hindsight basis would mean that the utility might not construct the facility. However, along the way, prudent decisions, based on the information at hand were made. Investors should NOT be penalized for those prudent decisions should the conditions change which cause the project to be cancelled."*

Terasen Gas submits that the planning and development of the IPC was a prudent decision and that the costs incurred were prudently invested for the purpose of providing service. Moreover, in light of the fact that Terasen was able to secure Northwest Natural as an SCP shipper to replace PG&E at a premium by virtue of NWN's commitment on IPC, it is evident that customers of TGI have benefited from IPC development expenditures and will continue to for at least the remainder of the NWN Transport agreement. Accordingly, because the project is not moving forward, shareholders in the Company should not be penalized. Additionally, as stated in the Application, Terasen Gas believes that "…the agreement with NWN, along with the significant revenues would not likely have been realized if the IPC project had not been under development." Based on these factors the Company submits the IPC development costs are used and useful in the public service.

10.8 Bonbright on page 292 describes the "prudent investment" test which provides that a utility and its investors be permitted to earn on capital prudently invested for the purpose of providing service-regardless of whether the investment turns out to be successful. The goal is described as encouraging economically efficient decisions such as starting a new plant or abandoning a plant now in progress. Please explain how Terasen Inc. and Terasen Gas applied the prudent investment test on the IPC development project in regards to the following:

10.8.1 In Terasen Gas' 2004-2007 Multi-Year Performance Based Rate ("PBR") Plan Application, page D-2 there is a discussion of CPCN applications under the 1998-2001 PBR Plan which states: "Large capital projects, typically those that exceed $5 million, are approved by the Commission through the issuance of a CPCN." If the IPC was intended to be a utility project, why was not a CPCN application filed by Terasen Gas?

Response:

Terasen Gas submits that its investment made in the planning and development of the IPC project was prudently invested for the purpose of providing service. As stated in its Response to IR # 9.4, the Company anticipated that a CPCN Application would be necessary before construction of the project commenced.

10.8.2 If it was Terasen Gas' intention to apply for cost-recovery of the IPC development costs when was the decision for substantial deferral or abandonment of the project made?

Response:

The December 5, 2002 Application (Exhibit B-3) stated that it was Terasen's intent to begin recovery of IPC costs in 2006 if the project had not proceeded (paragraph 7 of Executive Summary and Section 5). The target in-service date at the time was November 2005 however without NWN as an anchor tenant it was expected that this would be deferred at least to November 2006. In Commission Letter No. L-48-02, the Commission indicated that it was prepared to review a future application for recovery of the IPC expenditures if the project is deferred substantially based on the value delivered by IPC including the NWN arrangements.

If the project was to proceed, it would require one more summer window for the detailed environmental and routing work to complete the final phase of the Environmental Assessment Office process, and then two construction seasons. As a result, it is felt that the earliest practical project schedule would require shipper commitments 30 months prior to a target November start-up date. In order to support a November 2006 in-service date, therefore, shipper commitments and a decision to proceed with the next phase of development would have been required by May 2004. At that time, Terasen concluded that market conditions would not support that timetable, and the project was again deferred. It is now expected that the Pacific Northwest market will not support new pipeline capacity until near the end of the decade, therefore Terasen now believes the project will be substantially deferred.

10.8.3 Attachment 5 shows additions to the IPC development costs up to July 2004. Commission Letter No. L-48-02 refers to the December 5, 2002 Application. Why did spending on the IPC project continue after the filing of the December 5, 2002 Application?

Response:

At the time of the 2002 Application, spent and committed IPC development costs amounted to approximately $5 million, largely for design, routing and environmental activities required to support the environmental review process. At the time it was expected that there would be approximately $600,000 of spending required by April 2003 to complete phase of the Environmental Review that was on going at the time and set out the process for obtaining the final approvals for the Environmental Assessment Office. Completing that phase of development was necessary to ensure maximum value from the work that had been completed to date. Suspending activities at that point would have meant that EAO review and stakeholder consultation process would have been terminated before any conclusions had been reached, and the process would have had to start anew if the project was to become viable again.

Since mid 2003, however, IPC development activities have largely been suspended. Expenditures shown on Attachment 5 between March and June 2003 were largely for work that had been performed to support the EAO review, but not invoiced until after the Order 11 was issued. The total spending between July 2003 and July 2004 totaled approximately $95,000 and was almost exclusively associated with on-going activities and consultation with First Nation groups that would be affected by the pipeline.

10.9 Please provide a summary by year of any tax deductions taken for any IPC development costs by Terasen Gas Inc. and/or Terasen Inc. in its corporate tax returns. Please do the same for the anticipated tax treatment for the 2005 tax year.

Response:

The tax deductions taken for the IPC development costs by Terasen Gas Inc. are summarized below.

Year	Deducted for tax ($' millions)
2001	2.782
2002	2.339
2003	0.261
2004	0.037
Total	**5.419**

It is anticipated that the 2005 IPC development costs will be deducted for income tax purposes if they are of the same nature as costs incurred in prior years.

10.10 In a table please identify the specific plant accounts that the IPC development costs would be attributed to. Include in the table the account number, account name, dollar amount, and the depreciation rate. Please provide a copy of the Terasen Gas Capitalization Policy for placing plant in-service as specified in the company's policy and procedures manual.

Response:

The following table shows the accounts, dollar amounts and depreciation rates the IPC development cost would be attributed. Please note that the IPC development costs are as at June 30, 2005 and is on a gross basis.

IPC Development Costs

G/L Acct	Account Desription	Dep'n Rate	$
10060	Land - Transmission Plant	0.00%	319,094.03
10062	Compressor - Struct & Improv - Transmission	3.00%	55,062.00
10065	Mains - Transmission	2.00%	4,840,038.05
10067	Measuring & Regulating Equip - Transmissior	10.00%	194,416.02
			5,408,610.10

Please refer to Appendix I to view Terasen Gas' Capitalization Policy.

10.11 Please identify the eligible CCA pool(s), the amount in each CCA pool, and the applicable CCA rate(s) arising from the IPC development costs. Please provide a continuity table from inception of additions to 2010.

Response:

IPC development costs for Income Tax filing purposes have not been charged to a CCA pool but were expensed in the year incurred. For regulatory purposes, the costs could be charged to Class 1 with a 4% rate which would match notionally the costs being added to Southern Crossing Pipeline costs – gas plant in service although no physical assets have been added. The notional CCA continuity schedule is as follows:

Particulars	2005	2006	2007	2008	2009	2010
Capital Cost Allowance / Eligible Capital Expenditure						
Class 1, Opening Balance	$ -	$ -	$ 5,301	$ 5,089	$ 4,885	$ 4,690
Additions	-	5,409	-	-	-	-
CCA Rate	4%	4%	4%	4%	4%	4%
CCA	-	(108)	(212)	(204)	(195)	(188)
Class 1, Closing Balance	$ -	$ 5,301	$ 5,089	$ 4,885	$ 4,690	$ 4,502

Alternatively, the IPC Development costs are expensed and the value of the tax savings is credited to the deferral account (see following table) as per the response in Item 16.6. If a 12 year amortization period is used the results of the revenue impact would be very close to the results shown in Item 16.2.

Particulars		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
SUMMARY: RATE BASE / REVENUE REQUIREMENT														
Rate Base - Mid-Year														
Deferred Charges		-	3,437	3,138	2,839	2,540	2,241	1,942	1,644	1,345	1,046	747	448	149
Working Capital		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base		$ -	$ 3,437	$ 3,138	$ 2,839	$ 2,540	$ 2,241	$ 1,942	$ 1,644	$ 1,345	$ 1,046	$ 747	$ 448	$ 149
Capital Structure														
Debt		67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Equity		33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Rate of Return														
Debt		6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
Equity		9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
Earned Return														
Debt		$ -	$ 160	$ 146	$ 132	$ 118	$ 104	$ 90	$ 76	$ 62	$ 49	$ 35	$ 21	$ 7
Equity		-	102	94	85	76	67	58	49	40	31	22	13	4
Return on Rate Base		-	262	239	216	194	171	148	125	103	80	57	34	11
Depreciation & Amortization Expense		-	299	299	299	299	299	299	299	299	299	299	299	299
Income Tax Expense		-	218	210	212	207	202	194	189	184	179	175	170	165
Total Revenue Requirement		$ -	$ 779	$ 748	$ 727	$ 700	$ 672	$ 641	$ 613	$ 586	$ 558	$ 530	$ 503	$ 475
			From '06	to '17										
Discount Rate / Net Present Value			6.02%	$5,416										
			10.00%	$4,486										
Sales / Transport Volumes Non-Bypass (TJ)	0.8315%	184,858	186,395	187,945	189,508	191,083	192,672	194,274	195,890	197,519	199,161	200,817	202,487	204,170
Ave. Rate Impact		$ -	$ 0.004	$ 0.004	$ 0.004	$ 0.004	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.002	$ 0.002
Deferred Charge														
Gross IPC Development Costs			$ 5,801	$ 3,287	$ 2,988	$ 2,690	$ 2,391	$ 2,092	$ 1,793	$ 1,494	$ 1,195	$ 897	$ 598	$ 299
Tax Provision			(2,215)											
Amortization	8.3%		(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)
End of Year, Balance			$ 3,287	$ 2,988	$ 2,690	$ 2,391	$ 2,092	$ 1,793	$ 1,494	$ 1,195	$ 897	$ 598	$ 299	$ 0

10.12 Please explain how the IPC development costs meet the "available for use" requirement for CCA to be claimed.

Response:

Under the provisions of the Income Tax Act the costs currently do not meet the "available for use" rules and capital cost allowance cannot be claimed on them.

10.13 Please identify any amount of the IPC development costs that is not eligible for CCA treatment and provide the tax deductible disposition of that amount by year.

Response:

For purposes of filing corporate Income Tax returns with the Canada Revenue Agency none of the costs have been or would be included in a CCA pool. For the tax deductible disposition see Response to Item 10.9.

11.0 Reference: Exhibit B-1, p. 12; Attachment 5
AFUDC on IPC Development Costs

11.1 On page 12 the Application states: "…the Company proposes that it is reasonable to calculate AFUDC commencing November 1, 2004, the date the NWN TSA came into effect." Please explain why Terasen Gas believes it should calculate AFUDC from the November 1, 2004 date when the NW Natural Transportation Service Agreement went into effect, matching the determination of AFUDC to the timing of revenue from NW Natural. Does Terasen Gas' reasoning depend on establishing a direct link between IPC and the revenue from NW Natural? What dates does Terasen Gas consider the start of construction and the end of construction for the IPC development costs?

<u>Response</u>:

Terasen Gas' reasoning depends on the link that it has established in the Application, between IPC and the receipt of revenue from NW Natural. As stated in the Application, the company believes that "…the agreement with NWN, along with the significant revenues would not likely have been realized if the IPC project had not been under development."

The activities and costs incurred related to the IPC project were for planning and development, not construction of the project. These planning and development costs were incurred in the period March, 2001 through to July, 2004.

11.2 Attachment 5 shows 5.99 percent and 6.02 percent AFUDC rates used to calculate the $392,322 of AFUDC.

11.2.1 Please provide the reconciliation and source for the AFUDC rates.

<u>Response</u>:

The following table shows the calculation of the AFUDC rates for 2005 and 2004.

Terasen Gas Inc.
Calculation of AFUDC Rates

	2005			2004		
	Weight	Pre-Tax Rate	After Tax Rate	Weight	Pre-Tax Rate	After Tax Rate
Short term debt	6.70%	4.00%	2.62%	9.80%	3.25%	2.13%
Long term debt	60.30%	7.26%	4.76%	57.20%	7.37%	4.83%
Common equity	33.00%	13.79%	9.03%	33.00%	13.97%	9.15%

Weighted average	100.00%	9.19%	6.02%	100.00%	9.15%	5.99%

Tax Rate 34.50%

Source: 2005 short term and long term debt data from approved order G-112-04. 2004 short and long term debt data from approved order G-80-03.

11.2.2 Please provide the latest copy of Terasen Gas' AFUDC Capitalization Policy as specified in the company's policy and procedures manual.

Response:

The following is an excerpt from the Asset Accounting Policy and Procedure Manual:

2.7 Allowance for Funds Used During Construction (AFUDC)

Policy

AFUDC is capitalized on projects under construction whose costs are greater than $50,000 each and which are expected to take three (3) or more months to construct. AFUDC is the cost of capital that is the cost of borrowed funds and a reasonable rate on other funds such as equity, used for the purpose of construction.

Rate Determined

The AFUDC rate is the return on rate base for Terasen Gas as approved by BCUC.

AFUDC Applied

AFUDC is applied to both specific and certain recurring plant expenditures based on previous month-to-date total direct and overhead costs, less contributions in aid of construction received, if any.

AFUDC Begins

AFUDC will commence on the date the project is approved for and ends when the project is placed into service. One-half the rate is applied to eligible projects which start/completed up to the 15th of the month, and the full rate thereafter.

Preliminary Charges

Related preliminary engineering and/or research and development expenditures, accumulated to date of construction are eligible for AFUDC from date of construction.

Adjustment

AFUDC applied to specific projects, may be subject to recalculation or reversal, if the AFUDC criteria is not met or the AFUDC rate is adjusted.

AFUDC Not Applied

AFUDC is not applied on expenditures in the following capital asset classifications:

- capital assets in service
- capital assets held for future use
- capital assets held for resale
- research, development and preliminary engineering
- deferred projects
- projects with budgeted costs less than $50,000
- projects which are expected to be completed in less than three (3) months

11.2.3 What is Terasen Gas' policy for applying short-term interest on a project instead of AFUDC?

Response:

Terasen Gas' policy is to apply short-term interest to projects that are awaiting approval by the Commission. Once approved, the short-term interest is reversed and AFUDC is applied.

11.2.4 Why should an imputed interest be included in the IPC Development costs for a project that is not completed and not "used and useful"?

Response:

As stated in the Response to IR # 11.1, the Company submits that "…the agreement with NWN, along with the significant revenues would not likely have been realized if the IPC project had not been under development." Based on this the Company is of the opinion it is reasonable to include AFUDC.

12.0 Reference: Exhibit B-1, Attachment 4
IPC Development Costs

12.1 Attachment 4 shows $303,000 of "Terasen Internal Labour."

12.1.1 Please clarify if this refers to Terasen Inc. or Terasen Gas Inc. internal labour.

Response:

This refers to Terasen Gas Inc internal labour.

12.1.2 If the IPC development costs are held in the financial books of Terasen Gas Inc., please identify any internal labour charged by Terasen Inc. to Terasen Gas Inc. and how it has conformed to the Transfer Pricing Policy.

Response:

No internal labour was charged by Terasen Inc for IPC development costs.

12.1.3 If the IPC development costs are held in the financial books of Terasen Inc., please identify any internal labour charged by Terasen Gas Inc. to Terasen Inc. and how it has conformed to the Transfer Pricing Policy.

Response:

IPC development costs are held in the financial books of Terasen Gas Inc.

12.2 If Terasen Gas Inc. was charged any other costs not shown on Attachment 4, please identify the amounts. If Terasen Gas Inc. received any funds related to the IPC development costs, please identify the amounts.

Response:

Terasen Gas Inc. did not received any funds related to IPC development costs and was not charged any other costs for ICP development other than those shown in Attachment 4.

12.3 *If total Terasen Gas internal costs were in the order of $303,000, please explain why this relatively modest amount is a credible assessment of the cost of Terasen Gas executive and staff time and other Terasen Gas resources that were used to develop the IPC. Please provide the hours and total charged labour costs by employee. Explain how the charge-out rate was calculated.*

Response:

Terasen Gas internal costs changed to this account relate to staff that were directly involved in project specific activities supporting the development of IPC. Terasen Gas considers that part of the Utility's resource planning responsibility is to identify the need for future resources and the best options for meeting customer requirements, including the investigation of regional pipeline alternatives and such options as IPC. As a result, the cost of internal staff time charged to the IPC account does not include the costs associated with the regional resource assessment and planning effort.

In addition, the majority of the development costs relate to third party consulting costs associated with routing, preliminary engineering design and environmental assessment These activities were managed by the project director, Bill Manery, who in turn charged time to the IPC account on a close to full time basis.

The charge out rate is calculated by adding total base pay, plus incentive payment, plus benefits and dividing by available hours (hours pay minus vacation, statutory holidays and sick time).

The $303,000 represents internal costs that were charge directly to the Project Management category as follows:

Employee	Hours	$'s
William Manery	2,507.25	197,941.65
Hilary Milner	1,278.72	38,557.87
Guy Wassick	333.00	22,025.53
Joy Pollock	295.75	11,537.37
Cynthia Des Brisay	147.55	11,744.98
Douglas Stout	71.60	9,557.08
Mary Tai	62.25	2,331.48
Stephen Grant	53.25	2,410.84
Lorne Sandstrom	43.00	2,436.58
Shelley Onofrechuk	32.50	665.97
Kristopher Pinnell	27.25	864.94
Joseph Haddon	26.50	1,379.33
Caprice Munro	24.00	692.59
Denise McCrae	22.50	646.65
G.Arthur Kanzaki	17.00	958.3
Franjo Sedlar	1.25	48.68
Daniel Phillips	1.00	58.94
Total Internal Labour	**4,944.37**	**303,858.78**

Some internal labour was also charged to other categories and included in the subtotal cost of the various sections of Attachment 4. A summary is attached as follows:

Category	Hours	$'s
Lands	111.25	5,041.29
Communication	120	3,528.70
Aboriginal Affairs	1.25	48.68
Engineering	3	108.16
Route Location	23	528.63
Other	10	516
Total Internal labour	**268.5**	**9,771.46**

12.4 *Attachment 4 is a table of the actual IPC Development Costs. Please provide a similar table comparing the actual to budget costs (including a difference column).*

Response:

The following table compares actual IPC Development Costs relative to budget costs.

	Plan	Actual	Variance
Project Management	**1,869,150**	**1,810,168**	**58,982**
General Project Management	536,408		6,849
Lands activity	430,337	319,094	111,243
Gas supply	84,915	83,835	1,080
Communications	168,376	194,417	(26,041)
First Nations	649,114	683,264	(34,150)
Environment	**1,096,097**	**1,179,765**	**(83,668)**
Field Reconnaissance	885,721	942,680	(56,959)
BC EAO application	191,196	207,305	(16,110)
Aboriginal relations	19,180	29,778	(10,599)
Design	**1,553,638**	**1,565,401**	**(11,763)**
Pipeline design	702,748	708,847	(6,097)
Locate pipeline route	627,953	603,201	24,752
Crossing preliminary designs	222,937	253,356	(30,419)
Stage 2	**896,830**	**853,279**	**43,551**
General consulting costs to manage stage 2	92,000	104,973	(12,974)
Alternate Route Assessment consulting costs	32,395	32,395	0
Detailed environmental field studies	542,373	529,181	13,192
BC EAO Report Preparation	40,000	62,265	(22,265)
Environmental studies re: compressor stations	55,062	55,062	0
Hope to Huntingdon alternative studies	135,000	69,402	65,598
Total Direct Costs	**5,415,715**	**5,408,613**	**7,101**
Afudc		392,321	
Total Costs		5,800,934	

12.5 Attachment 4 shows $83,835 of costs for Gas Supply. Activities identified were consulting fees to draft TSA, precedent agreement, open season documents and provide toll design. Please provide a copy of the largest invoice for each of the identified activities.

Response:

Consulting for preparation of the draft TSA, precedent agreement, and open season documents was provided by Stikeman Elliot. The largest invoice for these activities is included in Appendix J

Consulting related to toll design for IPC was provided by A.S. Cheung & Associates. The largest invoice for this activity is also included in Appendix J.

12.6 Attachment 4 shows $1,179,765 costs for Environment. Please provide a copy of the largest cost invoice for each of: consulting costs for initial field reconnaissance studies, consulting costs to develop BC Environmental Assessment Office application, and consulting assistance to manage aboriginal relations.

Response:

Consulting services for these activities was provided by Westland Resource Group (WRG). The largest invoice related to each of the activities in question is attached as Appendix K. The dollar amounts referenced below are shown near the bottom of the last page of each invoice in the appropriate column of the row titled “Total Cost This Invoice”:

Initial field reconnaissance studies

- June 6, 2001 (WRG Invoice # 01-001-3) includes a total of $177,639 for this activity

Development of the BC Environmental Assessment Office application

- December 7, 2001 (WRG Invoice # 9 01-001-9) includes $50,219 for this activity

Assistance to manage aboriginal relations

- March 4, 2002 (WRG Invoice # 9 01-001012) includes $22,920 for this activity. This amount is shown incorrectly on the invoice as “Environmental Assessment of Selected Route and Access Roads” and was correctly recorded by Terasen as “Involvement with Consultation Program (Public and First Nations)”.

13.0 Reference: Exhibit B-1, p. 10
Environmental Assessment Office

Page 10 of the Application states: "An Application to the Environmental Assessment Office ("EAO") for a Project Approval Certificate was filed on February 19, 2002…"

13.1 Please identify the company that applied for the EAO Project Approval Certificate for IPC.

<u>Response</u>:

The EAO Project Approval Certificate application for ICP is in the name of BC Gas Inc.

13.2 Please identify the company that applied for the EAO Project Approval Certificate for SCP in January 1998.

<u>Response</u>:

The EAO Project Approval Certificate application for SCP submitted in January 1998 is in the name of BC Gas Utility Ltd.

13.3 If the applicant companies are different between the IPC and SCP EAO Project Approval Certificate applications please explain why.

<u>Response</u>:

While SCP was based mainly on meeting Terasen Gas requirements, IPC is intended mainly to serve regional market demands including those of Terasen Gas. A determination as to the ownership structure that will provide the most competitive tolls for IPC while maintaining or enhancing the value of SCP to existing customers had not been completed. At the time of the IPC application the expectation was that an EAO approval issued in the name of BC Gas Inc. would provide the most flexibility to ensure a competitive ownership structure whether the project became part of the utility or was owned by a separate BC Gas entity.

14.0 Reference: Exhibit B-1, pp. 10-12; Attachments 4, 5

14.1 On page 10, Terasen Gas states that NW Natural made a binding commitment during the IPC Open Season to contract for IPC capacity. Did this commitment place NW Natural under any legal obligation to contract for the PG&E SCP capacity when it became apparent that the latter would be available? If it did, please provide a summary of the contractual commitments and timelines, and copies of the supporting documentation.

<u>Response</u>:

No, NWN was under no legal obligation to contract for PG&E SCP capacity as a result of its commitment for IPC capacity.

14.2 Notwithstanding NW Natural's commitment for service on IPC, please discuss whether it is likely that regulatory approval for the IPC would have been granted in circumstances where essentially equivalent service was surplus and available on SCP.

<u>Response</u>:

The SCP service was not surplus and available. PG&E held a long term contract for the capacity. It was only as a result of negotiations between NWN, Terasen Gas and PG&E that this capacity could be used to meet NWN's requirements. If these negotiations had not taken place, PG&E would have continued to control the capacity. Under this scenario, given PG&E's financial circumstances Terasen Gas would have been exposed to lost revenues if PG&E defaulted. Although it is true that Terasen Gas may have been able to mitigate this risk through day to day transactions on interruptible movements if PG&E was in default, Terasen Gas would not have been able to put in place any long term arrangements until such time the contracts could be legally terminated through due process. NWN was seeking long term firm capacity arrangements and would have been required to seek other arrangements if IPC did not proceed and alternate arrangements could not be made.

Terasen Gas or Terasen Inc would not have sought regulatory approval of IPC without firm shipper commitments in place to support the project.

14.3 On page 11, Terasen Gas states that it believes that the SCP Transportation Service Agreement with NW Natural would not likely have been realized if the IPC project had not been under development. Please explain fully the reasoning that supports this belief.

Response:

Following the events of winter 2000/01, NW Natural was seeking firm capacity upstream from Sumas to match their firm NW pipeline capacity beginning in November 2003. At that time, Westcoast capacity was fully contracted and Terasen was developing IPC in response to the constrained market at Huntingdon/Sumas. Prior to the IPC Open Season Terasen held several discussions with NW Natural and other prospective shippers. Terasen Gas had recently completed the Southern Crossing Project, on time and on budget, and by moving ahead with the development of IPC, was able to demonstrate that IPC was a viable alternative serving the Huntingdon/Sumas market place.

As a result, NW Natural agreed to contract for capacity on IPC in response to the Open Season in May 2001, and did not participate in the Westcoast Open season for expansion capacity. If IPC had not been under development, it is Terasen Gas's understanding that NW Natural would have met its requirements by contracting for firm expansion capacity in the Westcoast Open Season. In this case, the opportunity to put in place the SCP Transportation Service Agreement with NW Natural using PG&E capacity would not have presented itself.

Note that at the time of the IPC and Westcoast Open Season in the spring of 2001, the market that competed for supply at Sumas generally accepted that new regional transmission capacity was required to meet the high demand growth that was largely being driven by new electric generation demand. IPC was seen as a viable alternative, and provided an opportunity to diversify capacity upstream from Sumas by providing a firm transportation path back to the Alberta supply basin.

14.4 As Letter No. L-48-02 states, Terasen Gas (previously BC Gas) has a longstanding business relationship with NW Natural related to matters such as Mist Gas Storage. Also, Terasen Gas customers funded activities like regional resource planning work, which concluded that benefits would result from moving gas from Alberta to the Pacific Northwest region. Please explain why Terasen Gas believes that development of IPC made a material incremental impact on the interest that NW Natural would have had in SCP transportation.

Response:

Please see response to BCUC IR, 14.3.

14.5 On page 11, Terasen Gas also states that it believes that development of IPC better positioned Terasen Gas in its dealing with Westcoast. The Application goes on to provide a summary of the events related to the Westcoast 2003 expansion Open Season, that led to a smaller Westcoast 2003 expansion and separate T-south tolls for Kingsvale to Huntingdon. Without in any way downplaying the contribution that Terasen Gas made to realizing this outcome, it would appear that the opportunity to obtain the Kingsvale toll resulted from the Westcoast Open Season and proposed expansion and that Westcoast initiated that Open Season is 2001 to serve the same demand for more supply to Huntingdon/Sumas that Terasen Gas was responding to when it held the IPC Open Season. Please explain whether Terasen Gas believes that, in the absence of IPC, Westcoast would not have proposed an expansion to its system and, if so, why it holds this belief.

Response:

While it is difficult to know if or when Westcoast would have responded to the market pressures prevalent in the immediate aftermath of the extreme market volatility of 2000/01, Terasen believes that Westcoast was influenced by the competitive threat it perceived in the IPC project. Based on the various interactions Terasen Gas had with Westcoast, prior to Westcoast initiating expansion plans, Terasen Gas is of the belief that the timing of Westcoast's Open Season, and its willingness to negotiate an agreement to reduce the proposed build and agree to support a segmented tolling regime on its system were both significantly influenced by the knowledge that Terasen Gas was planning to pursue IPC as a means to ensure economic capacity attached to a secure supply for the regional market. Westcoast clearly viewed, and continues to view IPC as a competitive threat to its market position, and had given no real signals that it was prepared to respond to the apparent market demand for capacity prior to the IPC proposal. The fact that the Westcoast Open Season barely preceded the IPC Open Season, despite Westcoast being larger and more substantially in the business of providing open transportation service to the market region, should be viewed as evidence of Westcoast's reactive response.

Furthermore, Westcoast had resisted every initiative from Terasen that involved the segmentation of tolls in order to allow Terasen to optimize its supply arrangements between northern B.C. and Alberta. Terasen Gas believes that one of the factors that led Westcoast to agree to support segmented tolls was its expectation that its expansion would proceed relatively uncontested, and thereby eliminate the immediate threat it felt IPC posed.

14.6 What would it have cost to develop a conceptual IPC proposal, without the detailed design, First Nations consultation, environmental assessment and environmental approval process, which would have been sufficient to achieve the outcomes related to the NW Natural Agreement and Westcoast Kingsvale tolls. Please set out the basis for the estimate.

Response:

The outcomes related to the NW Natural Agreement and Westcoast Kingsvale tolls were achieved in part because Terasen had developed a credible alternative to meet regional demand growth for gas transportation. An IPC proposal without detailed design, First Nations consultation, an environmental assessment and a subsequent PAC application would not have provided Terasen with enough certainty to proceed with an open-season for IPC since it is would not be possible to assess the feasibility of completing the project without these development activities. It would have been impossible for prospective shippers to assess the likelihood that IPC could achieve its environmental and regulatory approvals and construct the project on time and on budget. The process was an essential step in demonstrating the credibility of IPC as an alternative for regional transportation, as is the case with any new infrastructure project.

15.0 Reference: Exhibit B-1, pp. 10-12; Attachments 4, 5

On page 12, Terasen Gas states that it has indefinitely deferred IPC. On page 50 of the 2005/06 GCP, Terasen Gas states that current market conditions are not expected to support new regional pipeline capacity until 2008 to 2010.

15.1 Does Terasen Gas now consider the IPC project cancelled or indefinitely deferred?

Terasen Gas believes that the IPC project is the most competitive alternative to add pipeline capacity when it is next required for the regional market. The project has been deferred until regional shipper interest in the project is sufficient to justify further development work. The time required for this support to develop is indefinite and therefore Terasen considers the project to be indefinitely deferred.

15.2 What events need to occur (including the timing) for IPC to be reactivated?

Response:

The next stage of development of the IPC project entails completion of detailed environmental, land use, engineering design work. Terasen would seek shipper commitments to IPC before reactivating the project and engaging in these activities.

15.3 Does Terasen Gas expect that IPC will be a contender when new regional pipeline capacity is needed? If so, when would work need to resume on IPC to meet a 2008 in-service date?

Response:

Terasen Gas believes that the IPC project is the most competitive alternative to add pipeline capacity when it is next required for the regional market.

To complete the IPC project one summer of environmental and land use work is required followed by two summers for construction work, therefore November 2008 is the earliest practical in-service date for the project. The steps toward this in-service date are:

- May 2006: Shipper Commitments
- June-August 2006: Complete detailed environmental and land use work
- November 2006: BCUC CPCN filing
- May 2007: Commence Construction
- November 2008: In-service

16.0 Reference: Exhibit B-1, pp. 10-12; Attachments 4, 5
Financial Impact of IPC Development Costs

16.1 On pages 4 and 12, the Application seeks approval to recover $5,408,613 of IPC development costs and AFUDC of $392,321 to the end of December 2005, commencing November 1, 2004 by adding these amounts to the SCP rate base. Please clarify the impacts on ratepayers and Terasen Gas shareholders if the Commission denies this request in its entirety.

Response:

If the costs are disallowed at this time for inclusion in the utility rate base it will have no impact on Terasen Gas's customers (ratepayers) as these costs have been charged to a non rate base account – Preliminary Survey and Investigation.

It is uncertain at this time if the costs should be written off as there is still a possibility the IPC pipeline may be required within the next five years. This is a matter management would continue to discuss with the external auditors as to whether there is sufficient expectation regarding the construction of the IPC pipeline to continue holding the costs in the Preliminary Survey and Investigation or to write off the costs – which the shareholders would bear the burden of the loss.

See also response to BCUC IR1, No. 10.6.2.

16.2 *Please provide a year-by-year schedule showing the impact on ratepayers for the period to 2020 of including the IPC costs in SCP rate base, the net book value of IPC costs at the end of 2020 and the NPV value of these costs at two representative discount rates. For each year, please also show the average rate impact in $/GJ.*

<u>Response</u>:

TERASEN GAS INC.
IPC DEVELOPMENT COSTS TO SCP - COST OF SERVICE
($000)

Line No.	Particulars		1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012
1	**SUMMARY: RATE BASE / REVENUE REQUIREMENT**									
2	Rate Base - Mid-Year									
3	Gas Plant in Service		$ -	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801
4	Accumulated Depreciation		-	(58)	(174)	(290)	(406)	(522)	(638)	(754)
5	Total Rate Base		$ -	$ 5,743	$ 5,627	$ 5,511	$ 5,395	$ 5,279	$ 5,163	$ 5,047
6										
7	Capital Structure									
8	Debt		67%	67%	67%	67%	67%	67%	67%	67%
9	Equity		33%	33%	33%	33%	33%	33%	33%	33%
10	Total		100%	100%	100%	100%	100%	100%	100%	100%
11										
12	Rate of Return									
13	Debt		6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
14	Equity		9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
15										
16	Earned Return									
17	Debt		$ -	$ 267	$ 261	$ 256	$ 250	$ 245	$ 240	$ 234
18	Equity		-	171	168	164	161	157	154	150
19	Return on Rate Base		-	438	429	420	411	402	394	385
20										
21	Depreciation & Amortization Expense		-	116	116	116	116	116	116	116
22	Income Tax Expense		-	105	43	42	44	47	49	51
23										
24	Total Revenue Requirement		$ -	$ 659	$ 588	$ 578	$ 572	$ 565	$ 558	$ 552
25				From '06	to '20					
26	Discount Rate / Net Present Value			6.02%	$5,411					
27				10.00%	$4,289					
28	Sales / Transport Volumes Non-Bypass (TJ)	0.8315%	184,858	186,395	187,945	189,508	191,083	192,672	194,274	195,890
29										
30	Ave. Rate Impact		$ -	$ 0.004	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003
31										
32	Gross IPC Development Costs			$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801
33	Depreciation Provision	2.0%		(116)	(232)	(348)	(464)	(580)	(696)	(812)
34	End of Year, Net Plant			$ 5,685	$ 5,569	$ 5,453	$ 5,337	$ 5,221	$ 5,105	$ 4,989

TERASEN GAS INC.
IPC DEVELOPMENT COSTS TO SCP - COST OF SERVICE
($000)

Line No.	Particulars		9 2013	10 2014	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020
1	**SUMMARY: RATE BASE / REVENUE REQUIREMENT**									
2	Rate Base - Mid-Year									
3	Gas Plant in Service		$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801
4	Accumulated Depreciation		(870)	(986)	(1,102)	(1,218)	(1,334)	(1,450)	(1,566)	(1,682)
5	Total Rate Base		$ 4,931	$ 4,815	$ 4,699	$ 4,583	$ 4,467	$ 4,351	$ 4,235	$ 4,119
6										
7	Capital Structure									
8	Debt		67%	67%	67%	67%	67%	67%	67%	67%
9	Equity		33%	33%	33%	33%	33%	33%	33%	33%
10	Total		100%	100%	100%	100%	100%	100%	100%	100%
11										
12	Rate of Return									
13	Debt		6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
14	Equity		9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
15										
16	Earned Return									
17	Debt		$ 229	$ 224	$ 218	$ 213	$ 207	$ 202	$ 197	$ 191
18	Equity		147	143	140	137	133	130	126	123
19	Return on Rate Base		376	367	358	349	341	332	323	314
20										
21	Depreciation & Amortization Expense		116	116	116	116	116	116	116	116
22	Income Tax Expense		53	54	56	58	59	60	61	62
23										
24	Total Revenue Requirement		$ 545	$ 538	$ 530	$ 523	$ 515	$ 508	$ 500	$ 492
25										
26	Discount Rate / Net Present Value									
27										
28	Sales / Transport Volumes Non-Bypass (TJ)	0.8315%	197,519	199,161	200,817	202,487	204,170	205,868	207,580	209,306
29										
30	Ave. Rate Impact		$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.002	$ 0.002	$ 0.002
31										
32	Gross IPC Development Costs		$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801
33	Depreciation Provision	2.0%	(928)	(1,044)	(1,160)	(1,276)	(1,392)	(1,508)	(1,624)	(1,740)
34	End of Year, Net Plant		$ 4,873	$ 4,757	$ 4,641	$ 4,525	$ 4,409	$ 4,293	$ 4,177	$ 4,061

16.3 Would recording IPC costs in the SCP rate base have any different outcomes than recording the costs in Terasen Gas' rate base in general? If there are differences, please explain them and provide a schedule similar to that requested in the preceding question.

Response:

If the assumptions surrounding the treatment of costs for charging the IPC Development Costs to the gas plant in service with a 2% depreciation rate and placing the direct costs (costs excluding AFUDC) into the Class 1 CCA pool are constant then the impact on the utility's revenue requirement will be unchanged.

In performing the fully allocated cost of service study the SCP costs are allocated only to firm sales and firm transport customers except for bypass customers and large industrials (Rate Schedule 22B) who are located in the Columbia Service Area. The Rate Schedule 22B customers are served from transmission laterals that are upstream from the Yahk interconnect with the Trans Canada Pipeline (B.C.).

All other transmission related costs, except for the Byron Creek lateral, are allocated to all customers based on their relative proportion of the coincident peak demand. This allocation has no impact on the setting of rates for bypass customers. Interruptible customers (Lower Mainland Rate 22 and all Rate Schedule 27) have a zero allocation. Although the costs for IPC Development would be allocated to bypass customers the recovery of those costs through rates would still occur from all non-bypass customers.

The sales / transport volumes in the preceding schedule include the Rate Schedule 22B customers, whose volumes in 2005 are 2,804 TJ. The inclusion or exclusion of the Rate Schedule 22B customers is too small to have any impact on the average rate impact of $0.003 per gigajoule.

16.4 Please clarify whether any of the IPC costs relate to facilities, including compression, which were included in the CPCN Application and approved by Order No. C-11-99.

Response:

The IPC project involves expansion of SCP through construction of additional compressor stations and a 246 kilometre 24-inch pipeline connecting SCP near Oliver to the Huntingdon hub.

The only IPC cost related to facilities approved by Order No. C-11-99 (SCP facilities) are for studies of the modifications to these facilities that would be required for their use in conjunction with IPC. The following issues were considered during the development of IPC:

- Yahk Station – odourization modifications
- SCP pipeline – pipeline capacity with added compressor stations
- Kitchener Compressor Station – added compressor units
- Oliver Station – odourization modifications and modifications for the inter-connection of IPC

16.5 Please explain why Terasen Gas proposes, on the basis that IPC is effectively an expansion and extension of the SCP and has added value to SCP, that IPC costs be added to the SCP rate base. Why should IPC be considered an expansion of SCP rather than more generally of the Interior Transmission System?

Response:

The SCP project consisted of a new 310 kilometer 24" pipeline from Yahk to Oliver and new compression facilities at Kitchener and Hedley. Capacity on the existing Oliver to Kingsvale line was then used to provide up to 105 mmcfd of capacity to Huntingdon via the Westcoast system from Kingsvale South.

There are two major components of the IPC project, first an expansion of SCP pipeline capacity through the addition of 3 new compressor stations on the SCP transmission system, and second the extension of the SCP pipeline to serve the Huntingdon market place through the construction of a new 246 kilometre 24" pipeline from Oliver to Huntingdon. The combined IPC and SCP facilities would have been used to provide transportation capacity from Yahk to Huntingdon to serve Terasen Gas and other shippers, which is the basis for considering IPC an expansion of SCP. SCP also serves the Terasen Gas customers on the Interior Transmission System north of Oliver, however IPC will not add to this service.

16.6 *Please provide a year by year schedule showing the costs to ratepayers of recording IPC costs in a rate base deferral account and amortizing the amount over, for example, five years commencing January 2006, and the NPV costs at two representative discount rates. For each year, please also show the average rate impact in $/GJ.*

Response:

The following table includes AFUDC but excludes actual tax savings booked to the balance sheet.

Particulars		2005	2006	2007	2008	2009	2010
SUMMARY: RATE BASE / REVENUE REQUIREMENT							
Rate Base - Mid-Year							
Deferred Charges		-	3,227	2,510	1,793	1,076	359
Working Capital		-	-	-	-	-	-
Total Rate Base		$ -	$ 3,227	$ 2,510	$ 1,793	$ 1,076	$ 359
Capital Structure							
Debt		67%	67%	67%	67%	67%	67%
Equity		33%	33%	33%	33%	33%	33%
Total		100%	100%	100%	100%	100%	100%
Rate of Return							
Debt		6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
Equity		9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
Earned Return							
Debt		$ -	$ 150	$ 117	$ 83	$ 50	$ 17
Equity		-	96	75	53	32	11
Return on Rate Base		-	246	191	137	82	27
Depreciation & Amortization Expense		-	717	717	717	717	717
Income Tax Expense		-	435	420	426	415	403
Total Revenue Requirement		$ -	$ 1,398	$ 1,328	$ 1,280	$ 1,214	$ 1,147
			From '06	to '10			
Discount Rate / Net Present Value			6.02%	$5,391			
			10.00%	$4,872			
Sales / Transport Volumes Non-Bypass (TJ)	0.8315%	184,858	186,395	187,945	189,508	191,083	192,672
Ave. Rate Impact		$ -	$ 0.007	$ 0.007	$ 0.007	$ 0.006	$ 0.006
Deferred Charge							
Gross IPC Development Costs			$ 5,801	$ 2,869	$ 2,152	$ 1,434	$ 717
Tax Provision			(2,215)				
Amortization	20.0%		(717)	(717)	(717)	(717)	(717)
End of Year, Balance			$ 2,869	$ 2,152	$ 1,434	$ 717	$ -

16.7 *Please repeat the foregoing question assuming the IPC costs are recorded in a deferral account that does not provide return or interest to Terasen Gas.*

Response:

The following table excludes AFUDC and credits actual tax savings booked to the balance sheet. The deferred costs are not included in rate base thus no earned return is calculated.

Particulars		2005	2006	2007	2008	2009	2010
SUMMARY: RATE BASE / REVENUE REQUIREMENT							
Rate Base - Mid-Year							
Deferred Charges		-	-	-	-	-	-
Working Capital		-	-	-	-	-	-
Total Rate Base		$ -	$ -	$ -	$ -	$ -	$ -
Capital Structure							
Debt		67%	67%	67%	67%	67%	67%
Equity		33%	33%	33%	33%	33%	33%
Total		100%	100%	100%	100%	100%	100%
Rate of Return							
Debt		6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
Equity		9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
Earned Return							
Debt		$ -	$ -	$ -	$ -	$ -	$ -
Equity		-	-	-	-	-	-
Return on Rate Base		-	-	-	-	-	-
Depreciation & Amortization Expense		-	639	639	639	639	639
Income Tax Expense		-	336	336	353	353	353
Total Revenue Requirement		$ -	$ 975	$ 975	$ 992	$ 992	$ 992
			From '06	to '10			
Discount Rate / Net Present Value			6.02%	$4,146			
			10.00%	$3,732			
Sales / Transport Volumes Non-Bypass (TJ)	0.8315%	184,858	186,395	187,945	189,508	191,083	192,672
Ave. Rate Impact		$ -	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005
Deferred Charge							
Gross IPC Development Costs			$ 5,409	$ 2,555	$ 1,916	$ 1,278	$ 639
Tax Provision			(2,215)				
Amortization	20.0%		(639)	(639)	(639)	(639)	(639)
End of Year, Balance			$ 2,555	$ 1,916	$ 1,278	$ 639	$ -

Summary of Financial Impacts

17.0 Reference: Exhibit B-1, pp. 13-15

17.1 Please combine the schedules requested in the preceding questions 1.1, 4.1 and 16.2 into a single schedule showing the impact on annual and total NPV revenue requirements of all the transactions addressed in the Application.

Response:

TERASEN GAS INC.
IPC DEVELOPMENT COSTS TO SCP (Cost of Service) and MITIGATION ACTIVITIES
($000)

Line No.	Particulars	1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012
1	**SUMMARY: RATE BASE / REVENUE REQUIREMENT (Reference Question #16.2)**								
2	Rate Base - Mid-Year								
3	Gas Plant in Service	$ -	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801
4	Accumulated Depreciation	-	(58)	(174)	(290)	(406)	(522)	(638)	(754)
5	Total Rate Base	$ -	$ 5,743	$ 5,627	$ 5,511	$ 5,395	$ 5,279	$ 5,163	$ 5,047
6									
7	Capital Structure								
8	Debt	67%	67%	67%	67%	67%	67%	67%	67%
9	Equity	33%	33%	33%	33%	33%	33%	33%	33%
10	Total	100%	100%	100%	100%	100%	100%	100%	100%
11									
12	Rate of Return								
13	Debt	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
14	Equity	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
15									
16	Earned Return								
17	Debt	$ -	$ 267	$ 261	$ 256	$ 250	$ 245	$ 240	$ 234
18	Equity	-	171	168	164	161	157	154	150
19	Return on Rate Base	-	438	429	420	411	402	394	385
20									
21	Depreciation & Amortization Expense	-	116	116	116	116	116	116	116
22	Income Tax Expense	-	105	43	42	44	47	49	51
23									
24	Total Revenue Requirement	$ -	$ 659	$ 588	$ 578	$ 572	$ 565	$ 558	$ 552
25									
26	**SUMMARY: PG&E and NW Natural Agreements (Reference Question #1.1)**								
27	PG&E Demand Charges	$ (3,600)	$ (3,600)	$ (3,600)	$ (3,600)	$ (3,600)	$ (3,800)	$ (4,800)	$ (4,800)
28	NW Natural Annual Demand Charges	7,298	7,298	7,298	7,298	7,298	7,581	8,995	8,995
29	PG&E Termination Payment	-	(825)	(825)	(825)	(825)	(712)	(145)	(145)
30	PG&E Peaking Arrangement Adjustment	1,318	1,318	1,318	1,318	1,318	1,318	1,318	1,318
31	Other Revenue/Cost								
32	TCPL Cost - 6 MMcfd	(537)	(537)	(537)	(537)	(537)	(537)	(537)	(537)
33	TCPL Mitigation - 6 MMcfd	350	350	350	350	350	350	350	350
34	Amortization of Deferral Account								
35	Deferred Revenue and SCP Mitigation	(503)	(503)	(503)	(503)	(503)	(1,601)	-	-
36	PG&E Termination Payments	-	(158)	(158)	(158)	(158)	-	-	-
37									
38	Total Net Benefit / (Cost)	$ 4,326	$ 3,343	$ 3,343	$ 3,343	$ 3,343	$ 2,599	$ 5,181	$ 5,181
39									
40	**SUMMARY: BC Hydro SCP TSA and Peaking Agreement (Reference Question #4.1)**								
41	BC Hydro Annual Demand Charges	$ (602)	$ (3,600)	$ (3,600)	$ (3,600)	$ (3,600)	$ (3,800)	$ -	$ -
42	Release of Westcoast Capacity	988	6,899	6,899	6,899	6,899	6,899	6,899	6,899
43	Huntingdon Downstream Resources	(204)	(1,215)	(1,174)	(1,220)	(1,293)	(1,291)	(1,291)	(1,291)
44	Kingsgate Peaking Arrangement	44	263	277	279	279	279	279	279
45									
46	Total Net Benefit / (Cost)	$ 226	$ 2,347	$ 2,401	$ 2,358	$ 2,284	$ 2,087	$ 5,887	$ 5,887
47									
48	**Total Net Benefit to Revenue Requirement**	**$ 4,552**	**$ 5,031**	**$ 5,156**	**$ 5,123**	**$ 5,056**	**$ 4,121**	**$ 10,509**	**$ 10,515**
49	(Lines 24 + 38 + 46)								
50				**From 2005-2020**					
51	Discount Rate / Net Present Value	6.02%		$78,454					
52		10.00%		$57,712					
53	Sales / Transport Volumes Non-Bypass (TJ) 0.8315%	184,858	186,395	187,945	189,508	191,083	192,672	194,274	195,890
54									
55	Rate Impact: Average Benefit / GJ	$ 0.025	$ 0.027	$ 0.027	$ 0.027	$ 0.026	$ 0.021	$ 0.054	$ 0.054

TERASEN GAS INC.
IPC DEVELOPMENT COSTS TO SCP (Cost of Service) and MITIGATION ACTIVITIES
($000)

Line No.	Particulars		9 2013	10 2014	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020
1	**SUMMARY: RATE BASE / REVENUE REQUIREMENT (Reference Question #16.2)**									
2	Rate Base - Mid-Year									
3	Gas Plant in Service		$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801	$ 5,801
4	Accumulated Depreciation		(870)	(986)	(1,102)	(1,218)	(1,334)	(1,450)	(1,566)	(1,682)
5	Total Rate Base		$ 4,931	$ 4,815	$ 4,699	$ 4,583	$ 4,467	$ 4,351	$ 4,235	$ 4,119
6										
7	Capital Structure									
8	Debt		67%	67%	67%	67%	67%	67%	67%	67%
9	Equity		33%	33%	33%	33%	33%	33%	33%	33%
10	Total		100%	100%	100%	100%	100%	100%	100%	100%
11										
12	Rate of Return									
13	Debt		6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
14	Equity		9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%	9.03%
15										
16	Earned Return									
17	Debt		$ 229	$ 224	$ 218	$ 213	$ 207	$ 202	$ 197	$ 191
18	Equity		147	143	140	137	133	130	126	123
19	Return on Rate Base		376	367	358	349	341	332	323	314
20										
21	Depreciation & Amortization Expense		116	116	116	116	116	116	116	116
22	Income Tax Expense		53	54	56	58	59	60	61	62
23										
24	Total Revenue Requirement		$ 545	$ 538	$ 530	$ 523	$ 515	$ 508	$ 500	$ 492
25										
26	**SUMMARY: PG&E and NW Natural Agreements (Reference Question #1.1)**									
27	PG&E Demand Charges		$ (4,800)	$ (4,800)	$ (4,800)	$ (4,800)	$ (4,800)	$ (4,800)	$ (4,800)	$ (4,800)
28	NW Natural Annual Demand Charges		8,995	8,995	8,995	8,995	8,995	8,995	8,995	8,995
29	PG&E Termination Payment		(145)	(145)	(145)	(145)	(145)	(145)	(121)	
30	PG&E Peaking Arrangement Adjustment		1,318	1,318	1,318	1,318	1,318	1,318	1,318	1,318
31	Other Revenue/Cost									
32	TCPL Cost - 6 MMcfd		(537)	(537)	(537)	(537)	(537)	(537)	(537)	(537)
33	TCPL Mitigation - 6 MMcfd		350	350	350	350	350	350	350	350
34	Amortization of Deferral Account									
35	Deferred Revenue and SCP Mitigation		-	-	-	-	-	-	-	-
36	PG&E Termination Payments		-	-	-	-	-	-	-	-
37										
38	Total Net Benefit / (Cost)		$ 5,181	$ 5,181	$ 5,181	$ 5,181	$ 5,181	$ 5,181	$ 5,205	$ 5,326
39										
40	**SUMMARY: BC Hydro SCP TSA and Peaking Agreement (Reference Question #4.1)**									
41	BC Hydro Annual Demand Charges		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Release of Westcoast Capacity		6,899	6,899	6,899	6,899	6,899	6,899	6,899	6,899
43	Huntingdon Downstream Resources		(1,291)	(1,291)	(1,291)	(1,291)	(1,291)	(1,291)	(1,291)	(1,291)
44	Kingsgate Peaking Arrangement		279	279	279	279	279	279	279	279
45										
46	Total Net Benefit / (Cost)		$ 5,887	$ 5,887	$ 5,887	$ 5,887	$ 5,887	$ 5,887	$ 5,887	$ 5,887
47										
48	**Total Net Benefit to Revenue Requirement**		**$ 10,522**	**$ 10,529**	**$ 10,537**	**$ 10,544**	**$ 10,552**	**$ 10,559**	**$ 10,591**	**$ 10,720**
49	(Lines 24 + 38 + 46)									
50										
51	Discount Rate / Net Present Value									
52										
53	Sales / Transport Volumes Non-Bypass (TJ)	0.8315%	197,519	199,161	200,817	202,487	204,170	205,868	207,580	209,306
54										
55	Rate Impact: Average Benefit / GJ		$ 0.053	$ 0.053	$ 0.052	$ 0.052	$ 0.052	$ 0.051	$ 0.051	$ 0.051

18.0 Reference: Exhibit B-1
Summary of Accounts

18.1 For all IPC and SCP related transactions please provide an activity and balance summary of rate base accounts and non-rate base accounts by year for 2003 actual, 2004 actual and 2005 projected from the 2004 Annual Review, identified by company name, account number, account name, account description, and explanation for the transaction. Provide references to other detailed information request responses, where appropriate.

Response:

Terasen Gas Inc.
Inland Pacific Connector Transactions

Labour		275,077.69
Employee Expenses		70,591.08
Supplies		17,487.45
Computers		4,887.74
Contractors		4,462,029.71
Promotions & Advertising		115,883.03
Fees & Administration		40,757.08
Facilities		134,175.49
Balance - December 31, 2002		5,120,889.27
2003 Transactions		
Labour	34,126.17	
Employee Expenses	4,035.02	
Supplies	122.55	
Computers	53.75	
Contractors	206,279.93	
Promotions & Advertising	13,045.55	
Fees & Administration	3,392.69	261,055.66
Balance - December 31, 2003		5,381,944.93
2004 Transactions		
Labour	1,911.33	
Contractors	31,812.71	
Fees & Administration	3,000.00	36,724.04
Balance - December 31, 2004		5,418,668.97
2005 Transactions		
Labour	272.55	
Contractors	-10,331.42	-10,058.87
Balance - June 30, 2005		5,408,610.10

Terasen Gas Inc.
Southern Crossing Pipeline Transactions - Rate Base
Cost

G/L Acct	Description	12/31/02	Additions	12/31/03	Additions	12/31/04	Additions	Retirements	12/31/05
10060	TP Land	264,357		264,357		264,357			264,357
10060	TP Land Rights	23,226,875	27,595	23,254,471		23,254,471			23,254,471
10062	TP Compressor Structures	3,427,213	4,203	3,431,416		3,431,416			3,431,416
10063	TP Meas/Reg Structures	237,618		237,618		237,618			237,618
10064	TP Other Structures	4,081,842		4,081,842		4,081,842			4,081,842
10065	TP Transmission Pipeline	327,428,892	15,608	327,444,500	-274,716	327,169,785	-418,560	-70,182	326,681,042
10066	TP Compressor Equipment	33,606,307	10,743	33,617,050	-7,131	33,609,918			33,609,918
10067	TP Meas/Reg Equipment	1,978,929	2	1,978,931		1,978,931		-64,515	1,914,416
10067	TP Telemetry Equipment	92,100	6,721	98,822		98,822			98,822
10075	DS Mains	10,675		10,675		10,675			10,675
10077	DS Meas/Reg Additions	20,368		20,368		20,368			20,368
10083	GP Computer Hardware	68,414		68,414		68,414			68,414
10083	GP Computer Software	43,306		43,306		43,306			43,306
10086	GP Small Tools/Equipment	72,505		72,505		72,505			72,505
10088	GP Radio Equipment	513,421		513,421		513,421			513,421
11610	Specific AUC AFUDC (on)	486	41,933	42,419	-26,061	16,358	494,708		511,066
		395,073,308	106,806	395,180,113	-307,908	394,872,205	76,148	-134,698	394,813,656

Terasen Gas Inc.
Southern Crossing Pipeline Transactions - Rate Base
Accumulated Depreciation

G/L Acct	Description	12/31/02	Depreciation	12/31/03	Depreciation	12/31/04	Depreciation	Retirements	12/31/05
10500	TP Land	0	0	0	0	0			0
10500	TP Land Rights	-379,697		-379,697		-379,697			-379,697
10500	TP Compressor Structures	-148,598	-101,516	-250,114	-102,942	-353,057	-102,942		-455,999
10500	TP Meas/Reg Structures	-14,216	-7,129	-21,345	-7,129	-28,473	-7,129		-35,602
10500	TP Other Structures	-111,293	-122,455	-233,748	-122,455	-356,204	-122,455		-478,659
10500	TP Transmission Pipeline	-12,362,685	-6,638,673	-19,001,357	-6,542,390	-25,543,747	-6,535,988	4,265	-32,075,470
10500	TP Compressor Equipment	-1,918,345	-1,010,493	-2,928,838	-1,008,511	-3,937,349	-1,008,278		-4,945,627
10500	TP Meas/Reg Equipment	-115,601	-59,368	-174,969	-59,368	-234,337	-59,368	9,283	-284,422
10500	TP Telemetry Equipment	-23,822	-9,210	-33,032	-9,882	-42,914	-9,882		-52,797
10500	DS Mains	-427	-214	-641	-214	-854	-214		-1,068
10500	DS Meas/Reg Additions	-1,036	-611	-1,647	-611	-2,258	-611		-2,869
10500	GP Computer Hardware	-21,020	-13,683	-34,703	-13,683	-48,386	-13,683		-62,069
10500	GP Computer Software	-9,937	-5,413	-15,350	-5,413	-20,763	-5,413		-26,176
10500	GP Small Tools/Equipment	-7,182	-3,625	-10,807	-3,625	-14,432	-3,625		-18,058
10500	GP Radio Equipment	-94,159	-51,342	-145,501	-51,342	-196,843	-51,342		-248,185
10500	Specific AUC AFUDC (on)	0	0	0	0	0			0
		-15,208,019	-8,023,731	-23,231,750	-7,927,566	-31,159,316	-7,920,931	13,549	-39,066,698

For SCP related transactions, see Response to Question 19.0.

18.2 *For all IPC and SCP related transactions please provide an activity summary of revenues, notional revenues, expenses, notional expenses by year for 2003 actual, 2004 actual and 2005 projected from the 2004 Annual Review, identified by company name, account number, account name, account description, and explanation for the transaction. Provide references to other detailed information request responses, where appropriate.*

Response:

The SCP mitigation revenue is calculated based on a Commission pre-approved formula that reduces overall costs for all customers. Consistent with this pre-approved formula Terasen Gas does not stream revenue. All the SCP transactions have been filed with the Commission in accordance with Commission orders.

For IPC related transactions, see response to Question 18.1
For SCP related transactions, see response to Question 19.1.4

19.0 Reference: Exhibit B-1
Summary of Deferral Accounts

19.1 The Terasen Gas 2004 Annual Review materials (Section A, Tab 3, pp. 11.1 & 11.3) identify three SCP related deferral accounts for 2004 and 2005:

- *SCP Net Mitigation Revenues #17912*
- *SCP West to East Transmission #17913*
- *SCP PG&E Contract Cancellation #17936*

19.1.1 Please confirm that these three accounts are all the actual SCP related deferral accounts, and that the "SCP Deferral Account" referred to in the Application and shown in Attachment 2 is the sum of the three accounts. If the foregoing is not correct, or if there is an additional proposed SCP deferral account please identify and explain.

Response:

The SCP Deferral Account referred to in the Application and shown in Attachment 2 is only for SCP PG&E Contract Cancellation #17936 and is not the sum of the three accounts.

Details in support of the three deferral accounts can be found under response to Question 19.1.4.

19.1.2 For the SCP deferrals, please list the Orders approving additions and amortization. Also include copies of the relevant sections of the applications that were approved.

Response:

SCP Net Mitigation Revenues #17912	G-7-03, page 41
SCP West to East Transmission #17913	G-7-03, G-124-00, G-123-01
SCP PG&E Contract Cancellation #17936	L-48-02

Please refer to Appendix L for copies of the Commission Orders noted above.

19.1.3 Please cross-reference each request for approval in the Application to the three identified deferral accounts, where applicable.

<u>Response</u>:

There is no need to cross reference each request In the SCP IPC application as there is only one request which is associated with the three deferral accounts noted above.

Request No. 13 of the Application which seeks approval of the recovery mechanism for the PG&E termination payments and recovery of the SCP deferral account related to the Interim Period, effective January 1, 2006, is associated with the SCP Net Mitigation Revenues #17912 deferral account.

19.1.4 For each Deferral account please provide a summary since the year of inception to the final year of proposed amortization: the beginning balance, gross additions, tax deductions, net additions, amortization, and ending balance. Please indicate the tax rates and amortization method used. Also, provide a table of gross and cumulative additions for each deferral account.

<u>Response</u>:

Please refer to Appendix M for summary schedules for accounts 17912, 17913, and 17936.

19.1.5 For each deferral account addition please provide a reconciliation of how the additions were derived and its relation to any revenue and expense amounts in each approved Test Year.

<u>Response</u>:

Details in support of the deferral accounts can be found under response to Question 19.1.4.

20.0 Reference: Exhibit B-1, pp. 6, 11

20.1 Pages 6 and 11 include references to "TGVI". Please confirm that the references instead should be to Terasen Gas Inc.

Response:

Confirmed, references on pages 6 and 11 to "TGVI" should read "TGI".

Appendix A

Information Request: 1.1

Reference: **Attachment 3b Revised (T-South = $0.35)**

Line	Item	1 2003	2 2004	3 2005	4 2006	5 2007	6 2008	7 2009	8 2010	9 2011	10 2012	11 2013	12 2014	13 2015	14 2016	15 2017	16 2018	17 2019	18 2020
1	PG&E Demand Charges (Line Item 2) **	-$3,600	-$3,600	-$3,600	-$3,600	-$3,600	-$3,600	-$3,600	-$3,800	-$4,800	-$4,800	-$4,800	-$4,800	-$4,800	-$4,800	-$4,800	-$4,800	-$4,800	-$4,800
2	NWN Annual Demand Charges (Line Item 14)		$1,216	$7,298	$7,298	$7,298	$7,298	$7,298	$7,581	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995
3	Mitigation Revenue Earned in 2003 and 2004- TCPL Mitigation	$2,848	$3,093																
4	Cost of TransCanada Pipelines LTD (TCPL) Capacity	-$5,053	-$5,053																
5	PG&E Termination Payment (Line Item 15)				-$825	-$825	-$825	-$825	-$712	-$145	-$145	-$145	-$145	-$145	-$145	-$145	-$145	-$121	
6	PG&E Peaking Arrangement Adjustment (Line Item 43)	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318
7	**Other Revenue/Cost**																		
8	TCPL Cost - 6 MMcfd			-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537	-$537
9	TCPL Mitigation - 6 MMcfd			$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350
10	**Amortization of Deferral Account**																		
11	Deferred Revenue and SCP Mitigation			-$503	-$503	-$503	-$503	-$503	-$1,601										
12	PG&E Termination Payments				-$158	-$158	-$158	-$158											
13																			
14	Total Net Benefit/(Cost)	-$887	$1,174	$4,326	$3,343	$3,343	$3,343	$3,343	$2,599	$5,181	$5,181	$5,181	$5,181	$5,181	$5,181	$5,181	$5,181	$5,205	$5,326
15																			
16	**Present Value of Net Benefit**	To 31 Oct 2010	To 31 Oct 2020																
17	NPV @6.02% from 2005	$16,831	$43,721																
18	FV 2003 and 2004 @ 6.02%	$247	$247																
19	NPV @6.02% 2003 to2010	**$17,077**	**$43,968**																
20																			
21	NPV @10% from 2005	$15,032	$33,038																
22	FV 2003 and 2004 @ 10%	$218	$247																
23	NPV @10% 2003 to2010	**$15,251**	**$33,285**																
24																			
25	**Deferral Account:**																		
26	PG&E Demand Charges (Line Item 2)	$3,600	$3,000																
27	SCP Mitigation	-$2,200	-$515																
28	PG&E Termination Payments		$138	$825															
29	Total Deferral Account	$1,400	$2,623	$825															
30																			
31	** Note: PG&E Demand Charges for 2003 ($3600) and 2004 ($3000) not included in Total Net Benefit /(Cost). Charges included in a Deferral Account (Line21)																		

Information Request: 4.1

Reference: **Attachment 3b Revised (T-South = $0.35)**

Line	Item	1 Nov-Dec2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012	9 2013	10 2014	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020
1	BC Hydro Annual Demand Charges (Line Item 3) [1]	-$602	-$3,600	-$3,600	-$3,600	-$3,600	-$3,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Release of Westcoast Capacity (Line Item 49)	$988	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899	$6,899
3	Huntingdon Downstream Resources (Line Item 50)	-$204	-$1,215	-$1,174	-$1,220	-$1,293	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291
4	Kingsgate Peaking Arrangement (Line Item 51)	$44	$263	$277	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279
5	Total Net Benefit/(Cost)	$226	$2,347	$2,401	$2,358	$2,284	$2,087	$5,887	$5,887	$5,887	$5,887	$5,887	$5,887	$5,887	$5,887	$5,887	$5,887
6																	
7	**Present Value of Net Benefit**	To 31 Oct 2010	To 31 Oct 2020														
8	NPV @6.02%	$9,357	$39,836														
9																	
10	NPV @10%	$8,156	$28,573														

1) After 2010 BC Hydro annual demand charge goes to zero as BC Hydro has the option to turnback its capacity on SCP

Information Request: 4.1

T South = $0.40 Sensitivity [1]

Line Item		1 Nov-Dec2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012	9 2013	10 2014	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020
1	BC Hydro Annual Demand Charges (as per Attach. 3b Revised - Line Item 3)	-$602	-$3,600	-$3,600	-$3,600	-$3,600	-$3,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Release of Westcoast Capacity (as per Att3b Line Item 49)	$988	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884	$7,884
3	Huntingdon Downstream Resources (as per Attach. 3b Revised - Line Item 50)	-$204	-$1,215	-$1,174	-$1,220	-$1,293	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291	-$1,291
4	Kingsgate Peaking Arrangement (as per Attach. 3b Revised - Line Item 51)	$44	$263	$277	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279	$279
5	Total Net Benefit/(Cost)	$226	$3,333	$3,387	$3,343	$3,270	$3,072	$6,872	$6,872	$6,872	$6,872	$6,872	$6,872	$6,872	$6,872	$6,872	$6,872
6																	

Line		To 31 Oct 2010	To 31 Oct 2020
7	**Present Value of Net Benefit**		
8	NPV @6.02%	$13,271	$48,852
9			
10	NPV @10%	$11,552	$35,387

1) Also see response to BCUC #1, Item 4.6.

Appendix B

3.0 Reference: 2005/06 GCP

3.1 *Page 66 of the 2005/06 GCP notes that effective November 1, 2005, Terasen Gas Midstream is faced with additional SCP capacity from the B.C. Hydro and Power Authority ("BC Hydro") Put Option and termination of the BC Hydro Peaking Agreement. Please confirm that these changes are subject to the outcome of Terasen Gas' application dated June 1, 2005 for approval of transactions related to the Southern Crossing Pipeline ("SCP") and the Inland Pacific Connector.*

Response:

Yes.

3.3 *Table 12 on Page 83 shows an increase of 83.0 TJ/d in Kingsgate seasonal/spot/peaking for 2005/06 and Table 25 indicates that 50.0 TJ/d of the supply is expected to be peaking. (This is consistent with the statement on page 67 that BC Hydro peaking will be replaced with peaking at Kingsgate). Please provide a one-to-one comparison of the annual demand (fixed) and variable cost of 56.5 TJ/d of BC Hydro peaking and the same amount of newly purchased firm peaking at Kingsgate for 2005/06. Also, please discuss Terasen Gas' confidence level that it will be able to source this amount of firm peaking at Kingsgate at the cost it estimates.*

Response:

Line		Normal Year	Warm Year	Design Year
1	Days used	5	0	15
2		56,500	56,500	56,500
3	**Kingsgate**	282,500	0	847,500
4	Fixed Demand Charge	($399,067)	($399,067)	($399,067)
5	Average Winter Kingsgate price	$7.59		$7.59
6	Factored price for peak days	$2.50		$2.50
7	Kingsgate midpoint	$18.98		$18.98
8	Volume of peaking	282,500		847,500
9		($5,761,529)	($399,067)	($16,486,454)
10				
11	**Alberta**			
12	Fixed Demand Charge	($5,052,513)	($5,052,513)	($5,052,513)
13	Mitigation Recovery	$3,299,600	$3,299,600	$3,299,600
14	Average Winter Kingsgate price	$7.59		$7.59
15	Factored price for peak days	$2.50		$2.50
16	Kingsgate daily midpoint	$18.98		$18.98
17	Redelivery Diversion Cost	$0.55		$0.55
18	Markup Cost (15%)	$2.85		$2.85
19	Total commodity cost	$22.38		$22.38
20	Volume of peaking	282,500		847,500
21		($6,322,207)		($18,966,620)
22	Total	$560,677	($399,067)	$2,480,166
23		$266,322	($189,557)	$124,008
24		47.5%	47.5%	5.0%
25				
26	Net Benefit (Cost)	**$200,773**		

The above evaluation indicates that Kingsgate peaking instead of BC Hydro SCP Peaking provides a $200 thousand net benefit to Terasen Gas Midstream for 2005/2006.

3.4 *Figure 14 in Appendix O on Page 141 refers to a maximum take-away capacity at EKE of 285.0 TJ/d. Please clarify whether this quantity includes the 50.3 TJ/d that is reserved for Northwest Natural.*

Response:

Yes, the maximum take-away capacity at EKE in Appendix O includes 50.3 TJ/d reserved for NWN.

3.5 *Page 67 states that the Base Case assumes the release of 54.0 TJ/d of Westcoast T-South capacity. Please provide the calculation that Terasen Gas used to estimate the avoided T-south tolls for the 2005/06 gas contract year that will result from the release of this capacity.*

Response:

The current toll for T-South Capacity is Cdn$0.306/GJ and this will remain in place until December 31, 2005. It is estimated that the Westcoast Energy ("WEI") T-south toll will increase about 25% to Cdn$0382/GJ for 2006. This estimated increase is based upon a number of factors including: level of de-contracting, level of Interruptible credits and increase in annual cost of service. Since the filing of the Midstream ACP the National Energy Board ("NEB") has approved an increase in TCPL Mainline's equity thickness to 36% which is 5% higher than WEI's current equity thickness of 31%. This may put further upward pressure on the WEI's COS. The figures below are represented in thousands of Cdn$.

2005 Rate $/TJ	=	54*61*$0.306	=	$1,007.9
2006 Rate $/TJ	=	54*304*$0.382	=	$6,270.9
Total avoided demand charge				$7,278.9

In addition to the reduction in demand charges there would also be savings with respect to fuel and commodity charges from WEI.

3.6 *As Terasen Gas is and seems likely to continue to be a major holder of firm capacity on the Westcoast system, it seems reasonable to assume that the cost savings that Terasen Gas initiates by releasing capacity will be significantly reduced as a result of a recalculation of Westcoast rates to recover such lost T-South revenue from remaining T-South customers including Terasen Gas. If Terasen Gas did not include an adjustment for this dilution of the benefit of releasing Westcoast capacity in the response to the proceeding question, please provide a calculation of the expected net benefit of releasing 54.0 TJ/d of Westcoast T-South.*

Response:

The net benefit to Terasen Gas of de-contracting the 54 TJ/d of T-South capacity is the $2 million/year indicated in the Midstream Plan. Terasen Gas did review and take into account the T-South de-contracting impact on its existing portfolio. Though the increased T-South demand charges will increase Terasen Gas' existing portfolio costs, this increase is offset by the decreased Westcoast tolls resulting from the reduced Westcoast expansion in 2003 referred to Terasen Gas' Reduced Build Option (Segmentation). Terasen Gas may also benefit from the decrease in Station 2 commodity demand premiums that result from the decreased firm demand at Station 2.

Westcoast's 2003 T-South 200 MMcfd expansion project was reduced to 84 MMcfd through optimization of turned back capacity and the Terasen Gas arrangements with respect to Kingsvale South capacity. These Terasen Gas arrangements included the turn back of 105 MMcfd of its T-South long haul capacity and acquisition of 105 MMcfd of Kingsvale South capacity and 50 MMcfd of Interior capacity. The reduced Westcoast expansion saved Terasen Gas Midstream about $0.01/GJ on its existing Westcoast capacity.

3.7 *On page 68, Terasen Gas states that on peak days, all of the Midstream's T-South Inland capacity is required to service the Inland load. Please confirm that Figure 14 on page 141 is representative of this situation, and also shows 63.3 TJ/d moving across SCP and down T-South from Kingsvale to Sumas.*

Response:

Yes. On a peak day, based on no supply disruptions and capacity constraints <u>all</u> of the T-South Interior and TCPL capacity is required to meet peak day demand in the Inland service area. Figure 14 on Page 141 does represent this situation by showing 63.3 TJ/d flowing across SCP and T-South Kingsvale on a peak day.

3.8 *Page 68 states that on normal days the Midstream can align stranded T-South Inland and Kingsvale south segments to effectively create T-South Station 2 to Sumas capacity. Please discuss whether this alignment means that gas cannot at the same time also move across SCP and on to Huntingdon. Does this effectively restrict the use of the equivalent bloc of SCP capacity to being a peaking resource that can only be used when T-South Inland capacity is needed for Inland deliveries?*

Response:

No. On normal days, the Midstream has the option to flow gas from Station 2 to Huntingdon using unutilized T-South Inland and Kingsvale South capacity, or move supply from Alberta to Huntingdon using SCP. However, if the full amount of Kingsvale South capacity (63.3 TJ/d) is used to align with T-South Inland, Alberta supply cannot, simultaneously, move across SCP to Huntingdon due to limited Kingsvale South capacity unless it flows on an Interruptible basis.

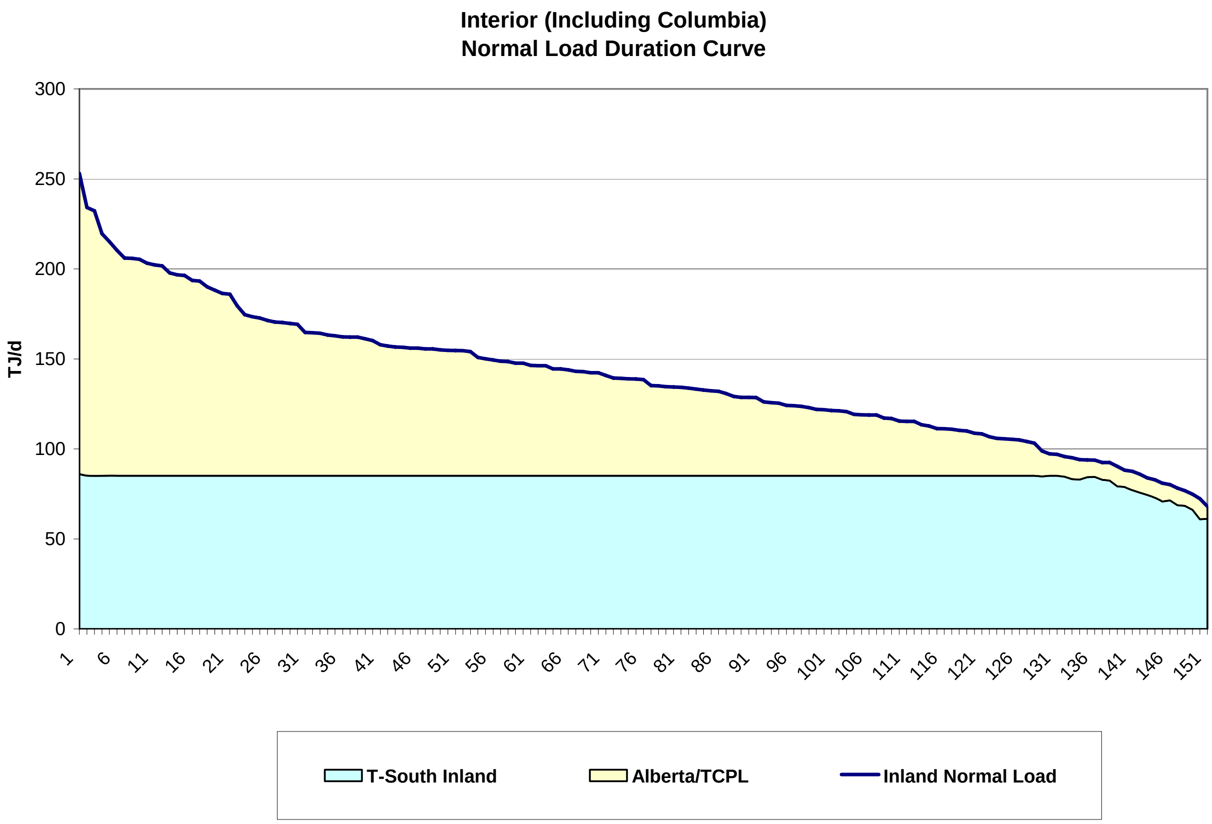
3.9 *Is there is an intermediate situation where SCP could be used to deliver gas from Kingsgate to the Interior while permitting the aligned use of T-South to continue? Put another way, how many days are there in a design and a normal winter when the Interior load could not be met without using the 54.1 TJ/d that is available from the Westcoast system at Kingsvale Please provide a load curtailment curve that supports the response.*

Response:

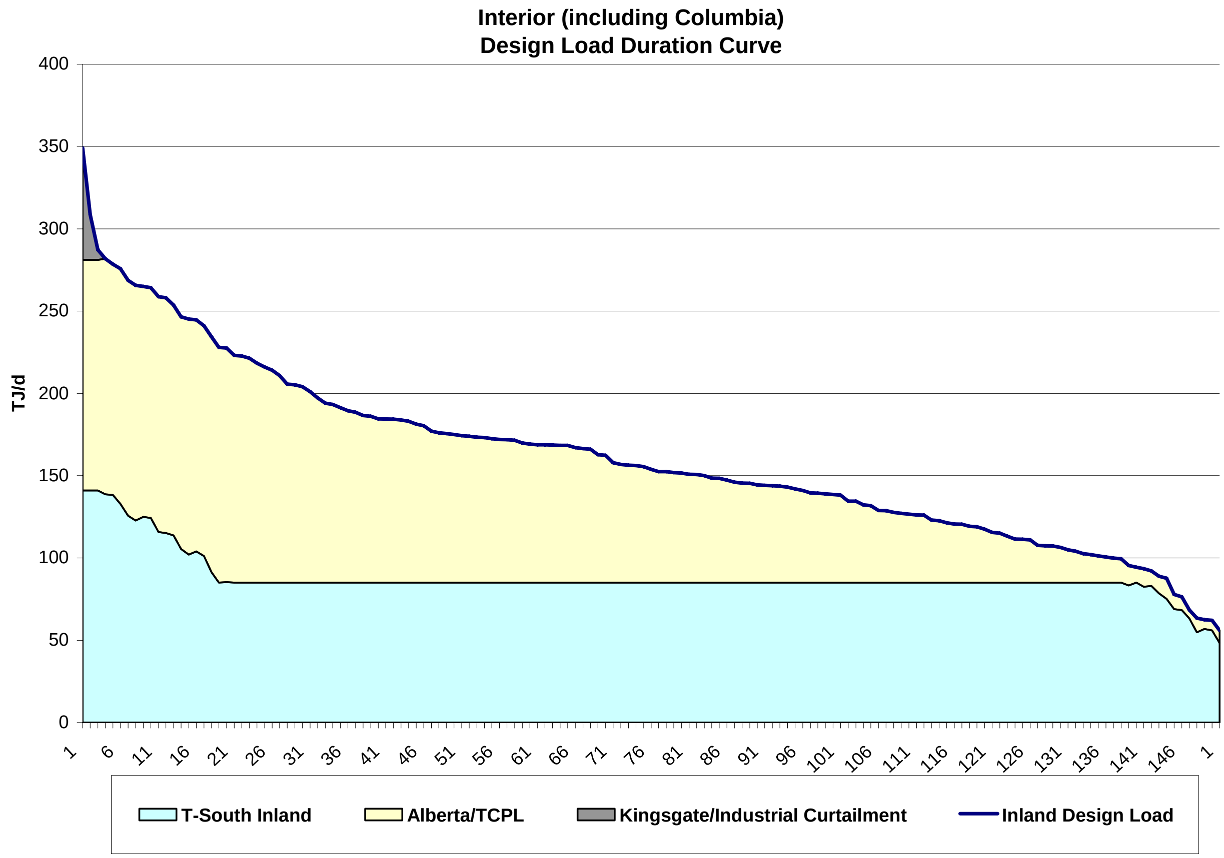
Segmentation allowed Terasen Gas to split 50 mmcfd of its exiting T-South long haul capacity into Interior capacity and Kingsvale South capacity and avoid a T-South expansion on Westcoast and increased Westcoast demand charges. The number of days that the 54 TJ/d of T-South Interior Capacity is required to meet Interior load requirements will depend on where the demand is in the Interior and the pricing at Station 2 and Alberta on the day. For this analysis Terasen Gas Midstream has assumed that the following priority of flows:

1. 87 TJ/d (141 TJ/d – 54 TJ/d) flows from Station 2 to the Interior via Westcoast Interior capacity.
2. 143 TJ/d flows from Alberta via TCPL capacity.
3. The remaining 54 TJ/d flowing from Station 2 to Interior via Westcoast Interior capacity.
4. Kingsgate seasonal/spot/peaking and Industrial Curtailment.

In a normal year scenario the 54 TJ/d of Westcoast Interior capacity could be used every day to flow supply to Huntingdon via Kingsvale South capacity. The chart below illustrates that by limiting the flows of Westcoast Interior capacity to 141 TJ/d (the Midstream's total Westcoast Interior capacity) less the 54 TJ/d, the flow via TCPL capacity is still able to meet Terasen Gas Midstream Interior load requirements in a normal year.



In a design year scenario approximately 15 days of the 54 TJ/d of the Westcoast Interior capacity or some portion thereof is required. The peaks associated with the T-South Inland area (bottom) in the chart below represent the number of days that the 54 TJ/d of Interior Capacity or a portion of the capacity is required to meet Interior load requirements.



3.10 *Please discuss whether the return of the BC Hydro SCP capacity was needed in order for the aligned use of T-South and the release of the 54.0 TJ/d of T-South capacity to be feasible.*

<u>Response:</u>

Yes, BC Hydro's SCP capacity was essential for the aligned use of Westcoast T-South capacity and the release of 54.0 TJ/d of T-South Long Haul capacity. Although Terasen Gas Midstream had access to SCP on days when BC Hydro left the capacity unutilized, BC Hydro maintained priority to the service as a firm shipper. Given BC Hydro's priority to the Kingsvale South capacity, Terasen Gas could not rely on the Kingsvale South capacity to meet normal or cold winter load requirements and would be exposed to undue risk. Without <u>firm</u> access to SCP transportation, Terasen Gas would not have de-contracted Westcoast T-South Long Haul capacity.

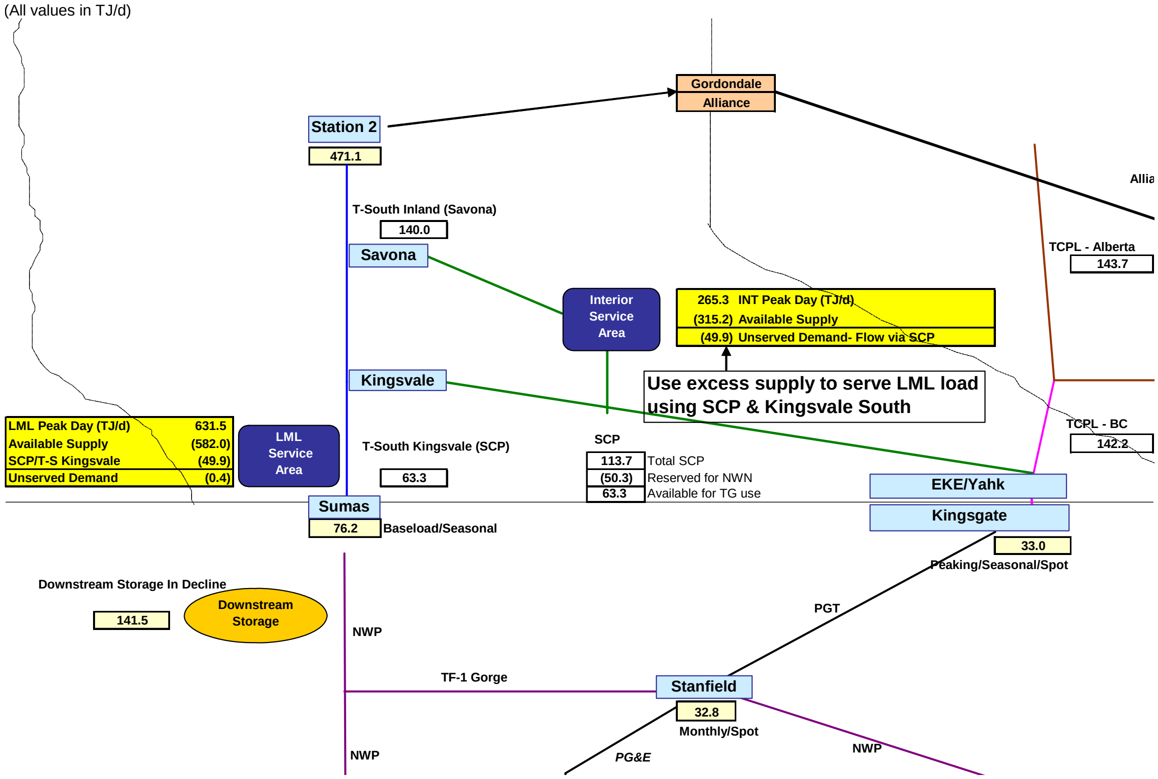
3.11 *As the situation with respect to T-south appears to be the same for the first 15 coldest days whether Terasen Gas is receiving BC Hydro peaking or is using the SCP capacity and sourcing peaking gas at Kingsgate,* *please outline the situation on the 16th coldest day and provide a diagram in the form of Figure 14 on page 141.*

<u>Response:</u>

The following are assumptions based on one scenario for the 16th coldest day and assumptions around downstream storage. As noted previously Sendout knows exactly when the peak day will occur so the model will look to optimize the amount of supply in storage to meet this peak day. In reality the Midstream group would not have this knowledge.

The scenario assumes that the Sumas price will be higher than the Kingsgate price and therefore the Kingsgate seasonal and the Alberta supply not being utilized for interior load would flow to Huntingdon via SCP/Kingsvale South capacity. It is also assumed that Stanfield supply would flow north on Gorge capacity in order to manage the downstream storage position to the extent that declines in storage deliverability required additional supply.

IR Response 3.11 (PUBLIC VIEWING)
Terasen Gas Midstream Portfolio
2005-06 Design Flows for 16th Day
Based on One Scenario
(All values in TJ/d)



Appendix C

BCGas™ NATURALLY RESOURCEFUL

Inland Pacific Connector

February 2001 Update

1

BCGas™ NATURALLY RESOURCEFUL

Inland Pacific Connector

2

NATURALLY RESOURCEFUL

Inland Pacific Connector (IPC) Project

- extends Southern Crossing from Oliver to Huntingdon
- increases capacity at Sumas market by 400 mmcfd
- target in-service date of November 2003
- Consists of
  - 610mm (24”) diameter X 246 km pipeline
  - 65,000 bhp compression at 3 locations
    - Kitchener or Yahk (existing site)
    - Trail (new site)
    - Midway (new site)
  - station modifications at Yahk, Oliver Y, Huntingdon

3

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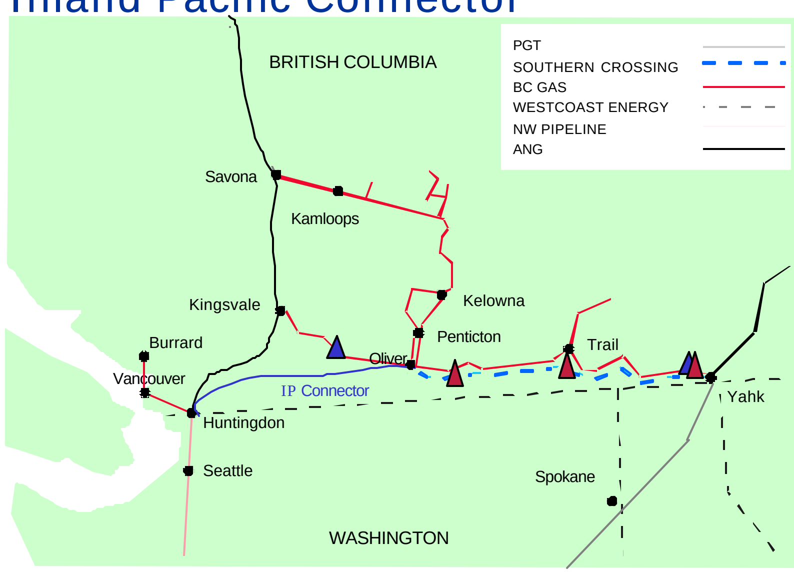
Inland Pacific Connector



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Why is new pipe needed?

- Regional growth is using up surplus in delivery capacity
- High demand for available capacity lead to price disconnection at Sumas
  - Nov - Jan experience is a warning sign
  - Capacity valued at far more than cost
- More power generation will be added to meet increasing B.C. and PNW demands
  - 2000+ MW of additions possible in next 3 years (400 mmcfd)

5

BCGas™ NATURA

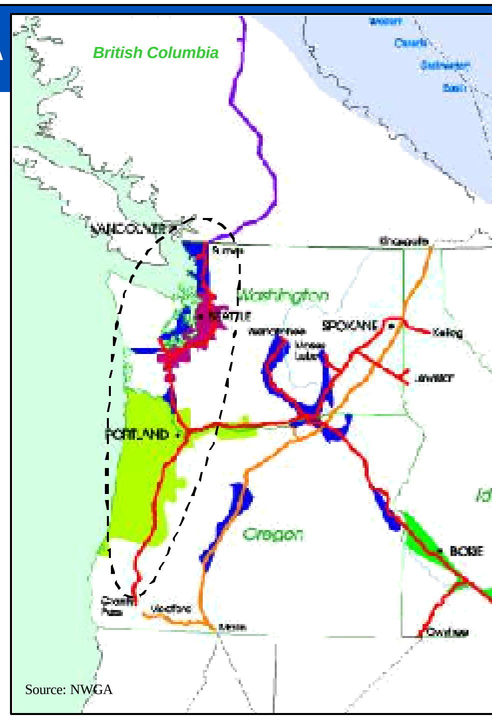
I-5 Corridor Region

Demand Grow driven by:

- LDC's (BC Gas, Centra, PSE, NWN, Cascade, Avista)
- BC Hydro
- PNW Power Generation

Supply Constrained by:

- Westcoast Capacity to Sumas
- NWP Gorge Capacity
- JPS Deliverability/Storage
- Mist Deliverability/Storage
- Other Peaking Resources



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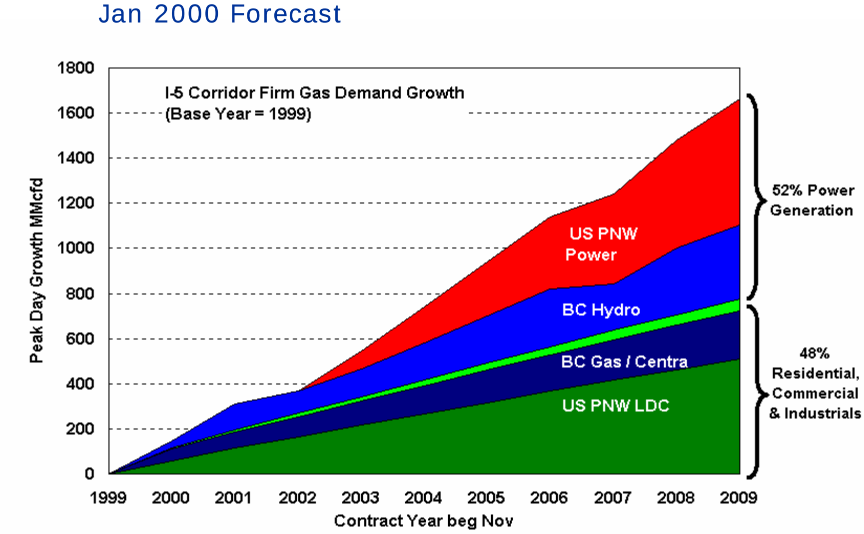
BCGas N A T U R A L L Y   R E S O U R C E F U L

Regional Gas Demand Growth
Jan 2000 Forecast



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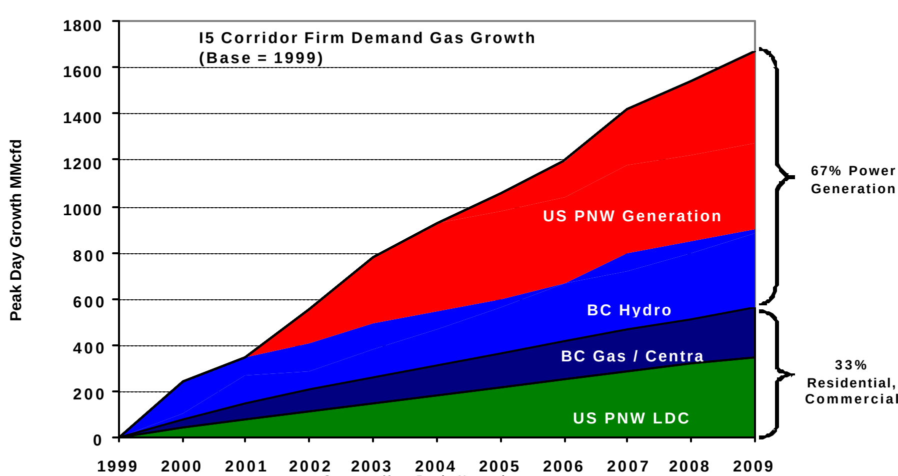
BCGas N A T U R A L L Y   R E S O U R C E F U L

Regional Gas Demand Growth
February 2001 Forecast (Low LDC Growth)



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Regional Gas-Fired Power Generation

Existing (3000 MW)

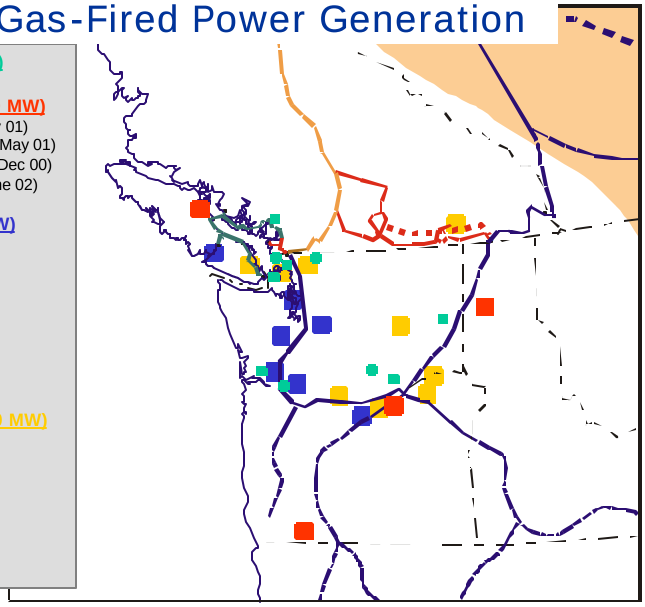
Construction (1500 MW)
Rathdrum 270 MW (Nov 01)
Klamath Falls 500 MW (May 01)
Island Cogen 240 MW (Dec 00)
Hermiston 500 MW (June 02)

Permitted (2600 MW)

Port Alberni	240 MW
Everett	250 MW
Fredrickson	250 MW
Chehalis	520 MW
Satsop	500 MW
Longview	320 MW
Coyote S2	250 MW
Centralia	250 MW

Development (4700 MW)

Duncan	600 MW
Sumas 2	600 MW
BP/Amoco	500 MW
Goldendale	250 MW
Starbuck	1100 MW
Umatilla	500 MW
Creston	1000 MW
Trail	150 MW



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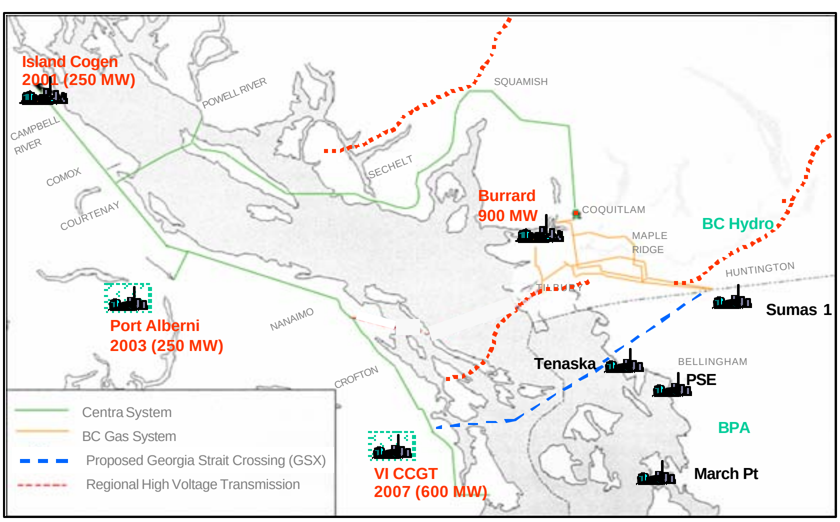
Gas Fired Power Generation - BC Hydro



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BC Gas

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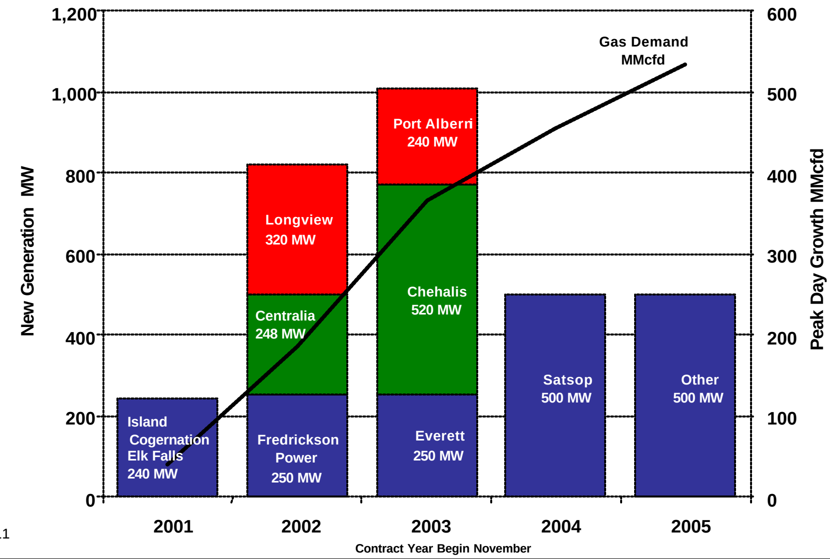
I5 Corridor Generation Projects



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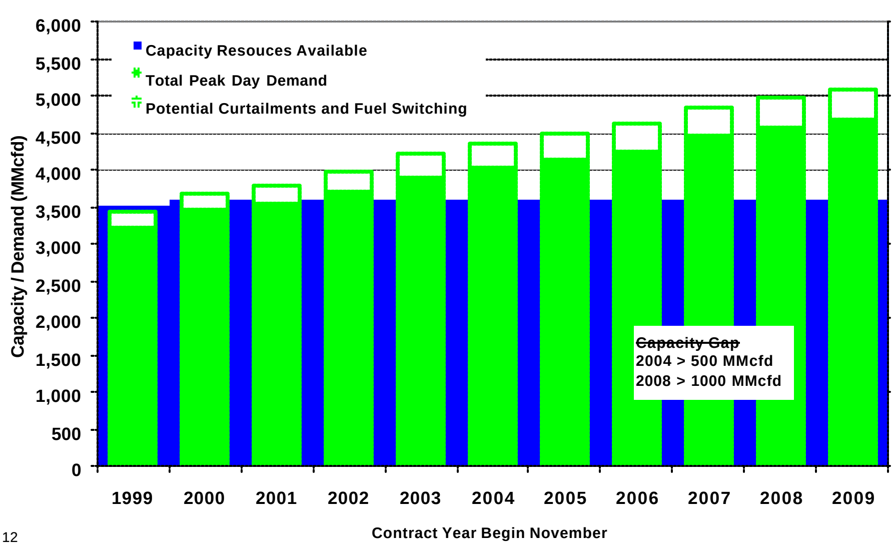
Regional Supply Resources



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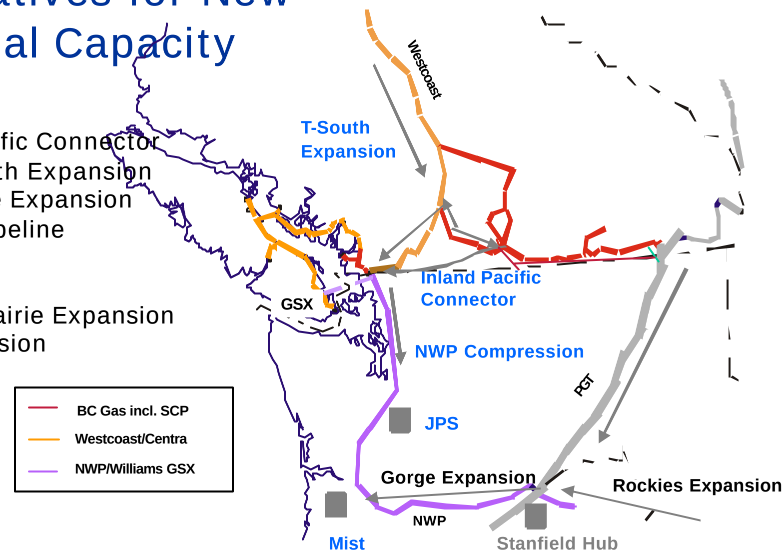
Alternatives for New Regional Capacity

Pipe
Inland Pacific Connector
WEI T-South Expansion
NWP Gorge Expansion
Vantage Pipeline

Storage
Jackson Prairie Expansion
Mist Expansion



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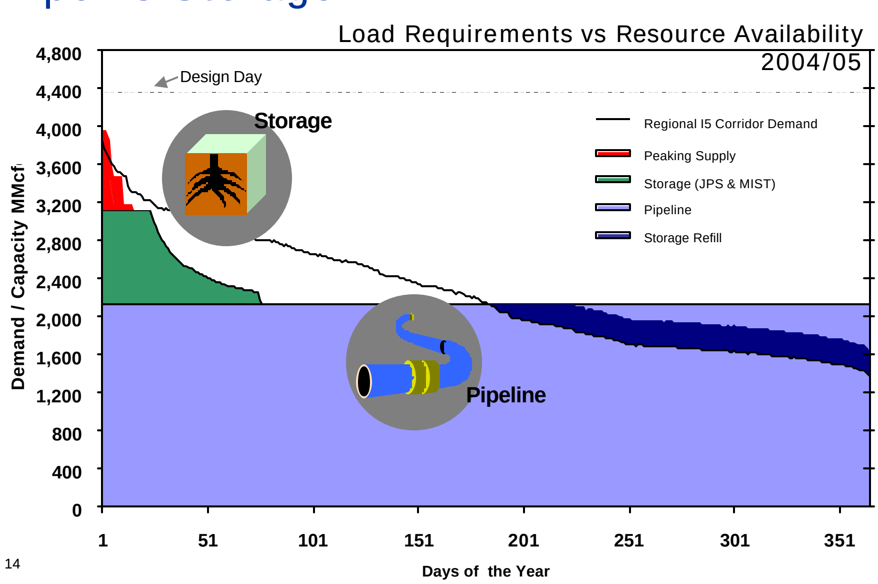
Pipe vs Storage



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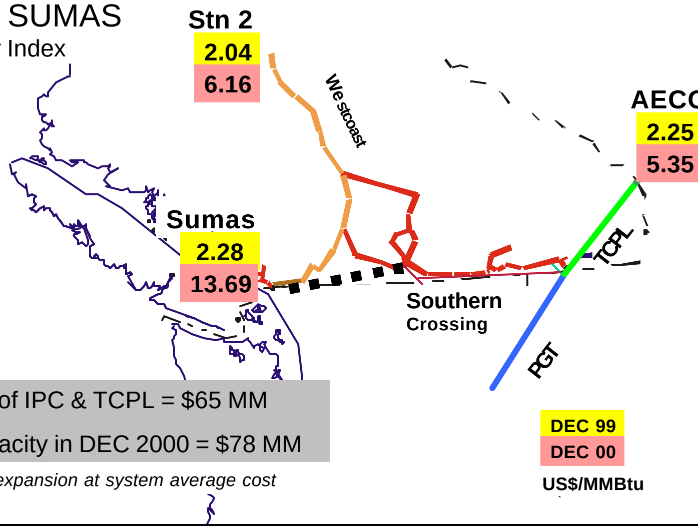
The Cost of Being Wrong

Insufficient Capacity causes price isolation

AECO vs SUMAS
Dec Monthly Index



Annual Cost of IPC & TCPL = $65 MM

Value of Capacity in DEC 2000 = $78 MM

Assumes TCPL expansion at system average cost

15

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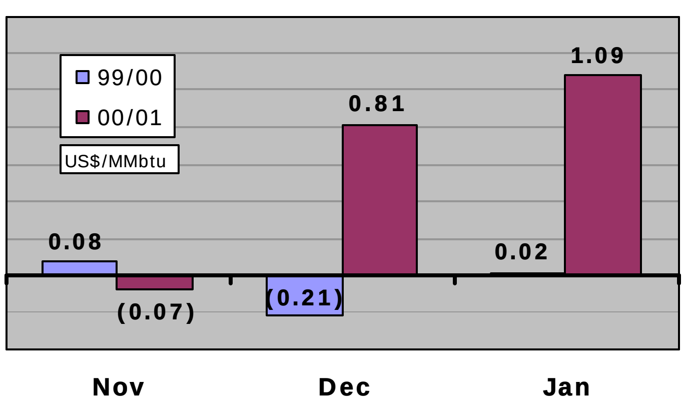
The Cost of Being Wrong

Cost of increased competition for limited supply

Stn 2 -AECO Differential



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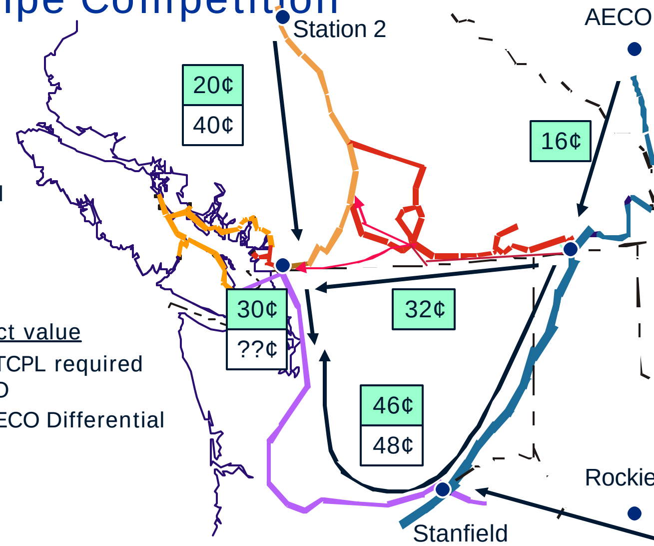
Pipe on Pipe Competition

$US/MMbtu

Rolled In

Incremental



Factors that impact value

- Expansion on TCPL required to access AECO
- Station 2 vs AECO Differential

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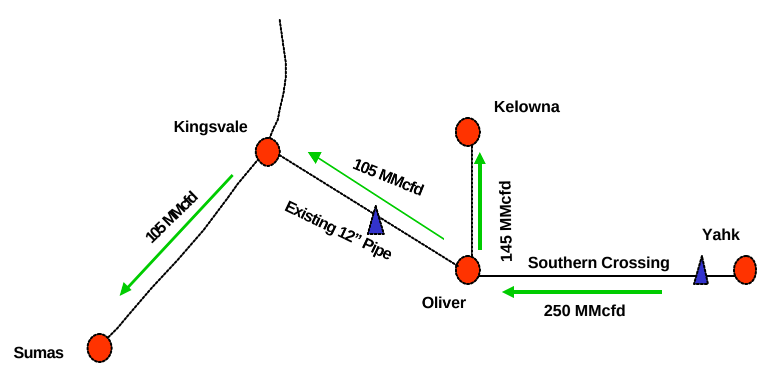
IPC Project Details

- SCP Initial Capacity 250 MMcfd (105 MMcfd to Sumas via Kingsvale)
- Compression additions could increase capacity on SCP
- Capacity on Oliver-Kingsvale line can not be increased further with hp
- To add new capacity to Sumas, a new pipe connection is required



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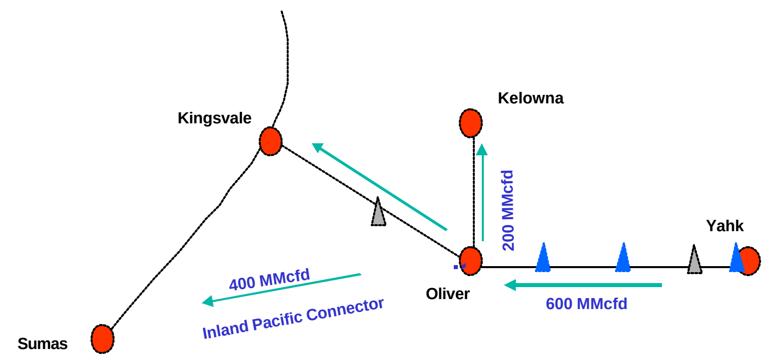
Inland Pacific Connector

- Throughput on SCP increased to 600+mmcfd through compression
- New 24" 1440# pipeline built from Oliver either direct to Huntingdon or to Kingsvale on Westcoast system
- Increases capacity from Yahk to Huntingdon from 105 to 400mmcfd
- Increases capacity at Sumas by 400 mmcfd



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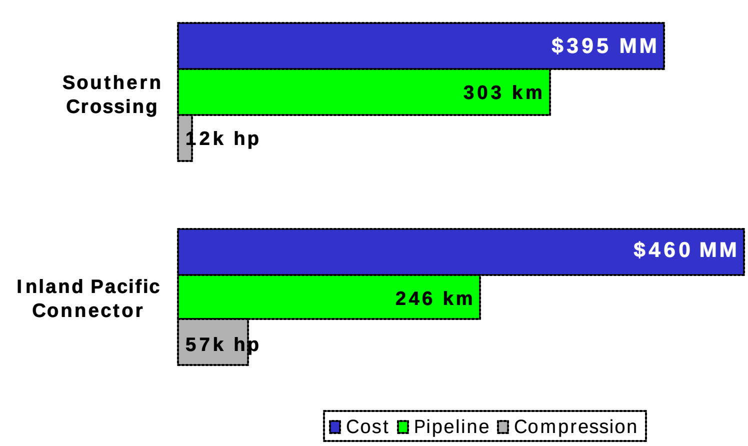
Inland Pacific Connector

Capital Cost Comparison of IPC to SCP
(Direct Costs)



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IPC Transportation Service

- In Service Nov 2003 or 2004
- Firm Transportation from Yahk to Huntingdon
- 300+ MMcfd of new capacity available
- 15 Year Terms
- Expected Toll US$0.32 - $0.38 /Mmbtu
- Request for Expressions of Interest April 2001
- Shipper Firm Commitments October 2001

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Development Schedule

Milestones

▪ Public Consultation Process Started	Feb 2001
▪ Open Season for Shipper Support	Jun 2001
▪ Shipper Agreements	Fall 2001

Project Execution

▪ Routing, Engineering, EIA	Mar-Sept 2001
▪ CEAA/EAO Application Submission	December 2001
▪ EAO and CEAA Approval	May 2002
▪ Access roads and logging/clearing	Jun-Nov 2002
▪ Construction Begins	May 2003
▪ In-Service Date	Nov 2003

To meet 2003 In-Service Date ALL routing, engineering, and EIA activities have to be completed during summer 2001 with permits available to allow access roads, clearing and logging to begin summer of 2002

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APPENDICES

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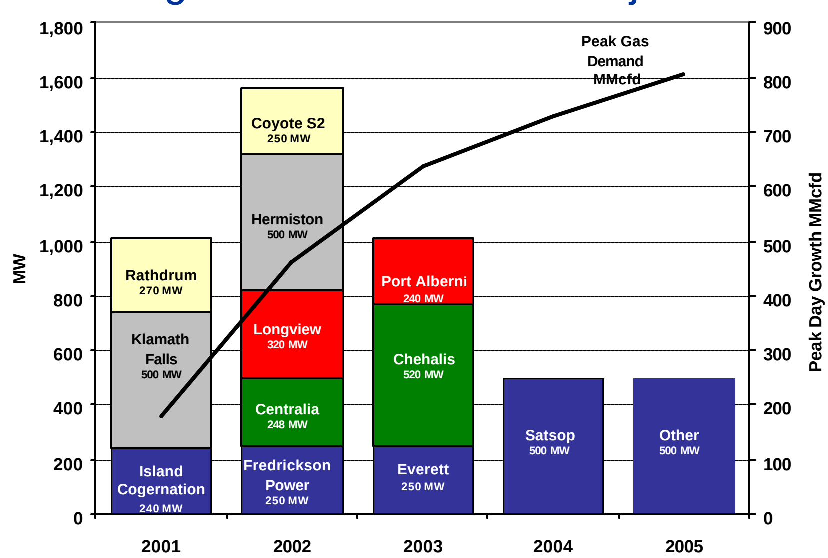
Regional Generation Projects



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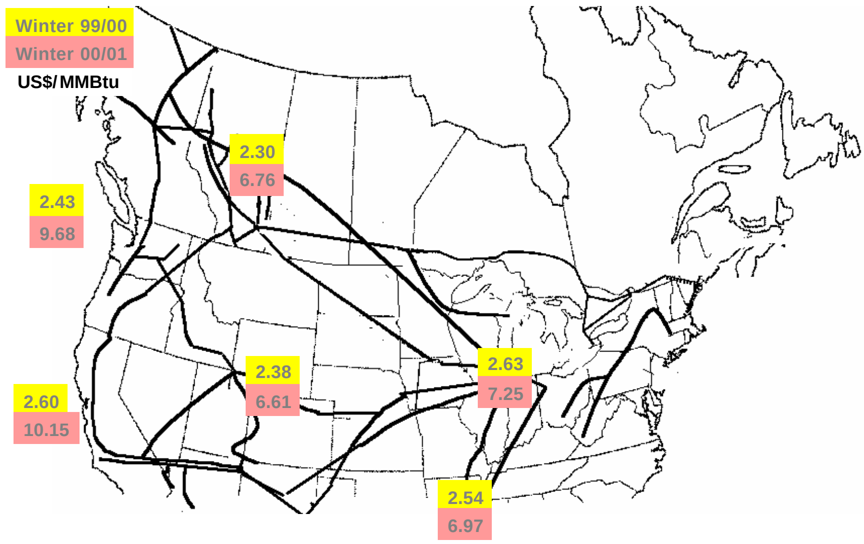
Comparison of Regional Winter Prices



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ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

LETTER NO. L-13-01

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

VIA FACSIMILE

March 15, 2001

Mr. David M. Masuhara
Vice President
Legal, Regulatory & Logistics
BC Gas Utility Ltd.
24th Floor, 1111 West Georgia Street
Vancouver, B.C. V6E 4M4

Dear Mr. Masuhara:

Re: Gas Markets in British Columbia in a North American Context

The unprecedented range of prices reported by the Sumas index has caused the B.C. Utilities Commission to investigate the factors impacting the price and the validity of the index as a price setting mechanism. On January 18, 2001, Commission staff sent out a request for information about the current natural gas market environment. BC Gas Utility Ltd., Centra Gas British Columbia Ltd., Pacific Northern Gas Ltd., British Columbia Hydro and Power Authority, Canadian Association of Petroleum Producers, Central Heat Distribution Limited, and Westcoast Energy Inc. responded. The response of each party was thoughtful and meaningful, and has assisted the Commission in its understanding of the situation and its consideration of further action.

The parties expressed generally consistent views about gas markets in British Columbia, and the reasons for the recent price disconnection at Sumas and in the western part of the continent. After reviewing the submissions, the Commission has developed the following view:

- Sumas Market and Indices

The infrastructure capabilities for delivering gas as well as supply/demand factors influence the natural gas price. Prices are tied to upstream market prices only when there is sufficient pipeline capacity for this linkage to take place. When there is a lack of capacity relative to demand, prices disconnect from northeastern British Columbia and Alberta and both commodity and transportation differentials exceed tolls from Station 2 to Sumas.

The value of the index is only as good as the information that is supplied by participants. It is unknown whether all buyers or sellers participate in the surveys since the information is confidential. The quantities represented reflect the buyer reporting a purchase and a seller also providing the quantity on the opposite side of the trade. However, the volumes surveyed for Sumas are among the highest volumes transacted for a market trading point if a comparison is made with Malin, Stanfield, Kingsgate and Station 2.

Price spikes are not a new phenomenon. Temporary high levels of peak demand have exceeded the capacity limits at Sumas resulting in temporary price spikes in the past. These short-lived situations have not been sufficient to drive the construction of capacity as the value of T-south varies both above and below the Westcoast Energy Inc. ("WEI") T-south toll throughout the year.

In conclusion, the market has limited supply availability as it is pipeline constrained. There are a small number of buyers and sellers with multiple sources of supply. In a constrained marketplace the highest bidder will capture the discretionary supplies that are made available.

- Station 2 Market and Indices

The monthly and daily Station 2 prices have a strong historical correlation with the Alberta Energy Company / Nova Inventory Transfer index. Each index reflects the same market forces along with similar short and long term arbitrage by traders and producers. However, Station 2 is not a robust monthly gas market although the daily market is very active.

- California Situation and the Effect on Pacific Northwest Market

There was a convergence of many factors in the Pacific Northwest that caused prolonged high prices at Sumas in late 2000. Precipitation was less than normal causing water levels at most reservoirs to be low. At the same time gas storage levels remained less than ideal as high prices encouraged gas to be withdrawn.

In conjunction with these factors the deregulation experiment in California has not stimulated the construction of electrical power plants and the state required substantial electricity supply to meet market demand. The colder than normal winter in northern California added to the convergence of negative factors and exacerbated the demand for electricity.

The electricity power generation suppliers in the Pacific Northwest were attracted to the high electricity prices in California. As a result, generation facilities powered by natural gas consumed large quantities of the fuel, driving the price up substantially as the marginal price of gas moved upward to be more aligned with high electricity prices in the region.

- Pacific Northwest Resource Balance

In recent months there have been several proposed pipeline and storage expansions that would impact the Pacific Northwest pipeline infrastructure. They will have both a positive and negative impact on Sumas capacity limitations. The overall impact of these initiatives should be assessed.

Northwest Pipeline held an open season for expansion of firm delivery capacity from Sumas to Chehalis, Washington. This drew interest for expansion of 200 MMcfd of take-away capacity from Sumas by July 2003. In addition Jackson Prairie operators are considering a 300 MMcfd expansion of the storage facility. Northwest Pipeline intends to install additional compression, increasing physical flow of gas northward along the Opal to Wyoming corridor, thereby reducing the requirement for operational flow orders. It is also expected that Pacific Energy Group will hold an open season seeking interest in expansion of 200 MMcfd of take-away capacity at Kingsgate, to be in service by the summer of 2002.

- Need for, and Viability of, Major Resource Additions

The majority of respondents suggested that market forces would determine the extent and timing of pipeline expansions. The prolonged price spike at Sumas this winter may now indicate that additional capacity at this junction is justified. This would be a change from the recent past, when the fixed costs of holding pipeline capacity outweighed the benefits. Many factors will determine the optimal pipeline addition, including WEI tolling on T-south transportation.

- <u>Need for High Level Integrated Resource Planning Initiative</u>

The majority of respondents expressed the view that a workshop or forum be conducted to gather information. All directly affected stakeholders could be invited with the objective of developing a collaborative solution to this issue.

The Pacific Northwest gas market area that includes southern British Columbia, covers parts of two nations and several states. Several regulatory agencies share jurisdiction, and no individual regulator has the responsibility, or the detailed knowledge, to carry out an overall energy resources planning function. There is broad support that market considerations drive resource additions, but there is also recognition that high level discussion of the current situation in the Pacific Northwest will assist in development of the optimal solutions.

BC Gas Utility Ltd. ("BC Gas") has offered to prepare a report on the natural gas resource balance in the Pacific Northwest region, and to organize a stakeholder discussion on the resource balance and possible alternative resource additions. The Commission is pleased to accept BC Gas' offer.

The Commission, therefore, directs BC Gas to undertake discussions on Regional Resource Planning according to the attached Scope of Discussions, with a full representation of stakeholders. Commission staff will be available to participate in the discussions as needed. The report is to be submitted to the Commission by June 29, 2001.

The Commission thanks each of the parties that provided responses on the issues impacting Sumas prices this past winter. Your submissions have assisted us in better understanding the dynamics of that market hub and the Regional Resource Planning Study will further assist the Commission in its oversight of gas purchasing practices of utilities in British Columbia.

Yours truly,

Original signed by:

Robert J. Pellatt

RB/mmc
Attachment
cc: Mr. Geoffrey Higgins
Manager, Regulatory Affairs
Centra Gas British Columbia Inc.
Mr. Craig P. Donohue
Director, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
Mr. Ray Aldeguer, Senior Vice President
Legal and Regulatory Affairs & General Counsel
British Columbia Hydro and Power Authority
Mr. Pierre R. Alvarez, President
Canadian Association of Petroleum Producers
Mr. John S. Barnes, President and General Manager
Central Heat Distribution Limited
Mr. Wayne Soper, Senior Vice President of External Relations
Westcoast Energy Inc.

British Columbia and Pacific Northwest

Regional Natural Gas Resource Planning

Scope of Discussions

---

* Definition of Regional Study Area
* Gas Demands in the Region
* Demand Growth, including Power Generation
* Natural Gas Resource Balance in the Region
* California Impacts on Demand and on Supply to the Region
* Supply Shortfalls on a Peak day, Seasonal and Annual basis
* Near Term Remedies
* Possible Resource Additions in the Longer Term
* Economic Justification for Adding Major Resources
* Proposed Actions to Develop Needed Resource Additions

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Regional Resource Planning Study – July 2001

Meeting Demand Growth in the I-5 Corridor Natural Gas Market

Prepared for The British Columbia Utilities Commission by BC Gas Utility Ltd.

ABSTRACT

The capacity of natural gas infrastructure supplying the I-5 corridor region of British Columbia, Western Washington, and Western Oregon is insufficient to meet forecast peak demand. Without additional capacity a base case capacity deficit of between 579 and 928 mmcf/d is expected by 2004. This expectation is based on the aggregate of demand forecasts developed for each of the region's major market sectors: local distribution company core customers, industrial, and generation. The forecast shows that natural gas-fired combined cycle generation projects represent a significant source of new regional demand growth that is expected to account for over half of the growth forecast for this decade. Analysis of regional demand under normal weather conditions indicates that pipeline capacity is the type of resource addition most suited to alleviate the regional capacity deficit.

During the winter of 2000/01 the California energy crisis resulted in increased demand for natural gas to fuel regional generation resources that were run to produce power for export to that state. The resulting competition for natural gas in the capacity- constrained market resulted in record-high regional gas prices. These conditions foreshadow the affect of the region's growing capacity deficit. Left unabated, growing regional demand will increase both the probability and consequence that similar market conditions will result from normal regional demand. To reduce the level and volatility of gas prices within this region, a positive supply margin must be restored. Additional infrastructure is required and the addition of this capacity should lead demand growth to avoid extreme gas prices.

The economic affect of these prices on secondary market consumers far outweighs the cost of the additional pipeline capacity required to insure against a reoccurrence of similar conditions. However, since most secondary consumers lack the financial capability to underwrite addition capacity and given the non-excludable nature of the benefit which it would provide, it is unlikely that the cost of this resource could be recovered on a full demand charge basis. An alternative to this traditional means of cost recovery therefore, is required.

Based on a review of natural gas markets in British Columbia and the reasons for the record-high prices that occurred at Sumas and other western trading points during the 2000/01 winter season, the British Columbia Utilities Commission directed BC Gas Utility Ltd. to undertake discussions on regional resource planning. This Study is intended to satisfy this directive and to initiate discussion among effected stakeholders.

The full text of the Study is available on the BC Gas website:
http://www.bcgas.com/download/Regional_Resource_Planning_Study.pdf

Or to request a copy to be mailed to you contact: Donna McGeachie
BC Gas Community Relations
E-mail: dmcgeachie@bcgas.com
Phone: 604-443-6553
Fax: 604-443-6900

October 2001

Appendix D

News Release

BCGas

BC GAS INC. • 1111 WEST GEORGIA STREET, VANCOUVER, B.C. CANADA V6E 4M4
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May 7, 2001 **For immediate release**

BC GAS CALLING FOR EXPRESSIONS OF INTEREST ON PROPOSED NEW PIPELINE

BC Gas is looking for companies interested in obtaining capacity to ship natural gas on its proposed new Inland Pacific Connector Pipeline.

The company today announced an open season on the proposed pipeline that would link the recently built Southern Crossing Pipeline in Oliver to the regional marketing hub in Huntingdon.

An "open season" is a process where interested parties can review the costs, terms and conditions for transportation service on the pipeline and decide if they want to make a commitment to purchase capacity on the line.

"This open season will help us determine the extent of the demand for additional natural gas in the Lower Mainland and U.S. Pacific Northwest and allow us to move ahead with public consultation and planning for the construction of the new pipeline," said Rich Ballantyne, BC Gas director of transmission and project development.

"Once built, the Inland Pacific Connector will increase the supply of natural gas to the Lower Mainland and help prevent dramatic price increases like those experienced last winter."

The 246-kilometre Inland Pacific Connector Pipeline and related facilities will cost approximately $495 million. Once regulatory approvals are obtained, BC Gas hopes to have the pipeline in service by late 2003.

Companies can e-mail BC Gas at ***ipc_info@bcgas.com*** to obtain an information package about capacity on the Inland Pacific Connector Pipeline.

BC Gas Utility Ltd. is the largest distributor of natural gas serving British Columbia, with 762,000 residential, commercial and industrial customers in more than 100 communities. BC Gas Utility Ltd. is a wholly-owned subsidiary of BC Gas Inc.

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For further information contact:
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INLAND PACIFIC CONNECTOR

BC Gas NATURALLY RESOURCEFUL

INLAND PACIFIC CONNECTOR
Open Season Summary

BC Gas is offering interested parties the opportunity to contract for firm transportation service from at or near the TransCanada Pipeline's (TCPL) interconnect at Yahk, British Columbia to the Huntingdon market hub.

The Open Season Procedures are detailed in the attached documents, however the major elements of the offering are summarised here. Please note that any request for service under the attached procedures is binding.

Description of Inland Pacific Connector Project:

- Construction of a new pipeline from Oliver to Huntingdon, British Columbia (approximately 246 km)
- Construction of new compression facilities on the Southern Crossing Pipeline between Yahk and Oliver, British Columbia
- Up to 9900 103m3/day or 350 mmcfd of new capacity will be available
- Anticipated in-service date of November 2003
- Open Season commences May 7, 2001 and closes June 7, 2001

Transportation Rates

- Based on contracted capacity of 350 mmcfd and capital cost of CDN$495 million (2001$s), including AFUDC, the initial year demand charge is estimated to be Cdn. $575 per month per 10^3m^3 of contracted capacity
- Assuming 100% utilisation of contracted capacity, the equivalent unit toll based on heat content of 1015 btu/scf and US/Cdn $ of 0.65 is approximately

  Cdn $0.53 per Mcf or

  US $ 0.34 per MMbtu
- Annual adjustments to the transportation charges will be made in accordance with cost of service methodology
- Interruptible capacity from Yahk to Huntingdon will be made available only to shippers contracting for firm capacity

- Fuel will be supplied in kind, and is expected to be 2% based on 100% utilisation of contracted capacity

Award of Capacity

- Capacity will be awarded to qualifying bidders who meet the criteria in the Open Season procedures, including the requirement for a minimum term of 15 years, as follows:
    - Existing shippers on the Southern Crossing Pipeline, BC Gas Utility, BC Hydro and PG&E Energy Trading, will be awarded in priority to new subscribers
    - Remaining capacity will then be awarded to other shippers on the basis of term, meaning that the shippers bidding the longest term will be awarded capacity first

Project Development Payments

- Based on total awarded capacity and any revised system design and cost estimates BC Gas will notify the awarded shippers of any change to the expected first year demand charge by July 15, 2001
- If the estimated first year demand charge is greater than Cdn. $655 per month (approximately Cdn $0.61 per mcf or US$0.39 per MMbtu), shipper will have a right to terminate its commitment for capacity at no cost effective July 31, 2001
- On August 1, 2001 all remaining shippers will be required to make a contribution toward the project development costs based on a prorata share of Cdn $3 million. For example, if shipper is awarded 25 mmcfd of a total of 350 mmcfd awarded capacity, the contribution would be Cdn $215,000

Upsteam Capacity Election

- Shippers can elect to make their request for service conditional on obtaining matching commitments for capacity upstream from Yahk
- If shipper can not obtain commitments for upstream capacity by October 15, 2001, BC Gas has the right to assign to the shipper any TCPL expansion capacity that it may have been able to arrange, else the shipper has right to terminate or reduce its commitment for capacity effective November 1, 2001
- If the shipper elects to terminate or reduce its commitment for capacity because it can not obtain upstream capacity directly or indirectly, it must make a payment equal to its prorata share of a further Cdn $3 million. For example if a shipper reduces its capacity by 10 mmcfd of a total of 350 mmcfd awarded capacity, the payment would be Cdn $86,000

Additional Rights to Terminate Capacity

- On November 15, 2001 BC Gas will notify the shippers of any change to the expected first year toll taking account any change in contracted capacity due to the unavailability of upstream capacity and revised system design and cost estimates
- If the estimated first year toll is greater than the higher of Cdn. $655 per month (approximately $0.61 per mcf or US$0.39 per MMbtu) or such number as may be agreed to by July 31, 2001, shipper will have a right to terminate its commitment for capacity effective November 1, 2001

Key Dates and Deadlines

A summary of the key dates and deadlines can be found in section 15 of the Open Season Procedures.

May 4, 2001

British Columbia Utilities Commission
600 – 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. W.J. Grant, Executive Director

Dear Mr. Grant:

Subject: Open Season on Inland Pacific Connector Project

Attached to this letter is an invitation being sent to prospective shippers to participate in an Open Season for capacity on the proposed Inland Pacific Connector ("IPC") project. As we have previously described, this project will consist of compression additions to the Southern Crossing Pipeline ("SCP") and construction of a new pipeline between Oliver, B.C. to Huntingdon, B.C. With upstream capacity, this new project is expected to provide more than 300 MMcfd of new, firm, directly connected capacity between Alberta market hubs and Huntingdon. BC Gas believes this project will provide a cost competitive alternative to existing pipeline systems to meet the growing needs for natural gas outlined in the Commission's letter of March 15, 2001, Gas Markets in British Columbia in a North American Context. While BC Gas is preparing a report on the natural gas resource balance and alternative resource additions, it is necessary to take the IPC project to the market at this time to test shipper interest in light of alternatives. BC Gas expects the determination from this process will provide further indication of the need for more capacity to the region to serve power generation and other demands.

Unless further consultative work and responses to the Open Season prove to the contrary, we expect this project to fall under provincial jurisdiction, and BC Gas to seek approvals from the Commission, the Environmental Assessment Office and the Oil and Gas Commission for the project. As well, we believe that the IPC project should be separated from BC Gas Utility Ltd.'s distribution assets and activities for various reasons including tax treatment, third party shipper interests, and delivery service rates to our existing customers. Pending determination of the aforementioned issues, we are proposing that BC Gas Inc. build the IPC project; however, language in the Open Season documents gives BC Gas the right to assign the project to other affiliates, including BC Gas Utility Ltd. Any decision would be dependent on serving the best interests of the utility customers, the shippers on SCP and IPC and BC Gas.

We are forwarding this Open Season package in advance of general distribution commencing on Monday, May 7. We ask that you hold this information in confidence until then.

Regardless of jurisdiction, a key element of this project requiring Commission approval is gaining access to Southern Crossing Pipeline for the installation of compression and transportation from Yahk to Oliver. In designing the project and Open Season, BC Gas has been guided by the following Key Principles:

- The effect of IPC must have a positive impact on the SCP cost of service paid by BC Gas Utility customers (other than capacity on IPC for which BC Gas customers subscribe)
- The use of SCP by IPC must preserve the rights and benefits attributed to SCP for BC Gas Utility customers
- IPC will provide means to reduce the cost of service of SCP

It is BC Gas' view that market and competitive positions make it necessary to offer IPC capacity to all interested parties at a rate based on the incremental costs of the new facilities. However, in order to meet the key principles, BC Gas is proposing several measures to deliver incremental value to its existing customers for underwriting SCP. We believe these measures will capture significant incremental benefits for existing customers, while making the IPC attractive enough for new shippers to underwrite the costs of the capacity additions so needed in the market.

We look forward to further discussing this exciting prospect to serve gas consumers in British Columbia and the region at the earliest opportunity.

Yours truly,

ORIGINAL SIGNED BY R.T. Ballantyne

R.T. Ballantyne
Director, Transmission and Project Development

BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

OPEN SEASON

May 7, 2001

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BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

A. OPEN SEASON

To: All Interested Parties

To meet the growing demands for natural gas in British Columbia and the U.S. Pacific Northwest, BC Gas Inc. ("**BC Gas**") is proposing the development of a new natural gas transmission project that will allow BC Gas to offer up to 9900 10^3m^3 per day (350 mmcfd) of firm transportation service from at or near the point of interconnection with the British Columbia pipeline system owned by TransCanada PipeLines Limited or any of its affiliates ("**TCPL**") at Yahk, British Columbia to the natural gas market hub at Huntingdon, British Columbia (the "**Inland Pacific Connector Project**"). The Inland Pacific Connector Project includes the construction by BC Gas of additional compression and related facilities on Southern Crossing Pipeline, owned by BC Gas' subsidiary, BC Gas Utility Ltd. ("**BCGUL**"), from Yahk to Oliver, British Columbia and of a new pipeline from Oliver to Huntingdon (the "**Inland Pacific Connector**").

BC Gas is conducting this Open Season to determine the level of interest in the Inland Pacific Connector Project. The Open Season Procedures discussed below (the "**Procedures**") describe the process by which interested parties may request firm transportation service on the Inland Pacific Connector Project ("**Requests for Service**") and the basis on which those Requests for Service will be evaluated and firm transportation service awarded.

B. OPEN SEASON PROCEDURES

1. Open Season Period

The Open Season for the Inland Pacific Connector Project commences at 8:00 a.m. Pacific Daylight Time ("**P.D.T.**") on May 7, 2001 and closes at 4:00 p.m. P.D.T. on June 7, 2001, subject to extension by BC Gas in its sole discretion at any time prior to the specified closing time (the "**Open Season Period**"). Subject to the other provisions in these Procedures, no Requests for Service will be received outside of the Open Season Period.

2. Description of Facilities

Subject to the terms of these Procedures, BC Gas is proposing the construction of new compressor stations on the Southern Crossing Pipeline (increasing the total installed compression by 65,000 horsepower) and of an approximately 246 kilometre, 610 mm Inland Pacific Connector from Oliver to Huntingdon. The Inland Pacific Connector will connect to the pipeline system of Huntingdon International Pipeline Corporation (which is owned by BC Gas), which in turn provides access to markets served at the Huntingdon hub, which include BCGUL's transmission and distribution system in the Lower Mainland, existing and proposed pipelines serving Vancouver Island, Northwest Pipeline Corp.'s pipeline system and other existing pipelines. The Inland Pacific Connector is anticipated to have a maximum operating pressure of 1440 psig and a delivery pressure at Huntingdon of 500 psig or higher. The final design, configuration, and cost of the Inland Pacific Connector Project will depend, in part, on the response to the Open Season.

3. Description of Services

BC Gas proposes to make firm transportation service available on Southern Crossing Pipeline and the Inland Pacific Connector for the transportation of up to 9900 10^3m^3 per day (350 mmcfd) of natural gas from Yahk to Huntingdon. Firm transportation service on the Inland Pacific Connector Project will be made available to qualifying interested parties for minimum 15 year and maximum 30 year terms on the following basis:

(a) BCGUL, British Columbia Hydro and Power Authority and PG&E Energy Trading, Canada Corporation, as existing shippers on Southern Crossing Pipeline ("**Existing Shippers**"), will have priority to subscribe for firm transportation service on the Inland Pacific Connector Project in relation to their existing contractual arrangements for firm transportation service on Southern Crossing Pipeline; and

(b) firm transportation service which is unsubscribed for after allowing for the rights of Existing Shippers will be made available to all other interested parties (including Existing Shippers subscribing for firm transportation service in excess of their rights as Existing Shippers) in accordance with the terms of these Procedures.

4. In-Service Date

(a) Firm transportation service on the Inland Pacific Connector Project is anticipated to commence as early as November 1, 2003. BC Gas will use reasonable efforts to obtain the necessary approvals to meet the proposed commencement date, but BC Gas reserves the right to delay that commencement date to such other date as BC Gas determines appropriate, having regard to the conditions set out in clause 11 hereof and such other matters as BC Gas in its sole discretion determines appropriate.

(b) If construction of the Inland Pacific Connector Project has not commenced on or before July 31, 2003, the Inland Pacific Connector Project and all contractual arrangements and undertakings with respect thereto shall terminate unless BC Gas and Shippers (as defined in paragraph 10(e) herein) agree in writing on or before that date to alternative arrangements.

5. Upstream Capacity

(a) In any Request for Service an interested party is required to indicate the amount of firm transportation service which is conditional (the "**Conditional Quantity**") on that interested party obtaining firm transportation service on TCPL's Alberta and British Columbia pipeline systems ("**Upstream Capacity**").

(b) Each Shipper shall use reasonable commercial efforts to obtain Upstream Capacity for the Conditional Quantity for a term commencing on the in-service date of the Inland Pacific Connector Project. On or before October 15, 2001, each Shipper stating a Conditional Quantity on its Request for Service shall provide written notice to BC Gas of the amount of the Conditional Quantity for which that Shipper does not waive its conditions. BC Gas then has the right, but not the obligation, to require a Shipper to enter into a Firm Transportation Upstream Capacity Agreement ("**FTUCA**") with BC Gas on or before October 31, 2001 for the amount of the Conditional Quantity not waived by that Shipper in its notice to BC Gas ("**Deficient Upstream Capacity**") or any portion thereof. The FTUCA provides that the Shipper will take an assignment of Upstream Capacity from BC Gas, in the form to which BC Gas has agreed, for any or all of the Deficient Upstream Capacity made available through BC Gas. Any Upstream Capacity made available by BC Gas shall commence on the in-service date of the Inland Pacific Connector Project and continue for the contract term stated in a Shipper's Request for Service.

(c) Each Shipper has the right, subject to making any payment required by paragraph 7(b), by written notice delivered to BC Gas on November 1, 2001 to reduce the maximum daily quantity specified in its Firm Transportation Precedent Agreement ("**FTPA**") with BC Gas by the portion of its Deficient Upstream Capacity for which BC Gas did not make Upstream Capacity available under a FTUCA.

(d) If, as a result of the reduction of the maximum daily quantity of firm transportation service by Shippers pursuant to paragraph 5(c), BC Gas in its sole discretion determines that the Inland Pacific Connector Project is no longer viable as proposed hereunder, BC Gas may terminate the project.

6. Transportation Rates

(a) BC Gas proposes to provide the firm transportation service described in these Procedures for a toll based on the cost of service methodology described in detail in Schedule A hereto.

(b) Based on the tolling methodology herein, BC Gas anticipates the initial year demand charge to be approximately Cdn. $575 per month per 10^3m^3 (in 2003 dollars), provided that contracted capacity for the Inland Pacific Connector is 9900 10^3m^3 per day (350 mmcfd). Assuming a 100% load factor, a heating value of 37.8 MJ/m^3 and a US$/Cdn.$ exchange rate of 0.65, the equivalent unit charge is calculated to be:

(i) Cdn. $0.53 per Mcf; or

(ii) US $0.34 per MMbtu.

The amounts in this paragraph 6(b) are estimates for informational purposes only.

(c) On or before July 15, 2001, BC Gas shall notify Shippers of the estimated initial year demand charge Shippers will be required to pay at the in-service date based on the Awarded Capacity (as defined in paragraph 10(e)), revised cost projections and the tolling methodology. If the demand charge estimated by BC Gas exceeds Cdn. $655 per month per 10^3m^3, then, if no other agreement can be reached by BC Gas and Shippers, each Shipper has the right to terminate the FTPA at no cost to that Shipper by written notice delivered to BC Gas on or before July 31, 2001.

(d) On or before November 15, 2001, BC Gas shall notify Shippers of the revised estimate of the initial year demand charge Shippers will be required to pay at the in-service date based on contracted capacity at the time of notice, revised cost projections and the tolling methodology. If the demand charge estimated by BC Gas exceeds the greater of Cdn. $655 per month per 10^3m^3 or the July 15, 2001 estimate, then, if no other agreement can be reached by BC Gas and Shippers, each of BC Gas and each Shipper has the right to terminate the FTPA by written notice delivered to the other party on or before November 30, 2001.

(e) The initial year demand charge calculated using the cost of service methodology in Schedule A will not exceed the greater of Cdn. $655 per month per 10^3m^3 or the amount specified in the notice given by BC Gas or otherwise agreed to pursuant to paragraph 6(d).

(f) If, as a result of the termination of any FTPAs by Shippers pursuant to paragraphs 6(c) or 6(d), BC Gas in its sole discretion determines that the Inland Pacific Connector Project is no longer viable as proposed hereunder, BC Gas may terminate the project. This termination right is in addition to the termination right given to BC Gas in paragraph 6(d).

(g) BC Gas will make interruptible transportation from Yahk to Huntington available only to those Shippers who have contracted for firm capacity on the Inland Pacific Connector Project, the revenues from which will be used to reduce the cost of service of Southern Crossing Pipeline and the Inland Pacific Connector Project.

7. Project Development Payments

(a) Each Shipper must pay to BC Gas in recognition of project development and other costs incurred by BC Gas with respect to the Inland Pacific Connector Project ("**Project Development Costs**") a payment on August 1, 2001 equal to that Shipper's pro rata share of Cdn. $3 million in Project Development Costs, to be calculated based on that Shipper's share of the greater of Awarded Capacity on that date or 9900 10^3m^3 per day.

(b) Each Shipper reducing any firm transportation service in accordance with the terms of paragraph 5(c) of these Procedures shall make a payment to BC Gas within seven (7) days of release of that capacity equal to the pro rata share of a further Cdn. $3 million, to be calculated based on the amount of firm transportation service reduced relative to the greater of 9900 10^3m^3 per day or Awarded Capacity for all Shippers on that date.

(c) All payments made pursuant to paragraphs 7(a) and (b) shall be applied to reduce the amount of capital costs to be added to the rate base in accordance with the tolling methodology.

(d) In the event the Inland Pacific Connector Project is terminated, any payments made pursuant to paragraphs 7(a) and (b) which were in excess of actual development costs, including, without limitation, cancellation costs for equipment, materials and services, of the Inland Pacific Connector Project shall be refunded to applicable Shippers in proportion to the pro rata payments made by such Shippers.

8. Requests for Service

(a) To request firm transportation service on the Inland Pacific Connector Project, each interested party must deliver by hand or courier any Request for Service in a sealed envelope within the Open Season Period to KPMG at the following address:

1209, 205 – 5th Avenue SW
Bow Valley Square II
Calgary, Alberta T2P 4B9
Attention: John Waiand.

KPMG will issue a receipt to the interested party as a confirmation that KPMG has received that Request for Service.

(b) KPMG will receive and hold unopened all Requests for Service until the close of the Open Season Period. Immediately upon the close of the Open Season Period, KPMG shall make a photocopy of all Requests for Service and forward those photocopies to BC Gas. KPMG shall retain the original Requests for Service, which shall be referred to only if KPMG is required by BC Gas or by an interested party (with respect to that interested party's Request for Service only) to verify the contents of any Request for Service.

(c) Each interested party may submit multiple Requests for Service. An interested party may withdraw any Request for Service at any time prior to the close of the Open Season Period. Once the Open Season Period is closed, no Requests for Service may be submitted or withdrawn.

9. Conditions on Requests

(a) To be considered for firm transportation service on the Inland Pacific Connector Project, each Request for Service shall include the following:

(i) Open Season Request Form: a fully completed and signed Open Season Request Form in the form attached as Schedule B hereto, including, without limitation, specification of the maximum daily quantity of firm transportation service, the minimum daily quantity of firm transportation service that would be acceptable in the event that pro-rationing of such service is required, the term in full years (adjusted to a November 1 contract year) and the quantity of firm transportation service requested which will be conditional on receipt of Upstream Capacity;

(ii) Upstream Capacity: if any or all of the firm transportation service requested by an interested party is conditional on receipt of Upstream Capacity, evidence that the interested party has requested Upstream Capacity for the Conditional Quantity; and

(iii) Credit Requirements: the credit information requested in Schedule C attached hereto and evidence of compliance with the credit requirements specified therein.

Failure of a Request for Service to comply with any of the foregoing conditions will result in the rejection of the Request for Service from that interested party.

(b) Notwithstanding anything else in these Procedures, the interested party's Open Season Request Form must specify that the firm transportation service is to commence on the in-service date of the Inland Pacific Connector Project and continue for a minimum term of fifteen (15) years (adjusted to a November 1 contract year) and a maximum term of thirty (30) years (adjusted to a November 1 contract year).

(c) Any interested party submitting a Request for Service shall by doing so agree to the following effective upon notification from BC Gas of Awarded Capacity:

(i) Firm Transportation Precedent Agreement: to execute and deliver within seven (7) days of receipt of notice of Awarded Capacity from BC Gas, an agreement with BC Gas in the form of the FTPA attached as Schedule D hereto;

(ii) Firm Transportation Upstream Capacity Agreement: to execute and deliver on or before October 31, 2001, to the extent required pursuant to paragraph 5(b) of these Procedures, an agreement with BC Gas in the form of the FTUCA attached as Schedule E hereto; and

(iii) Support in Proceedings: to support BC Gas in all proceedings, regulatory or otherwise, required by BC Gas to obtain the necessary approvals, licenses and permits to proceed with and complete the Inland Pacific Connector Project on terms and conditions similar to those set out in these Procedures, which support shall include both the provision of such information as BC Gas may reasonably request from time to time and appearing before and making and defending submissions to any regulatory or governmental body as directed by BC Gas.

(d) BC Gas will not accept changes to any terms or conditions in the FTPA or in the FTUCA or any conditions on the Requests for Service (other than as specifically permitted pursuant to these Procedures).

10. Award of Capacity

(a) If, after evaluating the Requests for Service, BC Gas determines to award firm transportation service on the Inland Pacific Connector Project pursuant to these Procedures, firm transportation service will be awarded in the following order to interested parties meeting the conditions in clause 9 and paragraph 10(d):

(i) Existing Shippers: Existing Shippers submitting Requests for Service will be awarded in priority to new subscribers firm transportation service on the Inland Pacific Connector Project in relation to Existing Shippers' existing contractual rights on Southern Crossing Pipeline; and

(ii) New Subscribers: all other interested parties (and Existing Shippers with respect to firm transportation service in excess of their rights as Existing Shippers) submitting Requests for Service will be awarded firm transportation service based on the contract term specified in the Open Season Request Form submitted by those interested parties, with interested parties requesting firm transportation service for the longest term awarded firm transportation service first, following in a descending order of contract term until all firm transportation service on the Inland Pacific Connector Project is awarded.

(b) If two or more interested parties otherwise entitled to be awarded firm transportation service pursuant to paragraph 10(a) submit Requests for Service with the same contract term and the unawarded firm transportation service is insufficient to satisfy the aggregate firm transportation service requested by those interested parties, firm transportation service will be awarded on a pro rata basis according to the amount of firm transportation service requested by each of those interested parties. If the firm transportation service to be allocated to an interested party is less than the minimum daily quantity specified in that interested party's Open Season Request Form, no firm transportation service will be awarded to that interested party.

(c) Notwithstanding anything else in this clause 10, BC Gas reserves the right to limit the amount of firm transportation service awarded to interested parties which do not have debt ratings for their long-term senior unsecured debt of BBB- or better by Standard and Poor's Rating Group (a division of McGraw-Hill, Inc.), or equivalent ratings by Moody's Investors Service, Inc. or Dominion Bond Rating Service, to 15% of the total amount of firm transportation service available on the Inland Pacific Connector Project.

(d) Prior to being awarded firm transportation service on the Inland Pacific Connector Project, interested parties must comply with the credit conditions specified in Schedule C attached hereto. If BC Gas, in its sole discretion, determines that, based on the financial information and assurances provided by an interested party and the requirements for credit specified in these Procedures, the creditworthiness of an interested party or any guarantor thereof is unsatisfactory, BC Gas may reject that interested party's Request for Service.

(e) On or before June 21, 2001, BC Gas will notify in writing each interested party awarded firm transportation service (each a "**Shipper**") of the amount of the firm transportation service awarded to that Shipper by BC Gas ("**Awarded Capacity**"), provided that BC Gas reserves the right to extend that time should circumstances require. In conjunction with that notification, BC Gas shall forward a FTPA to each Shipper for execution. The Shipper shall execute the FTPA in the form provided, without modification or amendment, and return the executed document to BC Gas within seven (7) days of receipt of notice of Awarded Capacity from BC Gas. Upon execution of the FTPA by Shipper and BC Gas, such agreement shall be binding on the parties thereto.

11. Conditions to Proceed

Any decision of BC Gas to proceed with the Inland Pacific Connector Project, even after any and all agreements required to proceed with the Inland Pacific Connector Project have been executed, shall be subject to obtaining the following:

(a) commitments from Shippers for firm transportation service on the Inland Pacific Connector Project which BC Gas determines in its sole discretion make the project desirable to proceed;

(b) all necessary regulatory and governmental approvals, licenses and permits from all interested regulatory and governmental bodies, including, without limitation, the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission, in form and substance satisfactory to BC Gas; and

(c) approval of the board of directors of BC Gas.

12. Reservations

(a) The Open Season, including these Procedures and the schedules to these Procedures, is provided to determine the level of interest among interested parties to firm transportation service on the Inland Pacific Connector Project. Neither the Open Season nor these

Procedures and the schedules hereto shall constitute an enforceable agreement. However, any Request for Service delivered by an interested party in accordance with these Procedures shall constitute a formal offer by that interested party to commit to firm transportation service on the Inland Pacific Connector Project and shall obligate that interested party to execute and deliver the FTPA, the FTUCA, if applicable, and any further documents which the FTPA and FTUCA require to be executed, including, without limitation, a firm transportation service agreement for the Inland Pacific Connector Project (a copy of which BC Gas will make available to interested parties at least one week prior to the close of the Open Season Period).

(b) To the extent that any or all firm transportation service on the Inland Pacific Connector Project is not subscribed for by interested parties submitting Requests for Service as a result of this Open Season or firm transportation service becomes available as a result of the provisions in paragraphs 4(b), 5(c), 6(c) or 6(d) of these Procedures or otherwise, BC Gas or any of its affiliates retains the right to subscribe for, or negotiate with any creditworthy party which it determines appropriate, in its sole discretion, for the subscription of, any or all of the unsubscribed firm transportation service, provided such subscription is on the terms and conditions specified in these Procedures as applicable to new subscribers.

(c) Notwithstanding anything else in these Procedures, BC Gas reserves the right, at any time, to not proceed with all or part of the Inland Pacific Connector Project (whether pursuant to paragraphs 4(b), 5(d) and 6(f) or otherwise), to not make any of the proposed firm transportation service available, to conduct additional open seasons, to determine the size, scope and cost of or to otherwise modify the Inland Pacific Connector Project, to select or reject Requests for Service on a non-discriminatory basis as BC Gas determines necessary to create an economically-viable project or to revive all or part of the Inland Pacific Connector Project to the extent it is previously terminated. Any such decisions by BC Gas shall be without liability for damages, costs or expenses by BC Gas to any interested party or any representative of that interested party.

13. Assignment

BC Gas has the right, at any time, to assign to an affiliate of BC Gas any or all of its rights and obligations with respect to the Inland Pacific Connector Project or these Procedures, including, without limitation, all rights and obligations under all FTPAs and FTUCAs.

14. Additional Information

Additional information with respect to these Procedures may be obtained from BC Gas' web site (www.bcgas.com) or by contacting the following person:

Cynthia Des Brisay
BC Gas Inc.
1111 West Georgia Street
Vancouver, British Columbia V6E 4M4
Facsimile: (604) 443-6476
e-mail: ipc_info@bcgas.com

15. Summary of Key Dates and Deadlines

May 7, 2001	Open Season commences at 8:00 a.m. P.D.T.
June 7, 2001	Open Season closes at 4:00 p.m. P.D.T. Requests for Service and all documents to be submitted in conjunction therewith are due prior to close.
June 21, 2001	All interested parties to be notified of Awarded Capacity on or before this date. FTPAs are sent to Shippers for execution at time of notice. Executed FTPAs must be returned to BC Gas within seven (7) days of notice of Awarded Capacity.
July 15, 2001	BC Gas to notify Shippers of anticipated initial year demand charge at in-service date.
July 31, 2001	First deadline for notice of termination due to excess initial year demand charges.
August 1, 2001	Initial Project Development Payments by Shippers are due.
October 15, 2001	Deadline for Shippers to waive any conditions related to Upstream Capacity.
October 31, 2001	Deadline for BC Gas and Shippers to enter into any FTUCAs required hereunder.
November 1, 2001	Deadline for notice of reduction of capacity due to lack of Upstream Capacity.
November 15, 2001	BC Gas to notify Shippers of revised estimate of anticipated initial year demand charge at in-service date.
November 30, 2001	Second deadline for notice of termination due to excess initial year demand charges.
July 1, 2002	Deadline for firm transportation service agreements to be executed and delivered by Shippers.
July 31, 2003	Termination date for Inland Pacific Project if construction not commenced and BC Gas and Shippers cannot agree to terms to continue the project.

SCHEDULE A

BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

TOLL METHODOLOGY

Subject to any incentive provisions that may be agreed to by Shippers and BC Gas, the following are the principles applicable to the calculation of delivery charges for firm transportation service on the Inland Pacific Connector Project:

1. The delivery charges will be calculated using straight fixed variable toll methodology based on the projected annual cost of service, as adjusted from year to year.

2. A demand charge will be calculated on a per unit of contracted capacity basis to provide for recovery of all of the fixed costs of providing firm transportation service on the Inland Pacific Connector Project. The major elements in determining the demand charge for firm transportation service are described as follows:

   (a) a rate base deemed to be financed with 70% debt and 30% equity.

   (b) a cost of debt calculated using a rate of interest equal to the weighted average of the interest rates applicable to the indebtedness incurred in relation to the Inland Pacific Connector Project.

   (c) a return on equity having a rate of 11%. Major capital additions made after the initial project will be at a rate agreed to by BC Gas and Shippers.

   (d) straight-line depreciation calculated at 3% per year.

   (e) a rate base which will include, among other things, actual capital costs and AFUDC. The estimated initial capital cost of the Inland Pacific Connector Project (in 2001 dollars) is Cdn. $495 million including AFUDC based on the system design described in the Procedures. AFUDC will be calculated based on the deemed capital structure and cost of capital provided for in subclauses (a), (b) and (c) hereof.

   (f) income taxes and all other taxes or government charges, fees and levies will be calculated on a flow-through basis and will be based on the notional tax payable rather than actual taxes paid.

(g) operating and maintenance costs associated with the provision of the firm transportation service. The estimated first year operating costs for the Inland Pacific Connector Project (in 2001 dollars) are Cdn. $5.8 million.

(h) other charges and expenses incurred as a result of the installation and operation of the Inland Pacific Connector Project including, without limitation, property taxes, large corporation taxes and other taxes or levies.

3. Shippers will pay a commodity charge which will recover all of those costs which vary with volumes of natural gas actually shipped. Commodity charges will include, without limitation, an amount for tax on fuel gas consumed in operations payable by BC Gas under the *Motor Fuel Tax Act* (British Columbia).

4. Shippers will be required to supply fuel in kind. Fuel requirements, including an allowance for lost and unaccounted for gas, will be based on a monthly forecasted rate, with variances recovered in subsequent months. The fuel rate is estimated to be 2% based on current configuration and 100% utilisation of the contracted capacity.

5. The demand charge will be calculated upon the basis of the sum of all contracted capacity on the Inland Pacific Connector Project for firm transportation service from Yahk to Huntingdon, British Columbia. Based on an expected contract capacity of 9900 10^3m^3 per day (350 mmcfd), the first year demand charge is expected to be Cdn. $575 per month per 10^3m^3 (estimated) of contracted capacity. Assuming 100% load factor, the equivalent average unit toll would be approximately Cdn. $0.53 per mcf or US $0.34 per MMbtu[1] (estimated).

6. To provide for some rate certainty, allowed capital costs to be added to initial rate base will be such that the initial year demand charge will not be in excess of the greater of Cdn. $655 per month per 10^3m^3 or the amount specified in the notice given by BC Gas or otherwise agreed to pursuant to paragraph 6(d) of the Procedures. Any excluded capital costs not included in initial rate base will be tracked in a deferral account. If in subsequent years the demand charge falls below the amount specified in this paragraph 6 as the maximum initial year demand charge, excluded capital costs will be added to the allowed rate base.

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1 Calculated based on 100% load factor, 0.65 US $/Cdn. $, 35.301 mcf/$10^3m^3$ and heat content of 1015 btu/scf.

SCHEDULE B

BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

OPEN SEASON REQUEST FORM

This Open Season Request Form is subject to the provisions in the Open Season Procedures dated May 7, 2001 prepared by BC Gas with respect to the Inland Pacific Connector Project.

Company Name: ______________________________

Mailing Address: ______________________________

____

Delivery Address (if different): ______________________________

____

Telephone: ______________________________

Fax: ______________________________

Contact Name: ______________________________

Title: ______________________________

Province or State of Incorporation: ______________________________

Guarantor, if applicable: ______________________________

REQUEST FOR SERVICE

Contract Term: ____________ years commencing on in-service date (adjusted to Nov. 1 year) (minimum 15 and maximum 30 years)

Maximum Daily Quantity ("MDQ"): ____________ 10^3m^3/day (not to exceed 9900 10^3m^3/day (350 mmcfd))

Minimum Daily Quantity: ____________ 10^3m^3/day (0 to MDQ)

Portion of MDQ Conditional on Upstream Capacity: ____________ 10^3m^3/day (0 to MDQ)

Request Form Submitted By:

Name: ______________________________

Title: ______________________________

Signature: ______________________________

Date: ______________________________

Please ensure the following information is attached to this Open Season Request Form:

1. **all credit information required pursuant to Schedule C to the Open Season Procedures; and**

2. **evidence of request for Upstream Capacity, if applicable.**

SCHEDULE C

BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

CREDIT REQUIREMENTS

All interested parties requesting capacity on the Inland Pacific Connector Project pursuant to the Procedures must attach to and submit to BC Gas along with the Open Season Request Form the following financial information to enable BC Gas to establish the creditworthiness of the interested party:

1. evidence of the interested party's (or its guarantor's, if applicable) debt rating for its long-term senior unsecured debt; and

2. audited financial statements of the interested party (or its guarantor, if applicable) for its two most recent fiscal years.

In addition to the foregoing information, BC Gas may request from the interested party (or its guarantor, if applicable), at any time prior to awarding capacity on the Inland Pacific Connector Project, such other financial information or assurances which BC Gas determines necessary to properly evaluate the creditworthiness of an interested party (or its guarantor, if applicable).

Where an interested party intends to qualify for credit through the provision of a guarantee provided by a third party, the guarantee must be in an amount sufficient to guarantee the obligations of that interested party to BC Gas having regard to the maximum daily quantity of gas and contract term specified in that interested party's Open Season Request Form and in the form of the Guarantee required by BC Gas. The guarantee must be executed and submitted to BC Gas along with the Open Season Request Form and such financial information with respect to the guarantor as the guarantor would be required to provide pursuant hereto if the guarantor was requesting capacity on the Inland Pacific Connector Project on its own behalf.

To be awarded firm transportation service on the Inland Pacific Connector Project, an interested party must:

(a) demonstrate that it (or its guarantor, if applicable) has a debt rating for its long-term senior unsecured debt of BBB- or better by the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.), Baa3 or better by Moody's Investors Service, Inc. or BBB or better by Dominion Bond Rating Service, provided that where the interested party (or its guarantor, if applicable) is rated by two or more such agencies and there are conflicting ratings, the lower rating prevails;

(b) if the interested party is unable to meet the criteria in (a) above, demonstrate that it has a credit quality at least equivalent to interested parties meeting the criteria in (a) above, in BC Gas' sole opinion; or

(c) provided financial security acceptable to BC Gas, in its sole discretion, having regard to the Request for Service submitted by that interested party.

If BC Gas determines that the creditworthiness or financial responsibility of the interested party (or its guarantor, if applicable) is unsatisfactory, BC Gas may request further financial information or financial security from that interested party (or its guarantor, if applicable) or reject that interested party's Request for Service. To the extent BC Gas requests any additional financial information or financial security, the interested party (or its guarantor, if applicable) shall provide the information or security within 5 days of the request. If, after the provision of that additional financial information or financial security, BC Gas determines the creditworthiness of an interested party (or its guarantor, if applicable) is unsatisfactory, or if that interested party (or its guarantor, if applicable) fails to provide that additional financial information or financial security within the time period specified, BC Gas may reject that interested party's Request for Service on the basis of unsatisfactory credit.

All financial information sent by interested parties or their guarantors will be treated as confidential by BC Gas and will be used strictly for the purpose of evaluating the creditworthiness of the interested parties or their guarantors.

Questions regarding BC Gas' credit requirements or other credit-related issues should be addressed to the following person:

David Bryson
BC GAS INC.
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4
Tel: (604) 443-6527
Fax: (604) 443-6929.

SCHEDULE D

BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

<u>FIRM TRANSPORTATION PRECEDENT AGREEMENT</u>

Please see form of agreement attached hereto

INLAND PACIFIC CONNECTOR PROJECT

FIRM TRANSPORTATION PRECEDENT AGREEMENT

BETWEEN

BC GAS INC.
("Transporter")

- and -

[●]
("Shipper")

JUNE [●] , 2001

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FIRM TRANSPORTATION PRECEDENT AGREEMENT

This Firm Transportation Precedent Agreement ("**Agreement**") is made as of June ______, 2001, by and between BC Gas Inc., a British Columbia corporation ("**Transporter**"), and ________________________ ("**Shipper**"), a ______________________ (collectively, the "**Parties**").

RECITALS:

WHEREAS Transporter initiated an Open Season on May 7, 2001 requesting interested parties to commit to contracting for firm transportation service from at or near the point of interconnection of the British Columbia pipeline system owned by TransCanada PipeLines Limited or any of its affiliates ("**TCPL**") at Yahk, British Columbia to the natural gas market hub at Huntingdon, British Columbia (the "**Inland Pacific Connector Project**"); and

WHEREAS the Inland Pacific Connector Project includes the construction by Transporter of additional compression and related facilities on Southern Crossing Pipeline, owned by Transporter's subsidiary, BC Gas Utility Ltd., from Yahk to Oliver, British Columbia and of a new pipeline from Oliver to Huntingdon ("**Inland Pacific Connector**"); and

WHEREAS Shipper has committed for firm transportation service on the Inland Pacific Connector Project for the maximum daily quantity and contract term specified in the Open Season Request Form attached hereto as Schedule A (the "**Request Form**");

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

1. Term

This Agreement shall become effective on the date of its full execution and shall continue in effect until: (i) the date of commencement of service under a firm transportation service agreement to be entered into between Transporter and Shipper with respect to firm transportation service for natural gas from Yahk to Huntingdon on terms consistent with those contained in this Agreement and the Request Form (the "**Firm Transportation Service Agreement**"), or (ii) the date that this Agreement is terminated pursuant to Paragraphs 11, 12 or 13 hereof.

2. Regulatory Approvals

(a) Subject to the terms and conditions of this Agreement, Transporter shall proceed with due diligence, having regard to the proposed in-service date of November 1, 2003, to apply for and obtain from all governmental and regulatory authorities having jurisdiction with respect to the Inland Pacific

Connector Project such authorizations and exemptions, and any necessary amendments or supplements thereto ("**Regulatory Approvals**"), including, without limitation, authorizations, permits and licenses from the British Columbia Utilities Commission ("**BCUC**") and the British Columbia Oil and Gas Commission ("**BCOGC**"), which Transporter determines are necessary to construct, own and operate the Inland Pacific Connector, to add the necessary compression to the Southern Crossing Pipeline, to provide the firm transportation service to Shipper contemplated herein and in any Firm Transportation Service Agreement and to perform Transporter's obligations pursuant to this Agreement and any Firm Transportation Service Agreement. Transporter reserves the right to file and prosecute any and all applications for such Regulatory Approvals (including the right at any time to withdraw any such application and or to reject any Regulatory Approval) and, if necessary, any court review, in such manner as it deems to be in its best interest.

(b) Subject to the terms and conditions of this Agreement, Shipper shall proceed with due diligence, having regard to the proposed in-service date of November 1, 2003, to apply for and obtain all Regulatory Approvals necessary for Shipper to construct and operate (or cause to be constructed and operated) any facilities necessary to enable Shipper to utilize the firm transportation services as contemplated herein and in any Firm Transportation Service Agreement and to perform Shipper's obligations pursuant to this Agreement and any Firm Transportation Service Agreement. Shipper reserves the right to file and prosecute any and all applications for such Regulatory Approvals (including the right at any time to withdraw any such application or to reject any Regulatory Approval) and, if necessary, any court review, in such manner as it deems to be in its best interest; provided that Shipper will not take any action which would obstruct, interfere with or delay the receipt by Transporter of the authorizations, permits, licenses or exemptions, and amendments or supplements thereto, contemplated hereunder, or otherwise jeopardize the Inland Pacific Connector Project.

3. Support in Proceedings

Shipper agrees to actively support and cooperate with, and not to oppose, obstruct or otherwise interfere with in any manner whatsoever, the efforts of Transporter to obtain Regulatory Approvals as contemplated in this Agreement, including, but not limited to: (i) the timely filing by Shipper of an intervention in support of Transporter's application for a Certificate of Public Convenience and Necessity ("**CPCN**"), (ii) the provision of any information reasonably requested by Transporter in preparing applications for Regulatory Approvals or any information required by the BCUC and BCOGC or any other governmental or regulatory body to be submitted during review of such applications, and (iii) the provision of any written evidence and witnesses as may reasonably be required by Transporter with respect to such Regulatory Approvals.

4. Design and Construction

Upon obtaining all necessary Regulatory Approvals, Transporter will proceed, subject to the continuing commitments of Shipper, with due diligence to complete the design of and construct the Inland Pacific Connector, add any necessary facilities to the Southern Crossing Pipeline and perform any other actions as are reasonably necessary to enable Transporter to provide the firm transportation service contemplated herein and in any Firm Transportation Service Agreement.

5. Credit Requirements

(a) As a condition precedent to receiving firm transportation service pursuant to this Agreement or any Firm Transportation Service Agreement, Shipper must meet one of the following creditworthiness requirements:

(i) Shipper, or a third party which guarantees all obligations of Shipper to Transporter under this Agreement and any Firm Transportation Service Agreement pursuant to a guarantee in the form required by Transporter (the "**Guarantor**"), must have a debt rating for its long-term senior unsecured debt of BBB- or better by the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) ("**S&P**"), Baa3 or better by Moody's Investors Services ("**Moody's**"), or BBB or better by Dominion Bond Rating Service ("**DBRS**"), provided that where two or more such agencies rate that entity, the lower rating prevails; or

(ii) Shipper shall provide to Transporter prior to or concurrent with the execution of this Agreement:

(A) an irrevocable, transferable, standby letter of credit issued by a commercial bank or financial institution located in Canada which is acceptable to Transporter and has a debt rating for its long-term senior unsecured debt of A or better by S&P, A2 or better by Moody's or A (low) or better by DBRS, provided that where two or more such agencies rate that entity, the lower rating prevails, and meeting Transporter's letter of credit requirements as set out in Schedule B hereto, in an amount equal to Transporter's estimate of the maximum demand tolls applicable to the firm transportation service to be provided pursuant to this Agreement or any Firm Transportation Service Agreement for a 12 month period, or

(B) such other security as Transporter determines acceptable.

(b) If at any time Transporter reasonably determines that the creditworthiness or financial responsibility of Shipper or its Guarantor, if appropriate, is unsatisfactory, Transporter may request further financial information or additional financial security from Shipper, or its Guarantor, if appropriate, as Transporter determines necessary. Shipper, or its Guarantor, if appropriate, shall provide such financial information or additional financial security within five (5) days of Transporter's request, failing which Transporter shall, in addition to all other rights it has pursuant to this Agreement or any Firm Service Transportation Agreement and otherwise pursuant to law, have the right to discontinue the firm transportation service contemplated hereunder and under any Firm Transportation Service Agreement, provided that Shipper shall be obligated to continue to pay all demand charges contemplated in this Agreement or any Firm Transportation Service Agreement.

6. Execution of Firm Transportation Service Agreement

Transporter and Shipper shall execute a Firm Transportation Service Agreement on or before July 1, 2002. If Transporter has not received and accepted a CPCN in form and substance acceptable to Transporter in its sole discretion or all Transporter's conditions precedent in Paragraph 11 have not been fulfilled or waived by such date, any of those conditions which remain outstanding shall be incorporated into the Firm Transportation Service Agreement. Notwithstanding any other provision of this Agreement, Transporter shall have the right to pursue any legal or equitable remedies available in respect of Shipper's breach of its obligation to execute a Firm Transportation Service Agreement by the date specified herein.

7. Project Development Payment

(a) Shipper hereby agrees to pay to Transporter, by certified cheque or electronic funds transfer, for project development and other costs incurred by Transporter with respect to the Inland Pacific Connector Project ("**Project Development Costs**"), a payment on August 1, 2001 equal to Shipper's pro rata share of Cdn. $3 million in Project Development Costs, to be calculated based on Shipper's maximum daily quantity specified in the Request Form relative to the greater of 9900 10^3m^3 per day or the aggregate total of maximum daily quantities for all shippers on that date.

(b) Shipper shall make a payment to Transporter, by certified cheque or electronic funds transfer, within seven days of reduction of any capacity pursuant to subparagraph 12(b), equal to the pro rata share of a further Cdn. $3 million, to be based on the amount of firm transportation service reduced by Shipper relative to the greater of 9900 10^3m^3 per day or the aggregate total of maximum daily quantities for all shippers on that date.

(c) All payments made pursuant to subparagraphs 7(a) and (b) shall be applied to reduce the amount to be added to the rate base in accordance with the tolling methodology should the Inland Pacific Connector Project proceed as described herein.

(d) In the event the Inland Pacific Connector Project is terminated, any payments made pursuant to paragraphs 7(a) and (b) which were in excess of actual development costs, including, without limitation, cancellation costs for equipment, materials and services, of the Inland Pacific Connector Project shall be refunded to Shipper in proportion to the pro rata payments made by Shipper, provided that Transporter shall have no other obligation to Shipper with respect to amounts paid by Shipper pursuant hereto.

8. Service

(a) Subject to satisfaction or waiver of the conditions set forth in Paragraph 11, firm transportation service under the Firm Transportation Service Agreement will commence on the date on which all facilities comprising the Inland Pacific Connector Project have been completed, tested and are available to provide the firm transportation service contemplated in this Agreement and any Firm Transportation Service Agreement (the "**In-Service Date**"). Subject to early termination in accordance with the terms of the Firm Service Transportation Agreement and to the renewal rights in Paragraph 9 hereof, the firm transportation service under the Firm Transportation Service Agreement will continue until October 31 of the last year of the term indicated on the Request Form.

(b) As of the In-Service Date, Transporter shall provide service to Shipper and Shipper shall be liable for and receive from Transporter the maximum daily quantity of firm transportation service specified in the Request Form, subject to the terms of this Agreement and the Firm Transportation Service Agreement.

9. Renewal Rights

Shipper shall have the right under the Firm Transportation Service Agreement to extend the term of that Firm Transportation Service Agreement for consecutive 2 year periods by providing written notice to that effect to Transporter not less than 24 months prior to the expiration of the term of that Firm Transportation Service Agreement or any renewal period with respect thereto, provided that in no event shall the term of the Firm Service Transportation Agreement, including any renewals thereof, exceed 30 years.

10. Tolls

(a) Shipper is responsible for the payment of tolls immediately upon the In-Service Date. Shipper shall pay to Transporter for each 10^3m^3 of firm transportation service provided by Transporter to Shipper a toll based on the cost of service methodology described in detail in Schedule C hereto. Shipper hereby agrees with the demand charge design methodology set forth herein and Shipper agrees to support the demand charge toll methodology related to this Agreement before the appropriate regulatory authorities having jurisdiction.

(b) Shipper will pay the initial year demand charges and any subsequent changes to those demand charges that occurs from time to time, provided that allowed capital costs to be added to initial rate base will be such that Shipper will not be responsible for the payment of any portion of a demand charge in excess of the greater of Cdn. $655 per month per 10^3m^3 or the amount specified in the notice given by Transporter or otherwise agreed to pursuant to subparagraph 12(c) for a period of 12 months from the In-Service Date.

(c) To the extent Shipper renews the Firm Transportation Service Agreement for one or more 2 year terms, the toll for such renewal periods shall be based on the toll methodology set out herein plus any additional costs incurred by Transporter as a result of any renewal.

11. Transporter's Conditions Precedent

Notwithstanding the execution of this Agreement by the Parties, Transporter's obligations under this Agreement or any Firm Transportation Service Agreement are subject to the following conditions precedent, which conditions are for the sole benefit of Transporter and may be waived by Transporter, in whole or in part, in the manner provided in this Agreement:

(a) <u>Regulatory Approvals</u>: Transporter's receipt and acceptance of all Regulatory Approvals in form and substance satisfactory to Transporter in Transporter's sole discretion;

(b) <u>Contractual Rights</u>: procurement of all necessary rights of way, easements or other property or contract rights necessary to the construction, ownership and operation of the Inland Pacific Connector Project and the provision of transportation service for Shipper contemplated in this Agreement and in any Firm Transportation Service Agreement, all in form and substance satisfactory to Transporter in Transporter's sole discretion;

(c) <u>Economic Viability</u>: the execution by other shippers of Firm Transportation Precedent Agreements and Firm Transportation Service Agreements providing for transportation service consisting of daily quantities sufficient to support the construction and operation of the Inland Pacific Connector Project on an economic basis acceptable to Transporter in Transporter's sole discretion; and

(d) <u>Board Approval</u>: the approval of the Board of Directors of Transporter to commit to the Inland Pacific Connector Project proceeding.

All Regulatory Approvals required by this Agreement must be duly granted by the governmental or regulatory authority having jurisdiction and must be final and no longer subject to rehearing or appeal; provided, however, that Transporter may waive the requirement that any such Regulatory Approval be final and no longer subject to rehearing or appeal.

If by July 1, 2002, any of the conditions set forth in this Paragraph 11 have not been met, waived or extended by the Transporter, then Transporter shall have the right to terminate this Agreement on thirty (30) days' written notice to Shipper and this Agreement shall terminate effective upon expiration of such thirty (30) day period and shall thereafter be of no further force and effect.

12. Shipper's Rights

(a) If Transporter notifies Shipper on or before July 15, 2001 that the estimated initial year demand charge which Shipper will be required to pay at the In-Service Date is greater than Cdn. $655 per month per 10^3m^3, then, if no other agreement can be reached by Transporter and all shippers, Shipper has the right at no cost to Shipper to terminate this Agreement by written notice delivered to Transporter on or before July 31, 2001.

(b) On or before October 15, 2001, Shipper shall notify Transporter whether or not Shipper waives any or all conditions stated on its Request Form with respect to the amount of firm transportation service which is conditional (the "**Conditional Quantity**") on Shipper obtaining firm transportation service on TCPL's Alberta and British Columbia pipeline systems ("**Upstream Capacity**"). On or before October 31, 2001, Transporter may require Shipper to enter into a Firm Transportation Upstream Capacity Agreement ("**FTUCA**") with Transporter in the form required by Transporter for any or all of the Conditional Quantity not waived by Shipper on or before October 15, 2001. Provided Shipper has used reasonable commercial efforts to obtain such Upstream Capacity and enters into any FTUCA required by Transporter within the time periods specified above, Shipper may, by notice to Transporter on November 1, 2001, reduce its maximum daily quantity of firm transportation service by an amount up to that portion of Shipper's Conditional Quantity not waived by Shipper or made available by Transporter pursuant to a FTUCA, subject to making any payment required pursuant to Paragraph 7. If Shipper reduces the maximum daily quantity it is required to take on the Inland Pacific Connector Project in accordance with the foregoing, neither Party shall have any rights or obligations to each other with respect to that quantity, other than the making of any payments by Shipper which are required pursuant to Paragraph 7. Subject to the foregoing, Shipper has no right to reduce its maximum daily quantity pursuant to this Agreement or any Firm Transportation Service Agreement.

(c) If Transporter notifies Shipper on or before November 15, 2001 that the revised estimated initial year demand charge which Shipper will be required to pay at the In-Service Date is greater than the greater of Cdn. \$655 per month per 10^3m^3 or the July 15, 2001 estimate, then, if no other agreement can be reached by Transporter and all shippers, each Party has the right to terminate this Agreement by written notice delivered to the other Party on or before November 30, 2001.

13. Termination of Agreement

(a) If construction of the Inland Pacific Connector Project has not commenced on or before July 31, 2003, this Agreement shall terminate unless Transporter and Shipper and all other shippers agree in writing on or before that date to alternative arrangements.

(b) If, pursuant to rights of shippers on the Inland Pacific Connector Project to reduce the maximum daily quantity of firm transportation service pursuant to terms consistent with subparagraph 12(b) hereof, Transporter, in its sole discretion, determines that the Inland Pacific Connector Project is no longer viable as proposed hereunder and terminates the project, this Agreement shall immediately terminate.

(c) In the event this Agreement is terminated pursuant to paragraph 11, paragraph 12 or this paragraph 13, Transporter shall not be liable for damages, costs or expenses to Shipper or any of Shipper's representatives as a result of the termination contemplated herein. Subject to subparagraph 7(d), Transporter shall be entitled to retain for its own use and at its own discretion any amounts paid by Shipper to Transporter with respect to the Inland Pacific Connector Project and Shipper shall have no rights with respect to such payments, whether or not Transporter proceeds with a like or similar project at a later date.

14. Representations and Warranties

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

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

(c) Shipper represents and warrants that it currently has the financial capacity to satisfy its obligations under this Agreement and, at the time it enters into the Firm Transportation Service Agreement, will be able to satisfy the requirements of the Transporter with respect to credit requirements in the manner provided herein.

15. Assignment

(a) Transporter, without obtaining any approvals or consents from Shipper, may assign this Agreement or any rights arising under this Agreement to any affiliate of Transporter.

(b) Shipper has the right to assign its rights and obligations, or parts thereof, under this Agreement provided any assignee complies with the credit requirements in Paragraph 5 hereof and Shipper obtains the prior written consent of Transporter to the assignment, which consent shall not be unreasonably withheld.

(c) 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 Agreement.

(d) The restrictions on assignment contained in this Paragraph 15 shall not in any way prevent either Party from pledging or mortgaging its rights hereunder as security for its indebtedness, and Shipper hereby agrees, in connection with any collateral assignment made by Transporter for financing of the Inland Pacific Connector Project, to:

(i) execute and deliver, as soon as reasonably practical, a consent and agreement and opinion of counsel satisfactory to Transporter and in conformance with the terms of Transporter's financing commitments; and

(ii) provide any other information reasonably required by financial institutions providing financing for the Inland Pacific Connector Project.

16. Notices

Notices under this Agreement shall be in writing and shall be sent by personal delivery or facsimile to the address and facsimile number designated below:

Transporter: BC GAS INC.
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4
Attention: Business Leader, Project Development
Fax No.: (604) 443-6953

And a copy to: BC GAS INC.
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4
Attention: Legal Services
Fax No.: (604) 443-6789

Shipper: Name of Shipper: ______________________________

Address: ____________________________________

____

Contact Person: _______________________________

Fax No.: _____________________________________

Notices given hereunder shall be deemed to be received when delivered by hand or courier if delivered by personal delivery or, if delivered by facsimile, on the business day immediately following the day on which the facsimile was delivered (with transmission confirmed). Either Party may change its address by written notice to that effect to the other Party.

17. Miscellaneous

(a) This Agreement sets forth all understandings and agreements between the Parties respecting the subject matter hereof, and all prior agreements, understandings and representations, whether written or oral, respecting the subject matter hereof are merged into and superseded by this Agreement.

(b) This Agreement may only be amended by an instrument in writing executed by both Parties.

(c) This Agreement, and any actions, claims, demands or settlements hereunder shall be governed by and construed in accordance with the laws of British Columbia and the federal laws of Canada applicable therein, without reference to any conflicts of law principles which might require the application of the laws of any other jurisdiction, and the Parties hereby irrevocably attorn to the exclusive jurisdiction of the courts therein.

(d) This Agreement and the obligations of the Parties hereunder are subject to all applicable laws, regulations, rules and orders of all governmental and regulatory bodies having jurisdiction.

(e) Any provision of this Agreement that is prohibited or unenforceable under the laws of British Columbia shall be ineffective and severed to the extent of the prohibition or unenforceability without invalidating or rendering unenforceable the remaining provisions hereof.

(f) A waiver by either Party of any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

(g) Shipper agrees to execute and deliver all such other and additional instruments and documents and to do such other acts as may be reasonably necessary to effectuate the terms and provisions of this Agreement.

(h) The terms, conditions and provisions of this Agreement shall be considered to have been prepared through the joint efforts of both Parties and shall not be construed against either Party as a result of the preparation or drafting thereof.

(i) This Agreement shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

(j) The obligation of Shipper to make any payment pursuant to Paragraph 7 hereof shall survive termination of this Agreement.

(k) This Agreement may be executed in counterpart and by facsimile, and if executed in that manner, such counterparts and facsimile signatures shall constitute one and the same instrument as if the Parties had executed the same document. Each Party executing a counterpart of this Agreement shall deliver one executed copy of that counterpart to the other Party.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in counterparts by their proper officers duly authorized as of the first date hereinabove written.

BC GAS INC.	**[Shipper]**
By: ______________________	By: ______________________
Print Name: ________________	Print Name: ________________
Title: ______________________	Title: ______________________

SCHEDULE A

REQUEST FORM

This Open Season Request Form is subject to the provisions in the Open Season Procedures dated May 7, 2001 prepared by BC Gas with respect to the Inland Pacific Connector Project.

Company Name: ______________________________

Mailing Address: ______________________________

____

Delivery Address (if different): ______________________________

____

Telephone: ____________________ Fax: ____________________

Contact Name: ____________________ Title: ____________________

Province or State of Incorporation: ______________________________

Guarantor, if applicable: ______________________________

REQUEST FOR SERVICE

Contract Term: ____________________ years commencing on in-service date (adjusted to Nov. 1 year) (minimum 15 and maximum 30 years)

Maximum Daily Quantity ("MDQ"): ______________ 10^3m^3/day (not to exceed 9900 10^3m^3/day (350 mmcfd))

Minimum Daily Quantity: ______________ 10^3m^3/day (0 to MDQ)

Portion of MDQ Conditional on Upstream Capacity: ______________ 10^3m^3/day (0 to MDQ)

Request Form Submitted By:

Name: ____________________ Title: ____________________

Signature: ____________________ Date: ____________________

Please ensure the following information is attached to this Open Season Request Form:

1. **all credit information required pursuant to Schedule C to the Open Season Procedures; and**

2. **evidence of request for Upstream Capacity, if applicable.**

SCHEDULE B

LETTER OF CREDIT REQUIREMENTS

A letter of credit must meet the following requirements:

1. Currency

The letter of credit must be payable in immediately available funds in Canadian dollars.

2. Term

The term of the letter of credit must be for a minimum length of one year and must be such that the letter of credit does not expire less than 60 days after the end of the last month during which firm transportation service is provided pursuant to this Agreement or the Firm Transportation Service Agreement. This may be accomplished through an automatic renewal provision, provided that it is specified that the issuer will provide 90 days' written notice to Transporter in the event that the letter of credit will not be renewed. In the event notice is given that a letter of credit will not be renewed, either a substitute letter of credit complying with the terms herein or other security satisfactory to Transporter will be provided to Transporter at least 10 days prior to the expiration of the letter of credit for which the notice of non-renewal was given.

3. Beneficiary

The letter of credit must state the beneficiary to be "BC Gas Inc.". The letter of credit must provide that Transporter may draw upon the Letter of Credit in an amount (up to the face amount for which the letter of credit has been issued) that is equal to all amounts that are due and owing from Shipper but have not been paid to Transporter within the time allowed for such payments under this Agreement or the Firm Transportation Service Agreement.

4. Account Party

The name on the Letter of Credit shall be the same as the name on the Request Form.

5. Reimbursement

The terms of the letter of credit must include a requirement for immediate reimbursement to the issuer upon honouring of a request for drawing under the letter of credit.

6. Condition to Drawings

Drawings are conditional on delivery of drawing certificate which certifies that Transporter is entitled to payment of a specified amount under the transportation contract. The form of drawing certificate should provide that proceeds of drawings shall be payable to Transporter or as Transporter may direct. Partial drawings must be permitted. To the extent the issuer fails to honour Transporter's properly documented request to draw on an outstanding letter of credit or otherwise fails to comply with the terms herein, either a substitute letter of credit complying with the terms herein or such other security acceptable to Transporter will be provided to Transporter within 2 days after such refusal.

7. Transferability and Irrevocability

The letter of credit must clearly state that it is "transferable" and "irrevocable".

SCHEDULE C

TOLL METHODOLOGY

Subject to any incentive provisions that may be agreed to by all shippers and Transporter, the following are the principles applicable to the calculation of delivery charges for firm transportation service on the Inland Pacific Connector Project:

1. The delivery charges will be calculated using straight fixed variable toll methodology based on the projected annual cost of service, as adjusted from year to year.

2. A demand charge will be calculated on a per unit of contracted capacity basis to provide for recovery of all of the fixed costs of providing firm transportation service on the Inland Pacific Connector Project. The major elements in determining the demand charge for firm transportation service are described as follows:

   (a) a rate base deemed to be financed with 70% debt and 30% equity.

   (b) a cost of debt calculated using a rate of interest equal to the weighted average of the interest rates applicable to the indebtedness incurred in relation to the Inland Pacific Connector Project.

   (c) a return on equity having a rate of 11%. Major capital additions made after the initial project will be at a rate agreed to by Transporter and all shippers.

   (d) straight-line depreciation calculated at 3% per year.

   (e) a rate base which will include, among other things, actual capital costs and AFUDC. The estimated initial capital cost of the Inland Pacific Connector Project (in 2001 dollars) is Cdn. $495 million including AFUDC based on the system design for the Inland Pacific Connector Project. AFUDC will be calculated based on the deemed capital structure and cost of capital provided for in subclauses (a), (b) and (c) hereof.

   (f) income taxes and all other taxes or government charges, fees and levies will be calculated on a flow-through basis and will be based on the notional tax payable rather than actual taxes paid.

   (g) operating and maintenance costs associated with the provision of the firm transportation service. The estimated first year operating costs for the Inland Pacific Connector Project (in 2001 dollars) are Cdn. $5.8 million.

(h) other charges and expenses incurred as a result of the installation and operation of the Inland Pacific Connector Project including, without limitation, property taxes, large corporation taxes and other taxes or levies.

3. All shippers will pay a commodity charge which will recover all of those costs which vary with volumes of natural gas actually shipped. Commodity charges will include, without limitation, an amount for tax on fuel gas consumed in operations payable by Transporter under the *Motor Fuel Tax Act* (British Columbia).

4. All shippers will be required to supply fuel in kind. Fuel requirements, including an allowance for lost and unaccounted for gas, will be based on a monthly forecasted rate, with variances recovered in subsequent months. The fuel rate is estimated to be 2% based on current configuration and 100% utilisation of the contracted capacity.

5. The demand charge will be calculated upon the basis of the sum of all contracted capacity on the Inland Pacific Connector Project for firm transportation service from Yahk to Huntingdon, British Columbia. Based on an expected contract capacity of 9900 10^3m^3 per day (350 mmcfd), the first year demand charge is expected to be Cdn. $575 per month per 10^3m^3 (estimated) of contracted capacity. Assuming 100% load factor, the equivalent average unit toll would be approximately Cdn. $0.53 per mcf or US $0.34 per MMbtu[1] (estimated).

6. To provide for some rate certainty, allowed capital costs to be added to initial rate base will be such that the initial year demand charge will not be in excess of the greater of Cdn. $655 per month per 10^3m^3 or the amount specified in the notice given by Transporter or otherwise agreed to pursuant to subparagraph 12(c) of the Agreement. Any excluded capital costs not included in initial rate base will be tracked in a deferral account. If in subsequent years the demand charge falls below the amount specified in this paragraph 6 as the maximum initial year demand charge, excluded capital costs will be added to the allowed rate base.

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1 Calculated based on 100% load factor, 0.65 US $/Cdn. $, 35.301 mcf/$10^3m^3$ and heat content of 1015 btu/scf.

SCHEDULE E

BC GAS INC.

INLAND PACIFIC CONNECTOR PROJECT

FIRM TRANSPORTATION UPSTREAM CAPACITY AGREEMENT

Please see form of agreement attached hereto

INLAND PACIFIC CONNECTOR PROJECT

FIRM TRANSPORTATION UPSTREAM CAPACITY AGREEMENT

BETWEEN

BC GAS INC.
("Transporter")

- and -

[●]
("Shipper")

October ●, 2001

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FIRM TRANSPORTATION UPSTREAM CAPACITY AGREEMENT

This Firm Transportation Upstream Capacity Agreement ("**Agreement**") is made as of October ______, 2001, by and between BC Gas Inc., a British Columbia corporation ("**Transporter**") and _________________________, a __________________ corporation ("**Shipper**") (collectively, the "**Parties**").

RECITALS:

WHEREAS Transporter initiated an Open Season on May 7, 2001 requesting interested parties to commit to contracting for firm transportation service from at or near the point of interconnection of the British Columbia pipeline system owned by TransCanada PipeLines Limited or any of its affiliates ("**TCPL**") at Yahk, British Columbia to the natural gas market hub at Huntingdon, British Columbia (the "**Inland Pacific Connector Project**"); and

WHEREAS the Inland Pacific Connector Project includes the construction by Transporter of additional compression and related facilities on Southern Crossing Pipeline, owned by Transporter's subsidiary, BC Gas Utility Ltd., from Yahk to Oliver, British Columbia and of a new pipeline from Oliver to Huntingdon ("**Inland Pacific Connector**"); and

WHEREAS, pursuant to that Open Season, Shipper indicated on its Request for Service that a certain amount of firm transportation service was conditional (the "**Conditional Quantity**") on Shipper obtaining firm transportation service on TCPL's Alberta and British Columbia pipeline systems ("**Upstream Capacity**"); and

WHEREAS Shipper failed to waive conditions with respect to, Upstream Capacity for some or all the Conditional Quantity on or before October 15, 2001; and

WHEREAS Transporter hereby agrees to make available to Shipper and Shipper hereby agrees to take from Transporter Upstream Capacity in the quantity and for the term set out in Schedule A attached hereto;

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

1. Term of Agreement

This Agreement shall become effective as of the date of its full execution and shall continue in effect until the earlier of: (i) the date of commencement of firm transportation service pursuant to an assignment agreement for the assignment of Upstream Capacity from Transporter to Shipper consented to by TCPL (the "**Assignment Agreement**"), or (ii) the later of the date of termination of a firm transportation precedent agreement between Transporter and Shipper with respect to the Inland Pacific Connector Project ("**FTPA**") or a firm transportation service agreement between Transporter and Shipper with respect to the Inland Pacific Connector Project ("**FTSA**"), if applicable.

2. Assignment of Upstream Capacity

(a) Subject to the conditions set out in this Agreement, Transporter and Shipper agree to enter into an Assignment Agreement for Upstream Capacity from TCPL and for the quantity and term provided in Schedule A hereto, and having such terms and conditions as Transporter prescribes and to which TCPL consents (the "**Assignment**").

(b) The Parties shall enter into the Assignment within seven (7) days of the execution of a firm transportation service agreement by Transporter and TCPL. The Assignment shall be effective as of the date executed by the Parties and consented to by TCPL (the "**Effective Date**").

3. Transporter's Obligations

Transporter shall use reasonable commercial efforts to:

(a) obtain firm transportation service from TCPL on terms consistent with those set out in a firm transportation precedent agreement between Transporter and TCPL; and

(b) obtain from TCPL the necessary consent to the Assignment.

4. Shipper's Obligations

(a) On and after the Effective Date, Shipper agrees to be solely responsible for the Upstream Capacity assigned by Transporter to Shipper pursuant to the Assignment.

(b) Shipper shall enter into any agreements with and take such other actions and do such other things as TCPL requires to consent to the Assignment and provide Upstream Capacity to Shipper required in accordance with this Agreement and to release Transporter from any obligations thereunder.

(c) Shipper shall indemnify and otherwise hold Transporter harmless from and against any and all claims and liabilities that may arise in connection with the Assignment or that Transporter may incur, acting reasonably, with respect to the Upstream Capacity to be assigned to Shipper, whether occurring prior or subsequent to the Effective Date, and including, without limitation, any payments made by Transporter to TCPL with respect to that Upstream Capacity.

5. Regulatory Approvals

Subject to the terms and conditions of this Agreement, each of Transporter and Shipper shall proceed with due diligence, having regard to the proposed in-service date of November 1, 2003, to apply for and obtain from all governmental and regulatory authorities having jurisdiction with respect to the Upstream Capacity such authorizations, permits, licenses and exemptions, and any necessary amendments or supplements thereto ("**Regulatory Approvals**"), which are necessary to assign the Upstream Capacity from Transporter to Shipper and to comply with obligations under this Agreement.

6. Shipper's Right to Release Capacity

To the extent Shipper releases an amount of its firm transportation service on the Inland Pacific Connector Project in accordance with the FTPA, Shipper shall have the right hereto to release a corresponding amount of Upstream Capacity to be assigned hereunder by notice to Transporter within the time period prescribed for release of the firm transportation service under the FTPA.

7. **Transporter's Conditions Precedent**

Notwithstanding the Parties' execution of this Agreement or the obligations of the Parties hereunder, Transporter's obligations to acquire and assign the Upstream Capacity are expressly made subject to:

(a) commitments from shippers for firm transportation service on the Inland Pacific Connector Project which Transporter determines in its sole discretion to make the project economical to proceed;

(b) Transporter's successful acquisition of Upstream Capacity for assignment on terms acceptable to Transporter in its sole discretion;

(c) Transporter's receipt and acceptance of all necessary regulatory and governmental approvals, licenses and permits from all interested regulatory and governmental bodies, including, without limitation, the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission, in form and substance satisfactory to Transporter, required to construct, own and operate the Inland Pacific Connector

Project and acquire and assign the Upstream Capacity on terms acceptable to Transporter in its sole discretion;

(d) approval of the board of directors of Transporter to the Inland Pacific Connector Project; and

(e) execution by Shipper of a binding FTSA for a quantity (less an allowance for fuel) equal to or greater than the Upstream Capacity to be assigned.

The foregoing conditions are for the exclusive benefit of Transporter and may be waived in whole or in part by Transporter in its sole discretion.

8. Assignment

(a) Transporter, without obtaining any approvals or consents from Shipper, may assign this Agreement or any rights arising under this Agreement to any affiliate of Transporter.

(b) Shipper has the right to assign its rights and obligations, or parts thereof, under this Agreement provided Shipper obtains the prior written consent of Transporter to the assignment, which consent shall not be unreasonably withheld. It shall not be unreasonable for Transporter to withhold consent if it determines, in its sole discretion, that the proposed assignee's creditworthiness is unsatisfactory.

(c) 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 Agreement.

(d) The restrictions on assignment contained in this Paragraph 8 shall not in any way prevent either Party from pledging or mortgaging its rights hereunder as security for its indebtedness, and Shipper hereby agrees, in connection with any collateral assignment made by Transporter for financing of the Inland Pacific Connector Project, to:

(i) execute and deliver, as soon as reasonably practical, a consent and agreement and opinion of counsel satisfactory to Transporter and in conformance with the terms of Transporter's financing commitments; and

(ii) provide any other information reasonably required by financial institutions providing financing for the Inland Pacific Connector Project.

9. Notices

Notices under this Agreement shall be in writing and shall be sent by personal delivery or facsimile to the address and facsimile number designated below:

Transporter: BC GAS INC.
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4
Attention: Business Leader, Project Development
Fax No.: (604) 443-6953

And a copy to: BC GAS INC.
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4
Attention: Legal Services
Fax No.: (604) 443-6789

Shipper: Name of Shipper: ______________________________

Address: ____________________________________

____

Contact Person: ______________________________

Fax No.: ______________________________________

Notice given hereunder shall be deemed to be received on the business day immediately following the day on which the facsimile was delivered (with transmission confirmed) or when delivered by hand or courier. Either party may change its address by written notice to that effect to the other party.

10. **Miscellaneous**

(a) This Agreement sets forth all understandings and agreements between the Parties respecting the subject matter hereof, and all prior agreements, understandings and representations, whether written or oral, respecting the subject matter hereof are merged into and superseded by this Agreement.

(b) This Agreement may only be amended by an instrument in writing executed by both Parties.

(c) This Agreement, and any actions, claims, demands or settlements hereunder shall be governed by and construed in accordance with the laws of British Columbia, without reference to any conflicts of law principles which might require the application of the laws of any other jurisdiction and the Parties irrevocably attorn to the exclusive jurisdiction of the courts therein.

(d) This Agreement and the obligations of the Parties are subject to all applicable laws, regulations, rules and orders of all governmental and regulatory bodies having jurisdiction.

(e) Any provision of this Agreement that is prohibited or unenforceable under the laws of British Columbia shall be ineffective and secured to the extent of the prohibition or unenforceability without invalidating or rendering unenforceable the remaining provisions hereof.

(f) A waiver by either Party of any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

(g) Shipper agrees to execute and deliver all such other and additional instruments and documents and to do such other acts as may be reasonably necessary to effectuate the terms and provisions of this Agreement.

(h) The terms, conditions and provisions of this Agreement shall be considered to have been prepared through the joint efforts of both Parties and shall not be construed against either Party as a result of the preparation or drafting thereof.

(i) This Agreement shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

(j) This Agreement may be executed in counterpart and by facsimile, and if executed in that manner, such counterparts and facsimile signatures shall constitute one and the same instrument as if the Parties had executed the same document. Each Party executing a counterpart of this Agreement shall deliver one executed copy of that counterpart to the other Party.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in counterparts by their proper officers duly authorized as of the first date hereinabove written.

BC GAS INC.	**[Shipper]**
By: ______________________	By: ______________________
Print Name: _________________	Print Name: _________________
Title: ______________________	Title: ______________________

SCHEDULE A

UPSTREAM CAPACITY

Daily Contract Quantity: _____________ 10^3m^3/day

Contact Term: ______ full years commencing on the in-service date (adjusted to November 1 contract year)

Appendix E

SPECIFIC ITEMS
SECTION 3450
research and development costs

.01 This Section deals with accounting for research and development activities of an enterprise. It does not apply to the following specialized activities [1]:

(a) Research and development activities conducted for others under contract.

(b) Activities that are unique to enterprises in the extractive industries, such as prospecting, acquisitions of mineral rights, exploration, drilling, mining and related mineral development. PROPERTY, PLANT AND EQUIPMENT, Section 3061, contains standards for measurement, presentation and disclosure of mining and oil and gas properties.

The Section does apply, however, to research and development activities in the extractive industries that are comparable in nature to those of other enterprises, such as the development or improvement of processes and techniques including those employed in exploration, drilling and extraction.

DEFINITIONS

.02 For purposes of this Section, research and development are defined as follows:

Research is planned investigation undertaken with the hope of gaining new scientific or technical knowledge and understanding. Such investigation may or may not be directed towards a specific practical aim or application.

Development is the translation of research findings or other knowledge into a plan or design for new or substantially improved materials, devices, products, processes, systems or services prior to the commencement of commercial production or use.

.03 The terms research and development are used to cover a wide range of activities. Classification of the related expenditures as, or between, research and development is often dependent on the type of business, its organization and the type of projects undertaken. However, the dividing line between these two types of activity will often be indistinct and a particular expenditure may have characteristics of more than one type.

.04 The following are examples of activities that typically would be included in research:

(a) laboratory research aimed at discovery of new knowledge;

(b) searching for applications of new research findings or other knowledge;

(c) conceptual formulation and design of possible product or process alternatives.

.05 The following are examples of activities that typically would be included in development:

(a) testing in search for, or evaluation of, product or process alternatives;

(b) design, construction and testing of pre-production prototypes and models;

(c) design of tools, jigs, moulds and dies involving new technology.

.06 The following are examples of activities that typically would be excluded from research and development:

(a) engineering follow-through in an early phase of commercial production;

(b) quality control during commercial production, including routine testing of products;

(c) trouble-shooting in connection with breakdowns during commercial production;

(d) routine or periodic alterations to existing products, production lines, manufacturing processes and other on-going operations, even though such alterations may represent improvements;

(e) adaptation of an existing capability to a particular requirement or customer's need as part of a continuing commercial activity;

(f) routine design of tools, jigs, moulds and dies;

(g) activity, including design and construction engineering, related to the construction, relocation, rearrangement or start-up of facilities or equipment other than facilities or equipment whose sole use is for a particular research and development project.

.07 Routine or promotional market research activities are not encompassed by the definitions of research and development. However, expenditure on market research activities undertaken to establish the existence and extent of a potential market, prior to the commencement of commercial production, is similar in nature to development expenditure and would be treated as a development cost.

ELEMENTS OF COSTS

.08 In determining the amount of the costs specifically attributable to research and development activities, the cost of materials and services consumed and the salaries, wages and other related costs of personnel engaged in such activities would be included. In addition, research and development costs would include a reasonable allocation of overhead, such an allocation usually being made on bases similar to those used in allocating overhead to inventories. Under present accounting practice, general and administrative costs that are not clearly related to a particular activity or function within the enterprise are treated as period costs and, accordingly, it is not usually appropriate to allocate such costs to research and development.

.09 Fixed assets may be acquired or constructed in order to provide facilities for research and/or development activities. The use of such fixed assets will usually extend over a number of accounting periods and, accordingly, they should be capitalized and written off over their useful life. The depreciation charge associated with such equipment and facilities used in research and development activities would be included as part of the costs incurred in such activities.

.10 There are instances where equipment and/or facilities, acquired for a particular project extending over a number of accounting periods, have no alternative uses once the project is completed. It has been suggested that the cost of such equipment and facilities should be included as part of the costs of the project at the time such costs are incurred rather than being apportioned over the life of the project. However, the Committee believes that apportionment over the life of the project is more appropriate since it reflects the cost of the equipment and facilities used in each accounting period.

.11 The cost of intangible assets, such as patents or licences, purchased from others for use in research and development activities is treated in a manner similar to the cost of equipment and facilities, as set out in paragraphs 3450.09 and 3450.10. Research and development costs would, therefore, include amortization of any purchased intangibles used in such activities that meet the criteria for amortization in GOODWILL AND OTHER INTANGIBLE ASSETS, Section 3062.

.12 The question has been raised as to whether interest and other costs of capital used to finance research and development activities should be included as part of the costs of such activities. The Committee believes that allocation of interest and other costs of capital to research and development costs is part of a broader question beyond the scope of this Section.

.13 ♦ *Research and development costs should include:*

(a) the cost of materials and services consumed in research and development activities;

(b) the salaries, wages and other related costs of personnel directly engaged in research and development activities;

(c) the depreciation of equipment and facilities to the extent that they are used for research and development activities;

(d) a reasonable allocation of overhead; and

(e) the amortization of intangibles to the extent that they are related to research and development activities. [AUG. 1978]

ACCOUNTING TREATMENT

.14 The allocation of the costs of research and development activities to accounting periods is determined by their relationship to the expected future benefits to be derived from those activities.

Research

.15 Expenditures incurred on research can be regarded as part of a continuing activity required to maintain an enterprise's business and its competitive position. In most cases, research activities will not produce identifiable benefits in future periods; the amount of future benefits and the period over which they will be received are usually uncertain. In general, one particular period rather than another will not be expected to benefit from an expenditure on research and, therefore, it is appropriate that such expenditures be charged to expense as they are incurred.

.16 ♦ *Research costs should be charged as an expense of the period in which* *they are incurred.* [AUG. 1978]

Development

.17 Development activities are normally undertaken with a reasonable expectation of commercial success and of future benefits arising from the work, either from increased revenue or from reduced costs. On these grounds, it may be argued that expenditures on development should be deferred to be matched against future revenue.

.18 The degree of certainty as to future benefits of particular development projects varies and, in many cases, the expected future benefits may be too uncertain to justify carrying the expenditure forward.

.19 ♦ *Development costs should be charged as an expense of the period in which they are incurred except in the circumstances set out in paragraph* 3450.21. [AUG. 1978]

.20 If it can be demonstrated that the product or process is technically and commercially feasible, the enterprise has shown an intention to sell or use the product or process and the enterprise has or could obtain adequate resources to complete the project, the future benefits could be regarded as being reasonably certain. Deferral of costs incurred for any project is considered to be appropriate when all the criteria set out in paragraph 3450.21 are satisfied.

.21 ♦ *Development costs should be deferred to future periods if all of the following criteria are satisfied:*

(a) *the product or process is clearly defined and the costs attributable thereto can be identified;*

(b) *the technical feasibility of the product or process has been established;*

(c) *the management of the enterprise has indicated its intention to produce and market, or use, the product or process;*

(d) *the future market for the product or process is clearly defined or, if it is to be used internally rather than sold, its usefulness to the enterprise has been established; and*

(e) *adequate resources exist, or are expected to be available, to complete the project.* [AUG. 1978]

.22 A development project may meet the criteria for deferment but the costs incurred may exceed the expected related revenues less estimated production, selling and administrative costs and additional development costs. In such circumstances, it would not be appropriate for the excess development costs to be carried forward to future periods. The excess would be written off as an expense of the period, with the amount expected to be recovered being deferred.

.23 ♦ *When a development project meets the criteria for deferment, as set out in paragraph* 3450.21, *the development costs should be deferred to the extent that their recovery can reasonably be regarded as assured.* [AUG. 1978]

.24 The deferral of development costs on a particular project would commence in the fiscal year in which the criteria for deferment have been met.

Development costs written off in prior years would not be reinstated because they were incurred at a time when the technical and commercial feasibility of the project was too uncertain to establish a relationship with future benefits and they were, therefore, proper charges in those past periods.

.25 ♦ *Development costs charged as expense in prior years should not be reinstated even though the uncertainties that had led to their being written off no longer apply.* [AUG. 1978]

.26 As with other deferred costs, deferred development costs will be amortized over future periods. The objective of the amortization should be to provide a systematic and rational matching of such costs with related benefits. To achieve this objective, the amortization would commence with commercial production or use and the basis would be established by reference to the benefits expected to arise from the sale or use of the product or process.

.27 Because of technological change and competition, it may be difficult to determine the future period over which the deferred development costs are to be amortized. However, while the uncertainties caused by technological and economic obsolescence may make it necessary to restrict any planned amortization period to a relatively short one, the selection of an appropriate time period would be a matter of judgment in each case. An appropriate basis for amortizing deferred development costs would frequently be determined by reference to the estimates of future sales or use applied in satisfying the criteria for deferment.

.28 ♦ *Amortization of development costs deferred to future periods should commence with commercial production or use of the product or process and should be charged as an expense on a systematic and rational basis by reference, where possible, to the sale or use of the product or process.* [AUG. 1978]

.29 At the end of each accounting period, it would be normal practice to review the unamortized balance of deferred development costs in the light of the current situation with respect to the projects to which such costs relate. The review of the unamortized balance for each project would be directed at determining whether criteria that had justified the deferral of the costs are still satisfied. If doubt exists, it would not be appropriate for the unamortized balance to be carried forward to future periods and it would be written off. If deferral continues to be appropriate, the amount of the unamortized balance of deferred costs with respect to each development project would be analyzed in relation to its recovery by expected future revenues less related costs. Any excess unamortized costs would be written off.

.30 The deferral of development costs and the determination of the basis of amortization are part of the normal process of making accounting estimates and judgment decisions, all or part of which may be proved by subsequent events to require change. Changes in accounting estimates are not regarded as errors and changes that become necessary as new information is available are properly reflected in the period when the estimates change and in applicable future periods (see ACCOUNTING CHANGES, Section 1506).

.31 If the periodic review indicates that deferral continues to be appropriate, the basis of amortization would also be evaluated to determine whether current events and circumstances indicate a change in the future benefits expected to be realized, which in turn would call for a modification of the amortization over remaining future periods.

.32 ♦ *The deferred development costs of a project should be reviewed at the end of each accounting period. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance should be written off as a charge to income of the period. When the criteria for deferment continue to be met but the amount of deferred development costs that can reasonably be regarded as assured of recovery through related future revenues, less relevant costs, is exceeded by the unamortized balance of such costs, the excess should be written off as a charge to income of the period.* [JAN. 1990]

.33 ♦ *When the periodic review of the unamortized deferred costs of a project indicates that the basis of amortization requires modification, the change should be applied prospectively* (see ACCOUNTING CHANGES, Section 1506). [AUG. 1978]

STATEMENT PRESENTATION AND DISCLOSURE

.34 ♦ *The financial statements should disclose the amounts of:*

(a) *unamortized deferred development costs;*

(b) *development costs deferred during the period;*

(c) *research and development costs charged to expense for the period; and*

(d) *amortization of deferred development costs charged to expense for the period.* [AUG. 1978 *]

.35 ♦ *The description of the basis of valuation of deferred development costs should disclose the fact that amortization has been deducted in arriving at the carrying value and the basis on which that amortization has been calculated* (see DISCLOSURE OF ACCOUNTING POLICIES, Section 1505). A description of the general nature of the projects on which development costs are deferred may provide useful information. [AUG. 1978 *]

Appendix F

GENERAL ACCOUNTING
SECTION 1000
financial statement concepts

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PURPOSE AND SCOPE

.01 The purpose of this Section is to describe the concepts underlying the development and use of accounting principles in general purpose financial statements (hereafter referred to as financial statements). Such financial statements are designed to meet the common information needs of external users of financial information about an entity. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES, Section 1100, establishes standards for financial reporting in accordance with generally accepted accounting principles. It describes what constitutes Canadian generally accepted accounting principles and their sources.

.02 The Committee expects this Section to be used by preparers of financial statements and accounting practitioners in exercising their professional judgment as to the application of generally accepted accounting principles and in establishing accounting policies in areas in which accounting principles are developing.

.03 This Section does not establish standards for particular measurement or disclosure issues. Nothing in the Section overrides any specific Recommendation in another Section of the Handbook or any other accounting principle considered to be generally accepted. Any inconsistency between this Section and another Section will be reviewed by the Committee when that other Section is re-examined.

Financial statements

.04 Financial statements of profit oriented enterprises normally include a balance sheet, income statement, statement of retained earnings and cash flow statement. Financial statements of not-for-profit organizations normally include a statement of financial position, a statement of operations, a statement of changes in net assets and a statement of cash flows. Notes to financial statements and supporting schedules to which the financial statements are cross-referenced are an integral part of such statements.

.05 The content of financial statements is usually limited to financial information about transactions and events. Financial statements are based on representations of past, rather than future, transactions and events although they often require estimates to be made in anticipation of future transactions and events and include measurements that may, by their nature, be approximations.

.06 Financial statements form part of the process of financial reporting that includes also, for example, information in annual reports outside the financial statements and in prospectuses and in funding proposals. While many financial statement concepts also apply to such information, this Section deals specifically only with financial statements.

OBJECTIVE OF FINANCIAL STATEMENTS

.07 In the Canadian economic environment, the production of goods and the provision of services are, to a significant extent, carried out by investor-owned business enterprises in the private sector and to a lesser extent by government-owned business enterprises. Debt and equity markets and financial institutions act as exchange mechanisms for investment resources used by these enterprises.

.08 The provision of services and, in some cases, the production of goods, are also carried out by not-for-profit organizations in both the private and public sectors. Not-for-profit organizations are often not subject to the same exchange mechanisms as are profit-oriented enterprises. However, they are often restricted by spending mandates imposed by their members and contributors. Contributors include individuals, corporations, organizations and other donors such as governments and other public sector bodies that grant funds for specified and non-specified purposes.

.09 Ownership of profit-oriented enterprises is often segregated from management, creating a need for external communication of economic information about the entity to investors. For the purposes of this Section, investors include present and potential debt and equity investors and their advisers. Creditors and others who do not have internal access to entity information also need external reports to obtain the information they require. In the case of financial institutions, investors, creditors and others include depositors and policyholders.

.10 Members of and contributors to not-for-profit organizations are also often segregated from management creating a similar need for external communication of economic information about the entity to members and contributors. A not-for-profit organization's creditors and others who do not have internal access to entity information also need external reports to obtain the information they require.

.11 It is not practicable to expect financial statements to satisfy the many and varied information needs of all external users of information about an entity. Consequently, the objective of financial statements for profit-oriented enterprises focuses primarily on information needs of investors and creditors and, for not-for-profit organizations, focuses primarily on information needs of members, contributors and creditors. Financial statements prepared to satisfy these needs are often used by others who need external reporting of information about an entity.

.12 Investors and creditors of profit-oriented enterprises are interested, for the purpose of making resource allocation decisions, in predicting the ability of the entity to earn income and generate cash flows in the future to meet its obligations and to generate a return on investment.

.13 Members, contributors and creditors of not-for-profit organizations are interested, for the purpose of making resource allocation decisions, in the entity's cost of service and how that cost was funded and in predicting the ability of the entity to meet its obligations and achieve its service delivery objectives.

.14 Investors, members and contributors also require information about how the management of an entity has discharged its stewardship responsibility to those that have provided resources to the entity. Information regarding discharge of the stewardship responsibilities is especially important in the not-for-profit sector where resources are often contributed for specific purposes and management is accountable for the appropriate utilization of such resources.

Objective

.15 The objective of financial statements is to communicate information that is useful to investors, members, contributors, creditors and other users ("users") in making their resource allocation decisions and/or assessing management stewardship. Consequently, financial statements provide information about:

(a) an entity's economic resources, obligations and equity / net assets;

(b) changes in an entity's economic resources, obligations and equity / net assets; and

(c) the economic performance of the entity.

BENEFIT VERSUS COST CONSTRAINT

.16 The benefits expected to arise from providing information in financial statements should exceed the cost of doing so. In developing accounting standards, the Board weighs the anticipated costs and benefits of its proposals in general terms to assess whether they are justified on cost / benefit grounds. The benefits and costs of applying accounting standards may differ between entities depending in part on the nature, number and information needs of the users of their financial statements. Therefore, in developing an accounting standard, the Board considers whether the requirements of that standard should apply to all entities or whether different requirements should apply to different types of entities for which the cost / benefit trade-off differs significantly. The cost / benefit trade-off is also a consideration for individual entities in the preparation of financial statements in accordance with applicable standards, for example, in considering disclosure of information beyond that required by the standards. The Board recognizes that the evaluation of the nature and amount of benefits and costs is substantially a judgmental process.

MATERIALITY

.17 Users are interested in information that may affect their decision making. Materiality is the term used to describe the significance of financial statement information to decision makers. An item of information, or an aggregate of items, is material if it is probable that its omission or misstatement would influence or change a decision. Materiality is a matter of professional judgment in the particular circumstances.

QUALITATIVE CHARACTERISTICS

.18 Qualitative characteristics define and describe the attributes of information provided in financial statements that make that information useful to users. The four principal qualitative characteristics are understandability, relevance, reliability and comparability.

Understandability

.19 For the information provided in financial statements to be useful, it must be capable of being understood by users. Users are assumed to have a reasonable understanding of business and economic activities and accounting, together with a willingness to study the information with reasonable diligence.

Relevance

.20 For the information provided in financial statements to be useful, it must be relevant to the decisions made by users. Information is relevant by its nature when it can influence the decisions of users by helping them evaluate the financial impact of past, present or future transactions and events or confirm, or correct, previous evaluations. Relevance is achieved through information that has predictive value or feedback value and by its timeliness.

(a) **Predictive value and feedback value**

Information that helps users to predict an entity's future income and cash flows has predictive value. Although information provided in financial statements will not normally be a prediction in itself, it may be useful in making predictions. The predictive value of the income statement, for example, is enhanced if abnormal items are separately disclosed. Information that confirms or corrects previous predictions has feedback value. Information often has both predictive value and feedback value.

(b) **Timeliness**

For information to be useful for decision making, it must be received by the decision maker before it loses its capacity to influence decisions. The usefulness of information for decision making declines as time elapses.

Reliability

.21 For the information provided in financial statements to be useful, it must be reliable. Information is reliable when it is in agreement with the actual underlying transactions and events, the agreement is capable of independent verification and the information is reasonably free from error and bias. Reliability is achieved through representational faithfulness, verifiability and neutrality. Neutrality is affected by the use of conservatism in making judgments under conditions of uncertainty.

(a) **Representational faithfulness**

Representational faithfulness is achieved when transactions and events affecting the entity are presented in financial statements in a manner that is in agreement with the actual underlying transactions and events. Thus, transactions and events are accounted for and presented in a manner that conveys their substance rather than necessarily their legal or other form.

The substance of transactions and events may not always be consistent with that apparent from their legal or other form. To determine the substance of a transaction or event, it may be necessary to consider a group of related transactions and events as a whole. The determination of the substance of a transaction or event will be a matter of professional judgment in the circumstances.

(b) **Verifiability**

The financial statement representation of a transaction or event is verifiable if knowledgeable and independent observers would concur that it is in agreement with the actual underlying transaction or event with a reasonable degree of precision. Verifiability focuses on the correct application of a basis of measurement rather than its appropriateness.

(c) **Neutrality**

Information is neutral when it is free from bias that would lead users toward making decisions that are influenced by the way the information is measured or presented. Bias in measurement occurs when a measure tends to consistently overstate or understate the items being measured. In the selection of accounting principles, bias may occur when the selection is made with the interests of particular users or with particular economic or political objectives in mind.

Financial statements that do not include everything necessary for faithful representation of transactions and events affecting the entity would be incomplete and, therefore, potentially biased.

(d) **Conservatism**

Use of conservatism in making judgments under conditions of uncertainty affects the neutrality of financial statements in an acceptable manner. When uncertainty exists, estimates of a conservative nature attempt to ensure that assets, revenues and gains are not overstated and, conversely, that liabilities, expenses and losses are not understated. However, conservatism does not encompass the deliberate understatement of assets, revenues and gains or the deliberate overstatement of liabilities, expenses and losses.

Comparability

.22 Comparability is a characteristic of the relationship between two pieces of information rather than of a particular piece of information by itself. It enables users to identify similarities in and differences between the information provided by two sets of financial statements. Comparability is important when comparing the financial statements of two different entities and when comparing the financial statements of the same entity over two periods or at two different points in time.

.23 Comparability in the financial statements of an entity is enhanced when the same accounting policies are used consistently from period to period. Consistency helps prevent misconceptions that might result from the application of different accounting policies in different periods. When a change in accounting policy is deemed to be appropriate, disclosure of the effects of the change may be necessary to maintain comparability.

Qualitative characteristics trade-off

.24 In practice, a trade-off between qualitative characteristics is often necessary, particularly between relevance and reliability. For example, there is often a trade-off between the timeliness of producing financial statements and the reliability of the information reported in the statements. Generally, the aim is to achieve an appropriate balance among the characteristics in order to meet the objective of financial statements. The relative importance of the characteristics in different cases is a matter of professional judgment.

ELEMENTS OF FINANCIAL STATEMENTS

.25 Elements of financial statements are the basic categories of items portrayed therein in order to meet the objective of financial statements. There are two types of elements: those that describe the economic resources, obligations and equity / net assets of an entity at a point in time, and those that describe changes in economic resources, obligations and equity / net assets over a period of time. Notes to financial statements, which are useful for the purpose of clarification or further explanation of the items in financial statements, while an integral part of financial statements, are not considered to be an element.

.26 The elements defined herein are the most common categories of items portrayed in financial statements. The existence of other items is not precluded. In practice, a balance sheet may include, as a category of assets or liabilities, items that result from a delay in recognition of revenue, expenses, gains and losses. Criteria for the recognition of items in financial statements are discussed in paragraph 1000.44.

.27 In the case of profit-oriented enterprises, comprehensive income is the residual amount after expenses and losses are deducted from revenues and gains. Comprehensive income includes all transactions and events increasing or decreasing the equity of the profit-oriented enterprise except those that result from equity contributions and distributions.

.28 In the case of not-for-profit organizations, the excess or deficiency of revenues and gains over expenses and losses is an important indicator to users of the extent to which a not-for-profit organization has been able to obtain resources to cover the cost of its services.

Assets

.29 Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

.30 Assets have three essential characteristics:

(a) they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

(b) the entity can control access to the benefit; and

(c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

.31 It is not essential for control of access to the benefit to be legally enforceable for a resource to be an asset, provided the entity can control its use by other means.

Liabilities

.32 Liabilities are obligations of an entity arising from past transactions or events, the settlement of which may result in the transfer or use of assets, provision of services or other yielding of economic benefits in the future.

.33 Liabilities have three essential characteristics:

(a) they embody a duty or responsibility to others that entails settlement by future transfer or use of assets, provision of services or other yielding of economic benefits, at a specified or determinable date, on occurrence of a specified event, or on demand;

(b) the duty or responsibility obligates the entity leaving it little or no discretion to avoid it; and

(c) the transaction or event obligating the entity has already occurred.

.34 Liabilities do not have to be legally enforceable provided that they otherwise meet the definition of liabilities; they can be based on equitable or constructive obligations. An equitable obligation is a duty based on ethical or moral considerations. A constructive obligation is one that can be inferred from the facts in a particular situation as opposed to a contractually based obligation.

Equity / Net assets

.35 Equity is the ownership interest in the assets of a profit-oriented enterprise after deducting its liabilities. While equity of a profit-oriented enterprise in total is a residual, it includes specific categories of items, for example, types of share capital, contributed surplus and retained earnings.

.36 In the case of a not-for-profit organization, net assets, sometimes referred to as equity or fund balances, is the residual interest in its assets after deducting its liabilities. Net assets may include specific categories of items that may be either restricted or unrestricted as to their use.

Revenues

.37 Revenues are increases in economic resources, either by way of inflows or enhancements of assets or reductions of liabilities, resulting from the ordinary activities of an entity. Revenues of entities normally arise from the sale of goods, the rendering of services or the use by others of entity resources yielding rent, interest, royalties or dividends. In addition, many not-for-profit organizations receive a significant proportion of their revenues from donations, government grants and other contributions.

Expenses

.38 Expenses are decreases in economic resources, either by way of outflows or reductions of assets or incurrences of liabilities, resulting from an entity's ordinary revenue generating or service delivery activities.

Gains

.39 Gains are increases in equity / net assets from peripheral or incidental transactions and events affecting an entity and from all other transactions, events and circumstances affecting the entity except those that result from revenues or equity / net assets contributions.

Losses

.40 Losses are decreases in equity / net assets from peripheral or incidental transactions and events affecting an entity and from all other transactions, events and circumstances affecting the entity except those that result from expenses or distributions of equity / net assets.

RECOGNITION CRITERIA

.41 Recognition is the process of including an item in the financial statements of an entity. Recognition consists of the addition of the amount involved into statement totals together with a narrative description of the item (e.g., "inventory", "sales", or "donations") in a statement. Similar items may be grouped together in the financial statements for the purpose of presentation.

.42 Recognition means inclusion of an item within one or more individual statements and does not mean disclosure in the notes to the financial statements. Notes either provide further details about items recognized in the financial statements, or provide information about items that do not meet the criteria for recognition and thus are not recognized in the financial statements.

.43 The recognition criteria below provide general guidance on when an item is recognized in the financial statements. Whether any particular item is recognized or not will require the application of professional judgment in considering whether the specific circumstances meet the recognition criteria.

.44 The recognition criteria are as follows:

(a) the item has an appropriate basis of measurement and a reasonable estimate can be made of the amount involved; and

(b) for items involving obtaining or giving up future economic benefits, it is probable that such benefits will be obtained or given up.

.45 It is possible that an item will meet the definition of an element but still not be recognized in the financial statements because it is not probable that future economic benefits will be obtained or given up or because a reasonable estimate cannot be made of the amount involved. It may be appropriate to provide information about items that do not meet the recognition criteria in notes to the financial statements.

.46 Items recognized in financial statements are accounted for in accordance with the accrual basis of accounting. The accrual basis of accounting recognizes the effect of transactions and events in the period in which the transactions and events occur, regardless of whether there has been a receipt or payment of cash or its equivalent. Accrual accounting encompasses deferrals that occur when a cash receipt or payment occurs prior to the criteria for recognition of revenue or expense being satisfied.

.47 Revenues are generally recognized when performance is achieved and reasonable assurance regarding measurement and collectibility of the consideration exists.

.48 Unrestricted contributions to not-for-profit organizations do not normally arise from the sale of goods or the rendering of services and consequently performance achievement is generally not relevant to the recognition of unrestricted contributions; such revenues, since they are not linked with specific expenses, are generally recognized when received or receivable. Other contributions are recognized based on the nature of the related restriction.

.49 Gains are generally recognized when realized.

.50 Expenses and losses are generally recognized when an expenditure or previously recognized asset does not have future economic benefit. Expenses that are not linked with specific revenues are related to a period on the basis of transactions or events occurring in that period or by allocation. The cost of assets that benefit more than one period is normally allocated over the periods benefited.

.51 Expenses that are linked to revenue generating activities in a cause and effect relationship are normally matched with the revenue in the accounting period in which the revenue is recognized.

.52 Expenses incurred by not-for-profit organizations for service delivery activities, as opposed to revenue generating activities, would normally be recognized when the service is delivered.

MEASUREMENT

.53 Measurement is the process of determining the amount at which an item is recognized in the financial statements. There are a number of bases on which an amount can be measured. However, financial statements are prepared primarily using the historical cost basis of measurement whereby transactions and events are recognized in financial statements at the amount of cash or cash equivalents paid or received or the fair value ascribed to them when they took place.

.54 Other bases of measurement are also used but only in limited circumstances. They include:

(a) Replacement cost — the amount that would be needed currently to acquire an equivalent asset. This may be used, for example, when inventories are valued at the lower of historical cost and replacement cost.

(b) Realizable value — the amount that would be received by selling an asset. This may be used, for example, to value temporary and portfolio investments. Market value may be used to estimate realizable value when a market for an asset exists.

(c) Present value — the discounted amount of future cash flows expected to be received from an asset or required to settle a liability. This is used, for example, to estimate the cost of pension benefits.

.55 Financial statements are prepared with capital maintenance measured in financial terms and with no adjustment being made for the effect on capital of a change in the general purchasing power of the currency during the period.

.56 The concept of capital maintenance used by profit-oriented enterprises in preparing financial statements affects measurement because income in an economic sense exists only after the capital of an enterprise has been maintained. Thus, income is the increase or decrease in the amount of capital at the end of the period over the amount at the beginning of the period, excluding the effects of capital contributions and distributions.

.57 The concept of service potential [1] maintenance which, for not-for-profit organizations, would generally be more appropriate than the concept of financial capital maintenance, cannot entirely be measured in financial terms.

.58 Financial statements are prepared on the assumption that the entity is a going concern, meaning it will continue in operation for the foreseeable future and will be able to realize assets and discharge liabilities in the normal course of operations. Different bases of measurement may be appropriate when the entity is not expected to continue in operation for the foreseeable future.

(paragraphs 1000.59-.61 deleted)

Appendix G

SPECIFIC ITEMS
SECTION 3061
property, plant and equipment

TABLE OF CONTENTS	**Paragraph**

PURPOSE AND SCOPE

.01 This Section establishes standards for the recognition, measurement, presentation and disclosure of property, plant and equipment (tangible capital assets) by profit-oriented enterprises. This Section applies to property, plant and equipment recognized under LEASES, Section 3065. Not-for-profit organizations would account for property, plant and equipment in accordance with CAPITAL ASSETS HELD BY NOT-FOR-PROFIT ORGANIZATIONS, Section 4430.

.02 This Section does not deal with goodwill or other intangible assets (see GOODWILL AND OTHER INTANGIBLE ASSETS, Section 3062), with the impairment of property, plant and equipment (see IMPAIRMENT OF LONG-LIVED ASSETS, Section 3063) or with the disposal of property, plant and equipment (see DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS, Section 3475). This Section also does not deal with special circumstances when it may be appropriate to undertake a comprehensive revaluation of all the assets and liabilities of an enterprise (see COMPREHENSIVE REVALUATION OF ASSETS AND LIABILITIES, Section 1625).

DEFINITIONS

.03 The definitions that follow have been adopted for the purposes of this Section.

.04 **Property, plant and equipment** are identifiable tangible assets that meet all of the following criteria:

(a) are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other property, plant and equipment;

(b) have been acquired, constructed or developed with the intention of being used on a continuing basis; and

(c) are not intended for sale in the ordinary course of business.

Property, plant and equipment and intangible assets other than goodwill (see GOODWILL AND OTHER INTANGIBLE ASSETS, Section 3062) are referred to collectively as "capital assets".

.05 **Cost** is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use. Cost includes any asset retirement cost accounted for in accordance with ASSET RETIREMENT OBLIGATIONS, Section 3110.

.06 **Mining properties** are items of property, plant and equipment represented by the capitalized costs of acquired mineral rights and the costs associated with exploration for and development of mineral reserves.

.07 **Net carrying amount** of an item of property, plant and equipment is cost less both accumulated amortization and the amount of any write-downs.

.08 **Net recoverable amount** of an item of property, plant and equipment is its estimated future net cash flow from use together with its residual value.

.09 **Oil and gas properties** are items of property, plant and equipment represented by the capitalized costs of acquired oil and gas rights and the costs associated with exploration for and development of oil, gas and related reserves.

.10 **Rate-regulated property, plant and equipment** are items of property, plant and equipment held for use in operations meeting all of the following criteria:

(a) The rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products.

(b) The regulated rates are designed to recover the cost of providing the services or products.

(c) It is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for any capitalized costs.

.11 **Rental real estate** is real estate held primarily to generate income through rental to others, i.e., not held for sale in the ordinary course of business. It includes rental property under development and developed property that is intended to be held for rental. In addition, it includes land designated for development as rental property.

.12 **Residual value** is the estimated net realizable value of an item of property, plant and equipment at the end of its useful life to an enterprise.

.13 **Salvage value** is the estimated net realizable value of an item of property, plant and equipment at the end of its life. Salvage value is normally negligible.

.14 **Service potential** is used to describe the output or service capacity of an item of property, plant and equipment and is normally determined by reference to attributes such as physical output capacity, associated operating costs, useful life and quality of output.

.15 **Useful life** is the period over which an asset, singly or in combination with other assets, is expected to contribute directly or indirectly to the future cash flows of an enterprise.

MEASUREMENT

Cost

.16 ♦ *Property, plant and equipment should be recorded at cost.* [DEC. 1990 *]

.17 The cost of an item of property, plant and equipment includes the purchase price and other acquisition costs such as option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges. In addition, if the cost of the asset acquired other than through a business combination is different from its tax basis on acquisition, the asset's cost would be adjusted to reflect the related future income tax consequences (see INCOME TAXES, Section 3465). It may be appropriate to group together individually insignificant items of property, plant and equipment.

.18 The cost of each item of property, plant and equipment acquired as part of a basket purchase (i.e., when a group of assets is acquired for a single amount), is determined by allocating the price paid for the basket to each item on the basis of its relative fair value at the time of acquisition. (For guidance on the determination of fair value see BUSINESS COMBINATIONS, Section 1581.)

.19 When, at the time of acquisition, a portion of the acquired item of property, plant and equipment meets the criteria in DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS, Section 3475, to be classified as held for sale at the acquisition date, that portion of the item is measured at fair value less cost to sell. The remainder of the acquired item is measured at the cost of acquisition of the entire item less the amount assigned to the portion to be sold. For example, if a portion of land acquired is to be resold, the cost of the land to be retained would be the total cost of the purchase minus the fair value less cost to sell of the portion of land held for sale. When, at the time of acquisition, a portion of the acquired item of property, plant and equipment is not intended for use because it will be abandoned, its cost and any costs of disposal, net of any estimated proceeds, are attributed to that portion of the acquired asset which is intended for use. For example, the cost of acquired land that includes a building which will be demolished, comprises the cost of the acquired property and the cost of demolishing the building.

Acquisition, construction or development over time

.20 The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

.21 For a mining property, the cost of the asset includes exploration costs if the enterprise considers that such costs have the characteristics of property, plant and equipment. An enterprise applies the method of accounting for exploration costs that it considers to be appropriate to its operations and applies the method consistently to all its properties.

.22 For an oil and gas property, the cost of the asset comprises acquisition costs, development costs and certain exploration costs depending on whether the enterprise accounts for its oil and gas properties using the full cost method or the successful efforts method. An enterprise applies the method of accounting for acquisition, exploration and development costs that it considers to be appropriate to its operations and applies the method consistently to all its properties.

.23 The cost of an item of property, plant and equipment that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity such as interest costs when the enterprise's accounting policy is to capitalize interest costs. For an item of rate-regulated property, plant and equipment, the cost includes the directly attributable allowance for funds used during construction allowed by the regulator.

.24 Capitalization of carrying costs ceases when an item of property, plant and equipment is substantially complete and ready for productive use. Determining when an asset, or a portion thereof, is substantially complete and ready for productive use requires consideration of the circumstances and the industry in which it is to be operated. Normally it would be predetermined by management with reference to such factors as productive capacity, occupancy level, or the passage of time.

.25 Net revenue or expense derived from an item of property, plant and equipment prior to substantial completion and readiness for use is included in the cost.

Betterment

.26 The cost incurred to enhance the service potential of an item of property, plant and equipment is a betterment. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The cost incurred in the maintenance of the service potential of an item of property, plant and equipment is a repair, not a betterment. If a cost has the attributes of both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset.

.27 A redevelopment project that adds significant economic value to rental real estate is treated as a betterment. When a building is removed for the purpose of redevelopment of rental real estate, the net carrying amount of the building is included in the cost of the redeveloped property, as long as the net amount considered recoverable from the redevelopment project exceeds its cost.

Amortization

.28 ♦ *Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise. The amount of amortization that should be charged to income is the greater of:*

(a) *the cost less salvage value over the life of the asset; and*

(b) *the cost less residual value over the useful life of the asset.* [DEC. 1990 *]

.29 Property, plant and equipment is acquired to earn income or supply a service over its useful life. An item of property, plant and equipment, other than land that normally has an unlimited life, has a limited life. Its useful life is normally the shortest of its physical, technological, commercial and legal life. Amortization is the charge to income that recognizes that life is finite and that the cost less salvage value or residual value of an item of property, plant and equipment is allocated to the periods of service provided by the asset. Amortization may also be termed depreciation or depletion.

.30 The cost of an item of property, plant and equipment made up of significant separable component parts is allocated to the component parts when practicable and when estimates can be made of the lives of the separate components. For example, initial leasing costs may be identifiable as a separable component of the cost of rental real estate and engines may be a separable component of an aircraft.

.31 Different methods of amortizing an item of property, plant and equipment result in different patterns of charges to income. The objective is to provide a rational and systematic basis for allocating the amortizable amount of an item of property, plant and equipment over its estimated life and useful life. A straight-line method reflects a constant charge for the service as a function of time. A variable charge method reflects service as a function of usage. Other methods may be appropriate in certain situations. For example, an increasing charge method may be used when an enterprise can price its goods or services so as to obtain a constant rate of return on the investment in the asset; a decreasing charge method may be appropriate when the operating efficiency of the asset declines over time.

.32 Factors to be considered in estimating the life and useful life of an item of property, plant and equipment include expected future usage, effects of technological or commercial obsolescence, expected wear and tear from use or the passage of time, the maintenance program, results of studies made regarding the industry, studies of similar items retired, and the condition of existing comparable items. As the estimate of the life of an item of property, plant and equipment is extended into the future, it becomes increasingly difficult to identify a reasonable basis for estimating the life.

Review of amortization

.33 ♦ *The amortization method and estimates of the life and useful life of an* *item of property, plant and equipment should be reviewed on a regular basis.* [DEC. 1990 *]

.34 Significant events that may indicate a need to revise the amortization method or estimates of the life and useful life of an item of property, plant and equipment include:

(a) a change in the extent the asset is used;

(b) a change in the manner in which the asset is used;

(c) removal of the asset from service for an extended period of time;

(d) physical damage;

(e) significant technological developments;

(f) a change in the law, environment, or consumer styles and tastes affecting the period of time over which the asset can be used.

Asset retirement obligations

.35 Obligations associated with the retirement of property, plant and equipment are accounted for in accordance with ASSET RETIREMENT OBLIGATIONS, Section 3110.

(paragraphs 3061.36-.37 deleted)

PRESENTATION AND DISCLOSURE

.38 ♦ *For each major category of property, plant and equipment there should be disclosure of:*

(a) cost;

(b) accumulated amortization, including the amount of any write-downs; and

(c) the amortization method used, including the amortization period or rate. [DEC. 1990 *]

.39 ♦ *The net carrying amount of an item of property, plant and equipment not being amortized, because it is under construction or development, or has been removed from service for an extended period of time, should be disclosed.* [DEC. 1990 *]

.40 ♦ *The amount of amortization of an item of property, plant and equipment charged to income for the period should be disclosed* (see INCOME STATEMENT, Section 1520). [DEC. 1990 *]

.41 The presentation and requirements of IMPAIRMENT OF LONG-LIVED ASSETS, Section 3063, and DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS, Section 3475, apply to property, plant and equipment.

.42 Major categories of property, plant and equipment are determined by reference to type (for example, land, buildings, machinery, leasehold improvements), operating segment and/or nature of operations (for example, manufacturing, processing, distribution, rental real estate).

(paragraph 3061.43 deleted)

PROPERTY, PLANT AND EQUIPMENT RECORDED AT APPRAISED VALUES

.44 ♦ *When an enterprise has an item of property, plant and equipment that was recorded at an appraised value prior to the effective date of this Section, the following additional requirements apply:*

(a) *the basis of the valuation and the date of the appraisal should be disclosed;*

(b) *charges against income should be based on the appraised value; and*

(c) *appraisal increase credits should be shown as a separate item in accumulated other comprehensive income. The appraisal increase should be transferred to retained earnings in amounts equal to the realization of appreciation through sale or the amortization provision. The basis of any transfer to retained earnings should be disclosed.* [OCT. 2006]

TRANSITIONAL PROVISIONS

.45 This Section applies to all fiscal periods beginning on or after December 1, 1990. However, earlier adoption is encouraged. The Section may be applied either prospectively or retroactively.

.46 When this Section is applied prospectively, it is applied to all property, plant and equipment existing on the date of adoption of the Section.

.47 When this Section is applied retroactively, any resulting adjustments are treated as a retroactive application of a change in an accounting policy (see ACCOUNTING CHANGES, Section 1506).

.48 The reference to accumulated other comprehensive income in paragraph 3061.44(c) applies when an entity adopts COMPREHENSIVE INCOME, Section 1530.

Appendix H

SPECIFIC ITEMS
SECTION 3063
impairment of long-lived assets

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PURPOSE AND SCOPE

.01 This Section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets by profit-oriented enterprises. This Section applies to long-lived assets held for use. It does not deal with long-lived assets to be disposed of (see DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS, Section 3475). Not-for-profit organizations would account for the impairment of long-lived assets in accordance with CAPITAL ASSETS HELD BY NOT-FOR-PROFIT ORGANIZATIONS, Section 4430.

.02 This Section applies to non-monetary long-lived assets, including property, plant and equipment, intangible assets with finite useful lives, deferred pre-operating costs and long-term prepaid assets. It does not apply to:

(a) goodwill and intangible assets with indefinite useful lives (see GOODWILL AND OTHER INTANGIBLE ASSETS, Section 3062);

(b) impaired loans (see IMPAIRED LOANS, Section 3025);

(c) investments, including equity method accounted investments (see INVESTMENTS, Section 3051);

(d) deferred charges, other than deferred pre-operating costs;

(e) deferred development costs (see RESEARCH AND DEVELOPMENT COSTS, Section 3450);

(f) accrued benefit assets (see EMPLOYEE FUTURE BENEFITS, Section

3461);

(g) future income tax assets (see INCOME TAXES, Section 3465);

(h) financial assets, financial liabilities and contracts to buy or sell non-financial items that are within the scope of FINANCIAL INSTRUMENTS — RECOGNITION AND MEASUREMENT, Section 3855;

(i) deferred policy acquisition costs (see ACCOUNTING GUIDELINE AcG-3, Financial Reporting by Property and Casualty Insurance Companies);

(j) oil and gas assets accounted for using the full cost method (see ACCOUNTING GUIDELINE AcG-16, Oil and Gas Accounting — Full Cost);

(k) unproved oil and gas properties accounted for using the successful efforts method; or

(l) servicing assets (see ACCOUNTING GUIDELINE AcG-12, Transfers of Receivables).

DEFINITIONS

.03 The following terms are used in this Section with the meanings specified:

(a) An **asset group** is the lowest level (smallest combination) of assets and liabilities for which identifiable cash flows are largely independent of the cash flows of other assets or groups of assets and liabilities.

(b) **Fair value** is the amount of the consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

(c) **Impairment** is the condition that exists when the carrying amount of a long-lived asset exceeds its fair value.

(d) A **long-lived asset** is an asset that does not meet the definition of a current asset (see CURRENT ASSETS AND CURRENT LIABILITIES, Section 1510). For purposes of this Section, the term "long-lived asset" includes an asset group.

RECOGNITION AND MEASUREMENT

.04 ♦ *An impairment loss should be recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value.* [APRIL 2003]

.05 The carrying amount of a long-lived asset is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. This assessment is based on the carrying amount of the asset at the date it is tested for recoverability, whether it is in use or under development.

.06 ♦ *An impairment loss should be measured as the amount by which the carrying amount of a long-lived asset exceeds its fair value. If an impairment loss is recognized, the adjusted carrying amount becomes the new cost basis. For a depreciable long-lived asset, the new cost basis should be amortized in accordance with PROPERTY, PLANT AND EQUIPMENT, Section 3061. An impairment loss should not be reversed if the fair value subsequently increases.* [APRIL 2003]

.07 Guidance on determining fair value for use in measuring the amount of an impairment loss is provided in the Appendix. Illustrative Examples of the application of this Section are also provided.

.08 When an entity has capitalized asset retirement costs (see ASSET RETIREMENT OBLIGATIONS, Section 3110), these costs are included in the carrying amount of the asset being tested for impairment. Estimated future cash flows related to the liability for an asset retirement obligation that has been recognized in the financial statements are excluded from the cash flows used to test the asset for recoverability and to measure the asset's fair value. However, when an asset group is the only source of cash flow to pay the asset retirement obligation, the liability is included in the asset group in accordance with paragraph 3063.12 and the estimated future cash flows related to the liability are included in the cash flows of the asset group. When the fair value of the asset is based on a quoted market price and that price considers the costs that will be incurred in retiring that asset, the quoted market price is increased by the fair value of the asset retirement obligation for purposes of measuring impairment.

When to test for recoverability

.09 ♦ *A long-lived asset should be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable.* [APRIL 2003]

.10 Examples of such events or changes in circumstances related to a long-lived asset include, but are not restricted to:

(a) a significant decrease in its market price;

(b) a significant adverse change in the extent or manner in which it is being used or in its physical condition;

(c) a significant adverse change in legal factors or in the business climate that could affect its value, including an adverse action or assessment by a regulator;

(d) an accumulation of costs significantly in excess of the amount originally expected for its acquisition or construction;

(e) a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with its use; or

(f) a current expectation that, more likely than not, it will be sold or otherwise disposed of significantly before the end of its previously estimated useful life ("more likely than not" means a level of likelihood that is more than 50 percent).

There may also be other indications that the carrying amount of an asset is not recoverable.

.11 When a long-lived asset is tested for recoverability, it also may be necessary to review amortization estimates and methods. Any revision to the remaining useful life resulting from that review is also considered in developing estimates of future cash flows used to test for recoverability. However, any change in the amortization of the asset that results from the review is made only after recording any impairment loss in accordance with this Section.

Grouping assets

.12 ♦ *For purposes of recognition and measurement of an impairment loss, a long-lived asset should be grouped with other assets and liabilities to form an asset group, at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities.* [APRIL 2003]

.13 A long-lived asset may not have identifiable cash flows that are largely independent of the cash flows of other assets and liabilities and of other asset groups (for example, a corporate headquarters facility, or assets in a single-operation enterprise). In those circumstances, the asset group for that long-lived asset includes all assets and liabilities of the enterprise.

.14 An example of a situation where a liability would be included in an asset group is a mortgage for which the building is the only source of cash flow to pay the liability. If other cash flows are available to pay the liability, the mortgage would not be grouped with the building for purposes of impairment.

.15 Goodwill is included in the carrying amount of an asset group to be tested for impairment only if the asset group is or includes a reporting unit (see GOODWILL AND OTHER INTANGIBLE ASSETS, Section 3062). Goodwill is not included in the carrying amount of a lower-level asset group that includes only part of a reporting unit. Estimates of future cash flows used to test that lower-level asset group for recoverability are not reduced to reflect the fact that goodwill is not included in the carrying amount of the asset group.

.16 An asset group may include assets (such as accounts receivable and inventory) not covered by this Section, as well as liabilities (such as accounts payable and long-term debt). With the exception of goodwill (see GOODWILL AND OTHER INTANGIBLE ASSETS, Section 3062), the carrying amounts of these assets and liabilities are evaluated (in accordance with generally accepted accounting principles) prior to testing the asset group for recoverability. (For example, loans would be evaluated in accordance with IMPAIRED LOANS, Section 3025, the allowance for doubtful accounts would be evaluated in accordance with ACCOUNTS AND NOTES RECEIVABLE, Section 3020, and long-lived assets held for sale would be evaluated in accordance with DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS, Section 3475.)

.17 An impairment loss for an asset group reduces only the carrying amounts of long-lived assets held for use and not of any other assets or liabilities of the asset group. The loss is allocated to the long-lived assets of the group on a pro rata basis using the relative carrying amounts of those assets. However, the loss allocated to an individual long-lived asset of the group does not reduce the carrying amount of that asset below its fair value, whenever the fair value is determinable without undue cost and effort.

Cash flow test for recoverability

.18 ♦ *Estimates of future cash flows used to test the recoverability of a long-lived asset should include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with, and that are expected to arise as a direct result of, its use and eventual disposition. These cash flows include the principal amount of any liabilities included in* *the asset group, but not interest that will be recognized as an expense when incurred.* [APRIL 2003]

.19 Estimates of future cash flows used to test the recoverability of a long-lived asset incorporate the enterprise's own assumptions about its use, considering all available evidence. The assumptions used in developing those estimates are reasonable in relation to the assumptions used in developing other information used by the enterprise for comparable periods, such as internal budgets and projections, accruals related to incentive compensation plans, or information communicated to others. However, if alternative courses of action to recover the carrying amount are under consideration (such as the future sale of the asset), or if a range is estimated for the amount of possible future cash flows associated with the likely course of action, the likelihood of those possible outcomes is considered. That assessment is not revised for changes after the balance sheet date (such as a subsequent decision to sell the asset). A probability-weighted approach may be useful in considering the likelihood of these possible outcomes.

.20 The remaining useful life of a long-lived asset to the enterprise is used to estimate the future cash flows for purposes of testing its recoverability. The remaining useful life of an asset group is based on the remaining useful life of the primary asset of the group. This is the principal long-lived tangible asset being depreciated (or intangible asset being amortized) that is the most significant component asset from which the asset group derives its cash-flow-generating capacity. (An asset not being amortized, such as land or an indefinite-lived intangible asset, cannot be the primary asset of the group.) Factors that an enterprise generally considers in determining whether a long-lived asset is the primary asset of an asset group include the following:

(a) whether other assets of the group would have been acquired by the enterprise without the asset;

(b) the level of investment that would be required to replace the asset; and

(c) the remaining useful life of the asset relative to other assets of the group.

If the primary asset is not the asset of the group with the longest remaining useful life, estimates of future cash flows for the group assume the sale of the group at the end of the remaining useful life of the primary asset.

.21 Estimates of future cash flows used to test the recoverability of a long-lived asset that is in use, including one for which development is substantially complete, are based on its existing service potential at the date it is tested. Service potential encompasses the remaining useful life, cash-flow-generating capacity and, for tangible assets, physical output capacity. The estimates include cash flows associated with future expenditures necessary to maintain the existing service potential of a long-lived asset, including those that replace the service potential of its component parts (for example, the roof of a building) and component assets other than the primary asset of an asset group. Cash flows associated with future capital expenditures that would increase the service potential are excluded from estimates of future cash flows used to test recoverability.

.22 Estimates of future cash flows used to test the recoverability of a long-lived asset that is under development are based on its expected service potential when development is substantially complete. These estimates include cash flows associated with all future expenditures necessary to complete its development, including interest payments that will be capitalized as part of its cost.

.23 If a long-lived asset that is under development is part of an asset group that is in use, estimates of future cash flows used to test the recoverability of that group include the cash flows associated with future expenditures necessary to maintain the existing service potential of the group, as well as the cash flows associated with all future expenditures necessary to substantially complete the asset that is under development.

DISCLOSURE

.24 ♦ *The financial statements should disclose the following information in the period in which an impairment loss is recognized:*

(a) *a description of the impaired long-lived asset and the facts and circumstances leading to the impairment;*

(b) *if not separately presented on the face of the income statement, the amount of the impairment loss and the caption in the income statement that includes that loss;*

(c) *the method or methods for determining fair value of the impaired long-lived asset (whether based on a quoted market price, prices for similar assets, or another valuation technique); and*

(d) *if applicable, the segment in which the impaired long-lived asset is reported under SEGMENT DISCLOSURES, Section 1701.* [APRIL 2003]

TRANSITIONAL PROVISIONS

.25 This Section applies prospectively to fiscal years beginning on or after April 1, 2003. Earlier adoption is encouraged.

.26 An enterprise that elects early adoption applies this Section retroactively to the beginning of its current fiscal year and restates prior interim financial statements of that year.

.27 Paragraph 3063.02(h) applies when an entity adopts FINANCIAL INSTRUMENTS — RECOGNITION AND MEASUREMENT, Section 3855.

APPENDIX

This Appendix is an integral part of this Section.

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ESTIMATING FAIR VALUE

A1 Fair value can be characterized as the amount at which an item could be bought or sold in a current transaction between willing parties (that is, other than in a forced or liquidation sale). The fair value of a disposal group is the amount at which the group as a whole could be bought or sold in a current single transaction between willing parties, and would not necessarily equate to the sum of the fair values of the individual assets and liabilities of the group.

A2 Quoted market prices in active markets are the best evidence of fair value and are, therefore, used as the basis for fair value measurement, when available.

A3 When quoted market prices are not available, estimates of fair value are based on the best information available, including prices for similar items and the results of other valuation techniques. Valuation techniques used would be consistent with the objective of measuring fair value.

USING PRESENT VALUE TO ESTIMATE FAIR VALUE [1a]

A4 A present value technique is often the best available technique with which to estimate the fair value of a long-lived asset and generally includes the following elements:

(a) an estimate of the series of future cash flows at different times;

(b) expectations about possible variations in the amount or timing of those cash flows;

(c) the time value of money, represented by the risk-free rate of interest; and

(d) the price for bearing the uncertainty inherent in the asset or liability.

Other factors, if identifiable, include illiquidity and market imperfections.

A5 For purposes of this Section, the only objective of present value is to estimate fair value. Present value should attempt to capture the elements that, taken together, would comprise a market price if one existed (i.e., fair value).

A6 The techniques used to estimate future cash flows and interest rates will vary from one situation to another depending on the circumstances surrounding the asset or liability in question. However, certain general principles govern any application of present value techniques in measuring assets or liabilities:

(a) To the extent possible, estimated cash flows and interest rates reflect assumptions about the future events and uncertainties that would be considered in deciding whether to acquire an asset or group of assets in an arm's length transaction for cash.

(b) Interest rates used to discount cash flows reflect assumptions that are consistent with those inherent in the estimated cash flows. Otherwise, the effect of some assumptions will be double-counted or ignored. For example, an interest rate of 12 percent might be applied to contractual cash flows of a loan. That rate reflects expectations about future defaults from loans with particular characteristics. That same 12 percent rate would not be used to discount expected cash flows because those cash flows already reflect assumptions about future defaults.

(c) Estimated cash flows and interest rates are free from both bias and factors unrelated to the asset, liability, or group of assets or liabilities in question. For example, deliberately understating estimated net cash flows to enhance the apparent future profitability of an asset introduces a bias into the measurement.

(d) Estimated cash flows or interest rates reflect the range of possible outcomes rather than a single most-likely, minimum, or maximum possible amount.

A7 Cash flow estimates incorporate assumptions that marketplace participants would use in their estimates of fair value whenever that information is available without undue cost and effort. Otherwise, an enterprise may use its own assumptions. The use of an enterprise's own assumptions about future cash flows is compatible with an estimate of fair value, as long as there are no contrary data indicating that marketplace participants would use different assumptions. If such data exists, the enterprise must adjust its assumptions to incorporate that market information.

A8 An enterprise's best estimate of the present value of cash flows will not necessarily equal the fair value of those uncertain cash flows. There are several reasons why an enterprise might expect to realize or pay cash flows that differ from those expected by others in the marketplace. These include:

(a) The enterprise's managers might intend different use or settlement than that anticipated by others. For example, they might intend to operate a property as a bowling alley, even though others in the marketplace consider its highest and best use to be a parking lot.

(b) The enterprise's managers may prefer to accept risk of a liability (like a product warranty) and manage it internally, rather than transferring that liability to another enterprise.

(c) The enterprise might hold special preferences, like tax or zoning variances, not available to others.

(d) The enterprise might hold information, trade secrets, or processes that allow it to realize (or avoid paying) cash flows that differ from others' expectations.

(e) The enterprise might be able to realize or pay amounts through use of internal resources. For example, an enterprise that manufactures materials used in particular processes acquires those materials at cost, rather than the market price charged to others. An enterprise that chooses to satisfy a liability with internal resources may avoid the markup or anticipated profit charged by outside contractors.

A9 Cash flow estimates are based on reasonable and supportable assumptions and consider all available evidence. The weight given to the evidence is commensurate with the extent to which the evidence can be verified objectively.

A10 Two present value techniques may be used to measure the fair value of an asset. These are traditional present value and expected present value.

TRADITIONAL PRESENT VALUE TECHNIQUE

A11 The traditional approach uses a single set of cash flows, either contractual cash flows or an estimate of the single most likely amount (best estimate). These cash flows are discounted at a single interest rate, commensurate with the risk. This assumes that a single interest rate can reflect all the expectations about the future cash flows and the appropriate risk premium. It also assumes that the appropriate risk premium for the specific asset can be identified.

A12 An enterprise's borrowing rate is rarely, if ever, appropriate for the measurement of that enterprise's assets. The uncertainties and risks embodied in a particular asset are usually unrelated to the risks assumed by those who hold the enterprise's obligations as assets. There are cases in which recognition of a liability and its measurement using present value is accompanied by recognition of an asset measured at a similar amount. However, in those situations, present value is used only to measure the liability. The recorded amount of the asset presumably is its fair value, as evidenced by the value of the debt incurred to acquire the asset.

A13 The traditional approach is useful for many measurements, especially those for which comparable assets can be observed in the marketplace. However, this approach does not provide the tools needed to address some complex measurement problems. For long-lived assets for which no market exists for the item or for comparable items, and that have uncertainties both in timing and amount, expected present value would often be the appropriate technique.

EXPECTED PRESENT VALUE TECHNIQUE

A14 The expected present value approach uses multiple cash flow scenarios that reflect the range of possible outcomes. Only the third factor listed in paragraph 3063.A4 (the time value of money, represented by the risk-free rate of interest) is included in the discount rate; the other factors cause adjustments in arriving at risk-adjusted expected cash flows.

A15 Probabilities are applied to each cash flow scenario to arrive at expected cash flows (before adjusting for risk, see paragraphs 3063.A19-.A25). For example, a cash flow for a certain year might be $100, $200 or $300 with probabilities of 10 percent, 60 percent and 30 percent respectively. The expected cash flow is $220 [calculated as ($100 x 0.1) + ($200 x 0.6) + ($300 x 0.3)], compared to a best estimate or most likely amount of $200.

A16 Many estimates developed in current practice already incorporate the elements of expected cash flows informally. In addition, accountants often face the need to measure an asset or liability using limited information about the probabilities of possible cash flows. For example, an accountant might be confronted with the following situations:

(a) The estimated amount falls somewhere between $50 and $250, but no amount in the range is more likely than any other amount. Based on that limited information, the estimated expected cash flow is $150 [(50 + 250) ÷ 2].

(b) The estimated amount falls somewhere between $50 and $250, and the most likely amount is $100. However, the probabilities attached to each amount are unknown. Based on that limited information, the estimated expected cash flow is $133.33 [(50 + 100 + 250) ÷ 3].

(c) The estimated amount will be $50 (10 percent probability), $250 (30 percent probability), or $100 (60 percent probability). Based on that limited information, the estimated expected cash flow is $140 [(50 x 0.1) + (250 x 0.3) + (100 x 0.6)].

A17 Those familiar with statistical analysis may recognize the cases above as simple descriptions of (a) uniform, (b) triangular, and (c) discrete distributions. In each case, the estimated expected cash flow is likely to provide a better estimate of fair value than the minimum, most likely, or maximum amount taken alone.

A18 Like any accounting measurement, the application of an expected cash flow approach is subject to a cost / benefit constraint. In some cases, an enterprise may have access to considerable data and may be able to develop many cash flow scenarios. In other cases, an enterprise may not be able to develop more than general statements about the variability of cash flows without incurring considerable cost. The accounting problem is to balance the cost of obtaining additional information against the additional reliability that information will bring to the measurement. The Board recognizes that judgments about relative costs and benefits vary from one situation to the next and involve financial statement preparers, their auditors, and the needs of financial statement users.

RISK AND UNCERTAINTY

A19 An estimate of fair value should include the price that marketplace participants are able to receive for bearing the uncertainties in cash flows — the adjustment for risk — if the amount is identifiable, measurable, and significant. An arbitrary adjustment for risk, or one that cannot be evaluated by comparison to marketplace information, introduces an unjustified bias into the measurement. On the other hand, excluding a risk adjustment (if it is apparent that marketplace participants include one) would not produce a measurement that faithfully represents fair value. There are many techniques for estimating a risk adjustment, including matrix pricing, option-adjusted spread models, and fundamental analysis. However, in many cases a reliable estimate of the market risk premium may not be obtainable or the amount may be small relative to potential measurement error in the estimated cash flows. In such situations, the present value of expected cash flows, discounted at a risk-free rate of interest, may be the best available estimate of fair value in the circumstances.

A20 Present value measurements, like many other accounting measurements, occur under conditions of uncertainty. In this Appendix, the term uncertainty refers to the fact that the cash flows used in a present value measurement are estimates, rather than known amounts. (Even contractual amounts, like the payments on a loan, are uncertain because some borrowers default.) That uncertainty has accounting implications because it has economic consequences. Businesses and individuals routinely enter into transactions based on expectations about uncertain future events. The outcome of those events will place the enterprise in a financial position that may be better or worse than expected, but until the uncertainties are resolved, the enterprise is at risk.

A21 In common usage, the word "risk" refers to any exposure to uncertainty in which the exposure has potential negative consequences. This broad use of the term often leads to misunderstandings. Risk is a relational concept, and a particular risk can only be understood in context. For example, consider two lenders that have each made 1,000 loans. Each lender could describe itself as being at risk with regard to the loans but their respective descriptions may have very different meanings. The first lender might describe itself as at risk that some of the 1,000 loans will default. The second lender might observe that it expects 150 loans to default and has set the interest rate accordingly. The second lender might then describe its risk as the chance that actual defaults will vary from the expected 150. Even though the two are describing the same economic activity (lending), they are likely to misunderstand one another unless each clearly describes the uncertainty and related exposure.

A22 In most situations, marketplace participants are said to be risk averse or perhaps loss averse. A risk-averse investor prefers situations with a narrower range of uncertainty over situations with greater range of uncertainty relative to an expected outcome. A loss-averse investor places relatively greater importance on the likelihood of loss than on the potential for gain. Both types of marketplace participants seek compensation, referred to as a risk premium, for accepting uncertainty. Stated differently, given a choice between:

(a) an asset with expected cash flows that are uncertain, and

(b) another asset with cash flows of the same expected amount but no uncertainty,

marketplace participants will place a higher value on (b) than (a). Similarly, marketplace participants generally seek to demand more to assume a liability with expected cash flows that are uncertain than to assume a liability with cash flows of the same expected amount but no uncertainty. This phenomenon can also be described with the financial axiom, "the greater the risk, the greater the return."

A23 The behaviour of a risk-averse marketplace participant can be illustrated by comparing two assets. Asset A has a promised cash flow of $10,000, due 10 years hence, and there is no uncertainty about the cash flow. Asset B has an expected cash flow of $10,000, due 10 years hence; however, the expected cash flows are uncertain. Actual cash flows from Asset B may be as high as $12,000 or as low as $8,000, or some other amount within that range. If the risk-free rate of interest for 10-year instruments is five percent, a risk-averse marketplace participant would pay about $6,139 for Asset A. The risk-averse individual would pay something less for Asset B because of the uncertainty involved. (While the expected cash flow of $10,000 incorporates the uncertainty in cash flows from Asset B, that amount does not incorporate the premium that marketplace participants demand for bearing that uncertainty.) There are markets, like lotteries, in which participants are risk seeking rather than risk averse. In those markets, participants pay more than an asset's expected cash flow in the hope of reaping a windfall. While they exist, those markets are not typical of situations encountered in financial reporting.

A24 The objective of including uncertainty and risk in accounting measurements is to imitate, to the extent possible, the market's behaviour toward assets and liabilities with uncertain cash flows. This should not be confused with notions of bias designed to intentionally understate the reported amount of an asset or overstate the reported amount of a liability.

A25 If prices for an asset or liability or an essentially similar asset or liability can be observed in the marketplace, there is no need to use present value measurements. (The marketplace assessment of present value is already embodied in the price.) However, if observed prices are unavailable, present value measurements are often the best available technique with which to estimate what a price would be. An enterprise typically will be able to estimate the expected cash flows from an asset or liability, but the appropriate risk premium consistent with fair value may be difficult to determine.

ILLUSTRATIVE EXAMPLES

This material is illustrative only.

These examples illustrate how the accounting treatment specified in this Section might be applied in particular situations. Matters of principle relating to particular situations should be decided in the context of the Section.

Example 1 — Allocating an impairment loss

B1 This example illustrates the allocation of an impairment loss to the long-lived assets of an asset group.

B2 An enterprise owns a manufacturing facility that, together with other assets, is tested for recoverability as a group. In addition to long-lived assets (Assets A-D), the asset group includes inventory, which is reported at the lower of cost or market, and other current assets and liabilities that are not covered by this Section. The $2.75 million aggregate carrying amount of the asset group is not recoverable and exceeds its fair value by $600,000. In accordance with paragraph 3063.17, the impairment loss of $600,000 would be allocated as shown below to the long-lived assets of the group.

($ thousands)

Asset group	Carrying amount	Pro rata allocation factor	Allocation of impairment (loss)	Adjusted carrying amount
Current assets	$ 400	—	—	$ 400
Liabilities	(150)	—	—	(150)
Long-lived assets:				
Asset A	590	24%	$(144)	446

Asset B	780	31	(186)	594
Asset C	950	38	(228)	722
Asset D	180	7	(42)	138
Subtotal — long-lived assets	2,500	100	(600)	1,900
Total	$2,750	100%	$(600)	$2,150
	=====	====	=====	=====

B3 If the fair value of an individual long-lived asset of an asset group is determinable without undue cost and effort and exceeds the adjusted carrying amount of that asset after an impairment loss is allocated initially, the excess impairment loss initially allocated to that asset would be reallocated to the other long-lived assets of the group. For example, if the fair value of Asset C is $822,000, the excess impairment loss of $100,000 initially allocated to that asset (based on its adjusted carrying amount of $722,000) would be reallocated, as shown below, to the other long-lived assets of the group on a pro rata basis using the relative adjusted carrying amounts of those assets.

($ thousands)

Long-lived assets of asset group	Adjusted carrying amount	Pro rata reallocation factor	Reallocation of excess impairment (loss)	Adjusted carrying amount after reallocation
Asset A	$ 446	38%	$ (38)	$ 408
Asset B	594	50	(50)	544
Asset D	138	12	(12)	126
Subtotal	1,178	100%	(100)	1,078
		====		
Asset C	722		100	822
Total — long-lived assets	$1,900		$ 0	$1,900
	=====		===	=====

Example 2 — Probability-weighted cash flows

B4 This example illustrates the use of a probability-weighted approach for developing estimates of future cash flows used to test a long-lived asset for recoverability when alternative courses of action are under consideration.

B5 At December 31, 20X2, a manufacturing facility with a carrying amount of $48 million is tested for recoverability. At that date, two courses of action to recover the carrying amount of the facility are under consideration — sell in two years or sell at the end of its remaining useful life of 10 years. The facility has identifiable cash flows that are largely independent of the cash flows of other assets.

B6 The following table shows the range and probability of possible estimated cash flows expected to result from the use and eventual disposition of the facility, assuming that it is sold at the end of two years or it is sold at the end of 10 years. Among other things, the range of possible estimated cash flows considers future sales levels (volume and price) and associated manufacturing costs in varying scenarios that consider the likelihood that existing customer relationships will continue, as well as future economic (market) conditions. The probability assessments consider all information available without undue cost and effort. Such assessments are by their nature subjective and, in many situations, may be limited to management's best judgment about the probabilities of the best, worst, and most likely scenarios.

($ millions)

Course of action	Cash flow estimate (use)	Cash flow estimate (disposition)	Cash flow estimate	Probability assessment	Probability-weighted cash flows
Sell in 2 years	$ 8	$30	$38	20%	$ 7.6
	11	30	41	50	20.5
	13	30	43	30	12.9
					$41.0
					====
Sell in 10 years	$36	$ 1	$37	20%	$ 7.4
	48	1	49	50	24.5
	55	1	56	30	16.8
					$48.7
					====

B7 In computing the future cash flows used to test the facility for recoverability, the enterprise concludes that there is a 60 percent probability that the facility will be sold at the end of two years and a 40 percent probability that the facility will continue to be used for its remaining estimated useful life of 10 years. The following table shows the computation of future cash flows based on the probability of those alternative courses of action. [1b] As shown, those future cash flows are $44.1 million (undiscounted). Therefore, the carrying amount of the facility of $48 million would not be recoverable.

($ millions)

Course of action	Probability-weighted cash flows	Probability assessment (course of action)	Expected cash flows
Sell in 2 years	$41.0	60%	$24.6

Sell in 10 years	48.7	40	19.5
			$44.1
			====

Example 3 — Cash flow test for recovery

B8 A long-lived asset that is under development may be part of an asset group that is in use. In that situation, estimates of future cash flows used to test the recoverability of that group include the cash flows associated with future expenditures necessary to maintain the existing service potential of the group, as well as the cash flows associated with future expenditures necessary to substantially complete the asset that is under development.

B9 An enterprise engaged in mining and selling phosphate estimates future cash flows from its commercially minable phosphate deposits in order to test the recoverability of the asset group that includes the mine and related long-lived assets (plant and equipment). Deposits from the mined rock must be processed in order to extract the phosphate. As the active mining area expands along the geological structure of the mine, a new processing plant is constructed near the production area. Depending on the size of the mine, extracting the minable deposits may require building numerous processing plants over the life of the mine. In testing the recoverability of the mine and related long-lived assets, the estimates of future cash flows from its commercially minable phosphate deposits would include cash flows associated with future expenditures necessary to build all of the required processing plants.

Example 4 — Applying present value

B10 The following five assets each have an undiscounted measurement of $10,000:

Asset A: An asset with a fixed contractual cash flow of $10,000 due in one day. The cash flow is certain of receipt.

Asset B: An asset with a fixed contractual cash flow of $10,000 due in 10 years. The cash flow is certain of receipt.

Asset C: An asset with a fixed contractual cash flow of $10,000 due in one day. The amount that ultimately will be received is uncertain. It may be less than $10,000 but will not be more.

Asset D: An asset with a fixed contractual cash flow of $10,000 due in 10 years. The amount that ultimately will be received is uncertain. It may be less than $10,000 but will not be more.

Asset E: An asset with an expected cash flow of $10,000 due in 10 years. The amount that ultimately will be received is uncertain, but it may be as high as $12,000, as low as $8,000, or some other amount within that range.

B11 Four of those assets have the same contractual cash flow ($10,000), and the expected cash flow from the fifth is also that amount. For Asset A, the promise of a certain amount tomorrow, the nominal amount is very close to fair value. The other assets need further adjustment to arrive at an accounting measurement that embodies the differences between them.

Time value of money

B12 Assets B, D, and E represent cash to be received 10 years hence, while Assets A and C promise cash tomorrow. Using the rate of interest for 10-year default risk-free assets (five percent), the present value of Assets B, D, and E is $6,139. For Asset B, the promise of an amount certain of receipt in 10 years, that measurement is likely to be a good estimate of fair value.

Adjustment for expectations

B13 Assets A and C each promise $10,000 tomorrow, but no rational enterprise would pay the same price for each promise. While the buyer might pay close to $10,000 for Asset A, it would pay no more than it expects to collect from Asset C. If the buyer expects that, on average, promises like Asset C pay 80 percent of the amount promised, the buyer would not expect to pay more than $8,000 for Asset C. If the buyer expects a similar performance from promises like Asset D, the buyer would expect to pay no more than $4,911 (Asset B — $6,139 x 80 percent). The expected cash flow from Asset E already includes the probability-weighted average of expectations, so no further adjustment is necessary. The five assets are measured at four different amounts (before adjustment for risk).

Asset A: A certain cash flow of $10,000 due in one day — measured at $10,000

Asset B: A certain cash flow of $10,000 due in 10 years — measured at $6,139

Asset C: An uncertain cash flow of $10,000 due in one day — measured at $8,000

Asset D: An uncertain cash flow of $10,000 due in 10 years — measured at $4,911

Asset E: An expected cash flow of $10,000 due in 10 years — measured at $6,139.

Risk premium

B14 Marketplace participants typically seek compensation for accepting uncertainty. A risk-averse investor would usually demand some incentive before choosing to invest in Asset C (which may return more or less than the expected $8,000) or Asset E rather than investing a comparable amount in Asset A (which is certain to return the promised amount). The amounts assigned to risk premiums in this example are provided to illustrate the computation rather than to indicate amounts that might be applied in actual measurements.

B15 Computationally, the steps described in the preceding paragraphs could be included as adjustments to cash flows or to the interest rate, as illustrated below:

Components in cash flows

	Asset A certain tomorrow	Asset B certain — 10 years	Asset C uncertain tomorrow	Asset D uncertain — 10 years	Asset E uncertain — 10 years

Contractual (promised) cash flow	$10,000	$10,000	$10,000	$10,000	—
Adjustment to reflect expectations	—	—	(2,000)	(2,000)	—
Expected cash flow	$10,000	$10,000	8,000	8,000	$10,000
Adjustment to reflect risk premium	—	—	(50)	(500)	(500)
Adjusted cash flows	$10,000	$10,000	$7,950	$7,500	$ 9,500
	======	======	=====	=====	=====
Present value at 5% (risk-free rate)	$10,000	$6,139	$7,950	$4,604	$5,832
	======	=====	=====	=====	=====

Components in interest rates

	Asset A	Asset B	Asset C	Asset D	Asset E
Time value element	—	5.000%	—	5.000%	5.000%
Adjustment to reflect expectations	—	—	—	2.370	—
Adjustment to reflect risk premium	—	—	—	0.695	0.540
Effective interest rate		5.000%		8.065%	5.540%
		======		======	======

Example 5 — Expected present value technique

B16 This example illustrates the application of an expected present value technique to estimate the fair value of a long-lived asset in the absence of an observable market price. [2b] It is based on the facts provided for the manufacturing facility in Example 2.

B17 Consistent with an objective of measuring fair value, the enterprise's estimates of future cash flows used to test the manufacturing facility for recoverability in Example 2 are adjusted to incorporate assumptions that, based on available information, marketplace participants would use in their estimates of the fair value of the asset. The net effect of those adjustments is to increase the enterprise's estimates of future cash flows (on an undiscounted basis) by approximately 15 percent. [3b]

B18 The following table shows by year the range and probability of possible cash flows expected to result from the use and eventual disposition of the facility over its remaining useful life of 10 years (Example 2), adjusted for market assumptions. It also shows by year the computation of expected cash flows.

($ millions)

Year	Total cash flow estimate (market)	Probability assessment	Expected cash flows
1	$4.6	20%	$0.9
	6.3	50	3.2
	7.5	30	2.3
			$6.4
2	$4.6	20%	$ 0.9
	6.3	50	3.2
	7.5	30	2.3
			$6.4
3	$4.3	20%	$0.9
	5.8	50	2.9
	6.7	30	2.0
			$5.8
4	$4.3	20%	$0.9
	5.8	50	2.9
	6.7	30	2.0
			$5.8
5	$4.0	20%	$0.8
	5.4	50	2.7
	6.4	30	1.9
			$5.4
6	$4.0	20%	$0.8
	5.4	50	2.7
	6.4	30	1.9
			$5.4
7	$3.9	20%	$0.8
	5.1	50	2.6
	5.6	30	1.7

			$5.1
8	$3.9	20%	$0.8
	5.1	50	2.6
	5.6	30	1.7
			$5.1
9	$3.9	20%	$0.8
	5.0	50	2.5
	5.5	30	1.7
			$5.0
10	$4.9	20%	$1.0
	6.0	50	3.0
	6.5	30	2.0
			$6.0

B19 The following table shows the computation of the present value of the expected cash flows; that is, the sum of the present values of the expected cash flows by year, which are calculated by discounting those cash flows at a risk-free rate. As shown, the expected present value is $42.3 million. The enterprise would recognize an impairment loss of $5.7 million ($48 million less $42.3 million).

($ millions)

Year	Expected cash flows	Risk-free rate of interest	Present value
1	$6.4	5.0%	$6.1
2	6.4	5.1	5.8
3	5.8	5.2	5.0
4	5.8	5.4	4.7
5	5.4	5.6	4.1
6	5.4	5.8	3.9
7	5.1	6.0	3.4

8	5.1	6.2	3.2
9	5.0	6.4	2.9
10	6.0	6.6	3.2
Expected present value			$42.3

Appendix I

CAPITALIZATION POLICY

2.1 Introduction

This chapter covers the capitalization policies related to the capital additions acquired or constructed, defining capital versus maintenance expenditures, the basis of capital costs, and the classification for certain types of capital expenditures.

Matching Costs

Terasen Gas policy is to distribute expenditures as equitably as possible among present and future customers by matching capitalized costs to the accounting period in which associated benefits accrue. This is accomplished in accordance with the Company's depreciation/amortization practices, which are subject to BCUC regulations.

Capitalization

All costs associated with the acquisition and construction of capital assets are capitalized.

Capital Asset

Expenditures are classified as a capital asset following these criteria:

- the expenditure must provide, or contribute, benefits to Terasen Gas for a service life greater than one year
- the expenditure must result in, or contribute toward, acquisition of an economic resource or asset over which Terasen Gas has a legally enforceable claim to a service potential, right or specific benefit. Terasen Gas must also control the asset
- the expenditure must be expected to result in, or contribute toward, a benefit which leads with a reasonable degree of certainty to recover through potential sales of service or products, or which is required to meet safety or governmental regulations
- the expenditure must meet the minimum capitalization level requirements

2.2 Minimum Capitalization Level

Minimum Level

For direct costs incurred in acquiring or constructing the addition or replacement of a PRU which falls into one of the categories, is capitalized if the cost of the PRU exceed the specified limits:

	TGI $	TGVI/TGW $
Tools and equipment	1,000	500
Furniture and equipment	1,000	500

Purchased computer software/hardware	1,000	500
Other general plant equipment	1,000	500
In-house developed computer software and/or based on assessment of individual projects	10,000	10,000

Concept of PRUs

The concept of Property Retirement Units (PRUs) is defined in the Company's PRU Catalogue, and repeated in this Manual under Appendices A – Glossary. The PRU Catalogue is an integral part of the Capitalization Policy as this defines what expenditures are considered capital.

2.3 Second-Hand Plant

When second-hand plant is acquired in such physical condition that extensive repairs are necessary to bring it up to current standards, the cost of such repairs shall be considered capital.

Second-hand plant acquired does not include plant previously owned by the company.

2.4 Capital Versus Maintenance

PRU Additions

The PRU outlines/describes expenditures for capitalization purposes for a unit of property in the asset subledger.

Maintenance

Items smaller than a component outlined/described in the PRU or an item whose acquisition cost is lower than the minimum capitalization level is charged to maintenance.

Expenditure on Existing PRUs

Expenditure on existing PRUs in service is capitalized if the expense results in:

- a replacement of the entire PRU or
- a substantial improvement or betterment of the PRU

Classification of Expenses

Expenditures during ownership of capital assets are classified as:

- maintenance and repairs
- improvements and additions
- rehabilitation/major renewals
- replacements and retirements

these expenditures are defined in further detail below to set them apart and to distinguish the cost as capital or a maintenance charge.

2.4.1 Maintenance and Repairs

Concept

Maintenance costs are expenditures made to keep the asset in good condition (preventive); while repair costs are made to put the asset back into good working condition (curative).

Does not Affect

Maintenance and repair costs are not expected to prolong the normal life of an asset (PRU), or materially add to its service value. As no additional benefits are anticipated, the costs of maintenance and repairs are charged to maintenance in the current accounting period.

2.4.2 Improvements and Additions

Substantial Betterments

Improvements or substantial betterments refer to capital expenditures on existing PRUs which:

- materially add to the service value of the PRU(s); or
- materially extend the normal service life of the PRU(s)

Increase in Service Value

The service value of a PRU may be increased through expansion and extension where there is an increase in the physical size of an asset. For example, a new wing is added to a building or more equipment is added to an existing capital asset.

Increase in Service Life

The normal service life of a PRU is increased through substitution where there is an increase in the quality of an asset. For example, paving a gravel parking lot increases the quality of an existing asset.

Consult Asset Accounting

When in doubt about each case in Section 2.4, consult Asset Accounting to assist you in deciding the appropriate accounting treatment.

Significant cost and long life do not by themselves decide that a replacement cost can be capitalized; e.g. the cost to replace a roof with the same kind of materials would be considered maintenance expense.

2.4.3 Major Renewals and Repairs

Expenditures to restore or improve buildings or equipment can be charged to capital assets as part of the cost, provided that;

- the costs of renewals or repair, which means the costs of material plus the cost of labour used in the process, exceeds fifty percent (50%) of the replacement cost of a new plant unit of the same kind and class
- the costs of dismantling and/or repairing old parts reused, are excluded and charged to expense
- the renewed or repaired plant unit (PRU) is accounted for as a capital addition, and the old plant unit PRU is accounted for as retired from service

Consult Asset Accounting to assist in the determining the appropriate accounting treatment.

2.4.4 Replacements and Retirements

Complete PRU

Replacement of a complete PRU:

- the original cost of the old asset (PRU) is retired and the cost of the new item is capitalized

Part of PRU is Maintenance

Replacements of parts and (less than a PRU):

- the costs of replacing parts and components of a PRU is accounted for as maintenance expense. Replacements of parts and components here means to restore the PRU to its original condition, and keep it in efficient operating condition

Extensive Replacement

Extensive replacements of part (less than a PRU) could be considered as capital improvement/substantial betterment.

The cost incurred to replace components or part of a PRU, which according to government or agency regulation creates a health or safety hazard, does not automatically qualify for capitalization. Such projects must meet the 'substantial betterment' criteria on an individual PRU, project/location basis.

In each case, please consult Asset Accounting.

2.5 Basis of Cost

At Cost

Expenditure for capital assets are recorded at the historic cost to Terasen Gas. Cost includes direct expenditures related to the acquisition/construction as well as a proportionate allocation of overhead and, where applicable, allowance for funds used during construction charges.

Construction by Terasen Gas

- If the capital asset is constructed for or by Terasen Gas, the construction costs including labour, material and supplies, contract work, special machine and heavy work equipment service, insurance, damages, privileges, a proportionate allocation for overhead, and where applicable, allowance for funds used during construction.
- When a project necessitates the purchase of PRU equipment items such as office equipment, heavy work equipment, transportation equipment to be used exclusively for the project, the cost of such equipment is, for the duration of the project, charged to construction, subject to approval by Asset Accounting.

Acquisition from Other Company

Where Terasen Gas purchases capital assets from another company, the difference between the purchase price paid by Terasen Gas and the original cost of the capital asset, less the accumulated depreciation/amortization, must be accounted for as non-utility plant. This is defined under capital code description account G/L 10090 – "Gas Plant Not in Rate Base", and Section 2.11 of this Chapter.

Surplus-to-Project Material

- When a project is completed, surplus inventory items, considered re-usable, are returned to stores by crediting the project at the prevailing inventory unit cost.
- Non-inventory items that can be identified:
  - for future project use, scheduled to begin with two years are taken into Central Stores by crediting the project at fair market value; or
  - as office, heavy work or transportation equipment which were initially purchased exclusively for project use and now considered re-usable as general plant equipment, are transferred from WIP account to plant-in-service at fair market value, provided it meets the minimum capitalization level. If it is not considered re-usable as general plant equipment, it must be disposed of through re-sale and the proceeds credited to the project.

2.6 Capitalized Overhead

Cost Classification

Costs which cannot be directly identified with individual construction projects are collected by a cost centre and classified as operating /maintenance expense or capitalized overhead.

Allocation Predetermined

Overhead will be capitalized on the basis of predetermined rates established by Finance and reviewed annually, to ensure that the apportionment of Operating and Maintenance expense to capitalized overhead is reasonable and consistent.

Capitalization rates will be calculated annually by Finance, based initially on budgeted costs with revision at year end, to actual costs where the change is considered to be material.

Certain administrative/common costs are capitalized at fixed maximum rates, which do not vary with construction levels and will not be recalculated annually.

Distributed to Plant

The resultant overheads capitalized are charged monthly to account 10098 (Overhead Charged to Construction). At year-end the overheads capitalized balance will be distributed to the appropriate plant accounts.

Quarterly/Annual Review

On a quarterly basis, actual costs are substituted in the calculation of capitalization rates to monitor the impact of actual construction activity.

At the end of the year, if there are substantial changes from budget in construction activity, which results in a significant change in overheads capitalized, the actual rates as calculated are used to recalculate the overheads capitalized. Account 10098 will be adjusted accordingly.

Plant Not Applicable

Overhead is NOT applied to:

- removal/dismantling costs
- corporate capital additions

2.7 Allowance for Funds Used During Construction (AFUDC)

Policy

AFUDC is capitalized on projects under construction whose costs are greater than $50,000 each and which are expected to take three (3) or more months to construct. AFUDC is the cost of capital that is the cost of borrowed funds and a reasonable rate on other funds such as equity, used for the purpose of construction.

Rate Determined

The AFUDC rate is the return on rate base for Terasen Gas as approved by BCUC.

AFUDC Applied

AFUDC is applied to both specific and certain recurring plant expenditures based on previous month-to-date total direct and overhead costs, less contributions in aid of construction received, if any.

AFUDC Begins

AFUDC will commence on the date the project is approved for and ends when the project is placed into service. One-half the rate is applied to eligible projects which start/completed up to the 15th of the month, and the full rate thereafter.

Preliminary Charges

Related preliminary engineering and/or research and development expenditures, accumulated to date of construction are eligible for AFUDC from date of construction.

Adjustment

AFUDC applied to specific projects, may be subject to recalculation or reversal, if the AFUDC criteria is not met or the AFUDC rate is adjusted.

AFUDC Not Applied

AFUDC is not applied on expenditures in the following capital asset classifications:

- capital assets in service
- capital assets held for future use
- capital assets held for resale
- research, development and preliminary engineering
- deferred projects
- projects with budgeted costs less than $50,000
- projects which are expected to be completed in less than three (3) months

2.8 Contribution In Aid of Construction

Source of

Consists of contributions or grants in cash, service or property from governments or government agencies, corporations, individuals and others for contributions in aid of construction and other purposes.

Refundable Contribution

Customers' Advance for Construction, G/L Account 25500 is reviewed at least annually by Finance, and any balance remaining by customer according to agreement or rule, shall be reclassified to contribution in aid of construction.

Accounted for

The gross costs of the capital asset constructed is charged to the appropriate Gas Plant in Service account with a contra 21101 account to offset, the contribution in aid of construction.

From Billable Work

Recoverable costs, from billable work capitalized as capital additions, are accounted for as a contribution in aid of construction.

2.8 Classification of Capital Expenditures

Reason for

Certain types of expenditures warrants explanations in respect of capitalization policy, because of their function purpose and unique characteristics they are:

- computer software
- land
- leased property
- leasehold improvements
- pipe and station classification
- pipeline – relocations and replacements
- preliminary project development costs
- spare parts
- training, displays and documentation materials
- intangible plant
- NGV facilities
- gas plant held for future use
- gas plant not in rate base
- deferred projects
- abandoned projects
- property taxes

Each of these are described below.

2.8.1 Computer Software

Purchased

Purchased computer software is capitalized according to the minimum capitalization level; See Capitalization Policy, Minimum Capitalization Level, Section 2.2.

In-House

The cost of in-house developed software will be considered for capitalization in accordance with the Capitalization Policy, Minimum Capitalization Level, Section 2.2.

- or based on an assessment of the individual project, it will include the cost of designing programs and implementing the system

Note: 1. Implementation costs will normally include acceptance testing and the development of training materials.

2. Additionally, data conversion and user training costs will also be included

as an implementation cost in developing major systems which significantly impact the company's operating and/or business practices and procedures, e.g. projects such as IBIS (SAP).

Enhancements

Subsequent enhancements are capitalized if:

- it meets the Improvement and Additions Criteria referred to under Section 2.3.2, and
- it meets the same minimum capitalization level set for in-house developed software

2.8.2 Land

Temporary Accounts

The cost of land is capitalized to plant and classified in one of the following accounts until it is placed in service:

- gas plant held for future use – when purchased with no immediate use
- work-in-progress – when purchased directly for, or transferred in from gas plant held

Cost Excluded

The costs of clearing, grading, leveling and surveying both before and after the construction are to be included in the cost of constructing the plant facilities and, therefore, are not to be included in the cost of the land.

Not-In-Service, Resale

Land that is not-in-service or removed from in-service for resale, is classified as Gas Plant Not In Rate Base; until sold.

2.8.3 Leased Property

Capitalization Criteria

Leases are capitalized if the terms of the lease transfer substantially all of the benefits and risks of ownership related to the property from the lessor to Terasen Gas (lessee). There are no restrictions on the term of capitalized leases.

Transfer of Ownership

Ownership passes to Terasen Gas at the inception of the lease provided one or more of the following conditions are present:

Time of Transfer

- the terms of the lease provide that ownership of the leased property passes to Terasen Gas by the end of the lease term, or the lease provides for a bargain purchase option minimum $1,000 per PRU

Receive Economic Benefits

- the lease term is of such a duration that Terasen Gas will receive substantially all the economic benefits expected to be derived from the use of the leased property over its useful life (when lease term exceeds 75% of useful life)

Returns Assured

- the lessor would be assured of recovering the investment in the leased property and of earning a return on the investment as a result of the lease agreement

Leases Less Than $10,000

- for leases with payments over the term totaling less than $10,000 and where the asset is acquired at the end of the agreement or on buyout, the asset is recorded at the time of transfer of title to Terasen Gas

Financial Information System (FIS) Lease,
Vehicle Lease Agreement (VLA)

- in compliance with BCUC's Decision, August 5, 1992, these leases are not regarded as capital leases; and for "Legal" Balance Sheet purposes are recorded in Plant not in Rate Base by recording the net changes in the value of the leases between capital assets, accumulated depreciation, and the lease liability accounts
- for financial and budget purposes, the leases are accounted for in the O&M accounts
- costs incurred to enhance the FIS are capitalized in rate base, subject to the criteria referred to under Section 2.8.1

Proper Documentation

In all cases, documentation to substantiate ownership must be prepared and copies to Asset Accounting when ownership passes to Terasen Gas.

2.8.4 Leasehold Improvements

Criteria

A leasehold improvement exists when Terasen Gas leases property and incurs costs to make the property suitable for its use; e.g. offices, warehouses.

Capitalized When

Leasehold improvements are capitalized to the extent that:

- they exceed the owner's allowance by $1,000; and
- they provide benefits to Terasen Gas; and
- the term of the lease is in excess of 12 months

Types of Expenditures

Leasehold improvements

- office renovations to walls, floors and ceilings
- items permanently affixed to the structure
- non-salvageable, e.g. communication cables

Amortized

Leasehold improvements are amortized over the life of the lease and retired from plant in service when the facility is vacated.

2.8.5 Pipe and Station Classification

Pipe Classification

Pipe is classified based on the pipe pressure.

Low Pressure (LP) – 1.2 to 14 kPa
Distribution Pressure (DP) – 15 to 700 kPa
Intermediate Pressure (IP) – 701 to 2,070 kPa
Transmission Pressure (TP) – 2,071 kPa and up

Station Classification

Station structures and related assets such as land, land rights and equipment are classified based on the station's outlet pressure.

See appendix C for detailed Asset Classification diagram.

2.8.6 Pipeline Relocations and Replacements

Pipe Relocations

Where a transmission or distribution pipeline of 20 or more continuous meters (65 feet) in length is relocated, that section changed is considered capital. The new line is a capital addition and charged to the appropriate capital asset. Where such a relocation results from action by a governmental authority, it will be accounted for in a similar manner.

Pipe Replacements

Where a transmission or distribution pipeline of 20 or more continuous meters (65 feet) in length is replaced for any reason, the original cost of the section removed is treated as a retirement and the total cost of opening and back filling the trench, as well as the installed cost of the new pipe is capitalized.

Pipe Removed

A retirement entry is to be made for pipeline removed and/or abandoned due to a relocation or replacement. The costs of removing the retired pipe from the trench are accounted for as removal/dismantling costs.

Service Line Pipe

The costs of extending or shortening an existing service line is defined as an alteration and therefore capitalized. No retirement entry is made until the entire service line is removed or abandoned. Note however, that changes in as-built length must be updated accordingly.

Reconditioning

The costs of reconditioning pipeline not removed are charged to maintenance.

2.8.7 Preliminary Project Development Costs

Definition and Purpose

Includes expenditures for preliminary surveys, plans, investigation, etc., made for the purpose of determining the feasibility of specific plant projects for gas services. These costs are to be specifically identified in the budget.

Significant Amounts

Preliminary project development costs in excess of $25,000 per project, will initially be charged to a specific Internal Order, approved in accordance with the appropriate authorization level. Each preliminary project is valid for 12 months from the date the Internal Order is issued.

Deferred Charges

Such costs will be deferred as Preliminary Survey and Investigation Charges (G/L 17210) where the results of the study determine that:

- technical feasibility is established
- future benefit is reasonably assured

These expenditures will remain in G/L 17210 until management approval to proceed or not is established.

Capitalization Determined

Once approval is granted to proceed with construction, the related preliminary charges accumulated in G/L 17210 will form part of the total CAR costs.

Expensed

A preliminary engineering project

- costing less than $25,000 is charged to current operations
- in excess to $25,000 for which no decision or result is obtained AFTER the allowable 12 months has expired, and for which no further costs will be incurred, the project will be reviewed by the Executive VP, Finance, who will determine the appropriate action to be taken

2.8.8 Spare Parts

Charged to Maintenance

Terasen Gas maintains an inventory of spare parts for its gas utility system. Spare parts generally are items comprised of less than a PRU and are, therefore, charged to inventory when purchased and expensed to maintenance when issued.

Types of Parts

Some spare parts however constitute Retirement PRUs such as:

- spare modules for gas meters
- spare telemetry circuit boards

and are capitalized upon purchase and depreciated over the same estimated service life as the PRU to which they are related.

Asset Accounting will determine whether a spare part constitutes a PRU. Requests should be addressed to Asset Accounting before purchasing the item.

2.8.9 Training, Display and Documentation Materials

Expensed

In compliance with the BCUC Decision of August 5, 1992, the costs incurred in acquiring or constructing Training, Display and Documentation Materials are expensed as incurred.

2.8.10 NGV Facilities

Currently the installed cost of NGV facilities are classified in three (3) categories:

- NGV Compressor Station	G/L 10076
- Cylinders' Leased	G/L 10087

NGV Compressor Station

Includes the packaged NGV fuel system installed at gas service stations for public use and, those installed in industrial sales customer's premises either for their own as well as public use.

Cylinders Leased

Includes the installed cost of cylinders leased to customers. This lease program was discontinued at December 31, 1991 and substituted by the NGV Customer Support Program in 1992.

Existing Customers are obligated to meet the 18-month lease agreement. Thereafter, it is their choice to either request a pay-out or return the cylinders to Terasen Gas. The cylinders are salvaged to inventory at market value for resale purposes.

The cost of refurbishing the cylinder is chargeable to the removal/dismantling Work Order, and the cost of reinspecting, testing and sealing is an ongoing O&M expense.

2.9 Intangible Assets

Non-Physical

Expenditure which results in the acquisition of intangible (non-physical) assets, are capitalized provided that:

Provision

- the privileges obtained runs in perpetuity or for a specified term of more than one year; or
- the expenditure is necessary or valuable in the operation of the company and
- the expenditure are in excess of $10,000

Type of Expenditures

Types of tangible asset expenditures are:

- franchises and consents paid to governmental authorities
- patents, licenses, rights and privileges

2.10 Gas Plant Held for Future Use

How to Maintain

The costs of acquiring or constructing plant items for future use are capitalized and classified as Gas Plant Held for Future Use. This account should be maintained in such detail as though the plant were in service.

Qualification Criteria

In order to qualify as Gas Plant Held for Future Use, the plant item must be:

- a physical asset, at a minimum of $500 each
- not in-service or part of unfinished construction
- intended for a specific potential use within 20 years

Held for Resale

If the project is terminated and no other future use is planned, the physical plant items are held for resale at the lower of cost or market value and the gain or loss included in the other income accounts.

2.11 Gas Plant Not in Rate Base

Established By Regulation

Terasen Gas may acquire or construct plant items which are useful and beneficial to the company, but, according to BCUC regulations, are not to be included in the rate base. Such costs are capitalized but classified as Gas Plan NOT in Rate Base.

Detailed Records

Terasen Gas will maintain subsidiary records in which Gas Plant Not in Rate Base is subdivided according to the plant facility to which it applied and to each group of plant accounts.

Type of Expenditures

Gas Plant Not in Rate Base may include the following Capital expenditures:

- BCUC disallowances on cost capitalized in prior years
- corporate art
- premium costs paid on acquisition of other gas utilities, whose plant costs are to be involved in rate base

Disposition

The disposition of Gas Plant Not in Rate Base is reflected on the Income Statement as other income or other income deductions. Refer to Chapter 4, Gas Plant In Service, Section 4.4.3, for policy on premium cost retirements.

2.12 Deferred Projects

Criteria

A project is deferred if the scheduled in-service or turn-on date has been delayed by management decisions and the work is halted for more than one year.

Write-Offs

Appropriate write-offs may be made at the time of the deferral and in subsequent reviews where:

- specific obsolescence of some costs is identified; or
- changes in technology or environmental considerations may progressively diminish the usefulness and degree of certainty of recovery

Treatment of Assets Retained

Assets retained at the site may have to be mothballed. Costs of mothballing and maintenance costs during the deferral period as well as demothballing costs are all charged against operations when incurred, since no betterment of the asset has occurred.

AFUDC

Allowance for Funds Used During Construction is discontinued if a project has been deferred. AFUDC continues to be charged to a project if:

- it has been delayed less than 2 years; and
- work has not been physically stopped for more than one year but just been “slowed down” or “stretched out”

Unfinished Construction

Deferred projects will be included in unfinished construction for statement purposes unless significant enough to warrant separate disclosure.

Reactivated

A deferred project will be reclassified as an active project when:

- construction activity resumes; or
- management commitment to proceed with the project is reinstated and engineering work resumes; and provided that,
- a re-evaluation of the estimated project costs is made, and if necessary, a revised <> is processed

2.13 Abandoned Projects

Written-Off

A capital project is considered abandoned when it is decided never to reactivate it again. The costs incurred to date, exclusive of AFUDC and physical assets remaining, are written-off as charges to operations, or if significant, to other income deductions.

Accounting For Physical Assets

Physical assets relating to abandoned projects are either:

- disposed of by resale
- returned to inventory
- transferred to other projects at market value, except where no market value exists in which case original costs will be used; or
- written-off if they have no alternative use or market value

2.14 Property Taxes

Paid on Assets

Terasen Gas pays property taxes, grants or percentage amount in lieu of general taxes on its assessable capital assets while they are in-service or held for future use.

Capitalized When

Taxes on capital assets under construction or on capital assets that are not yet ready for service are capitalized and charged to the appropriate work order or capital account.

Reporting Quantity Data

Operations managers will be responsible to report as required the quantive data by capital district for Recurring Plant to Financial Performance Accounting. This data is used to compute the assessable capital assets for property tax purposes.

Reporting Capital Data

Asset Accounting is responsible to accumulate and report capital additions and retirements of assessable capital assets to the Taxation department.

Appendix J

A.S. Cheung
28 Douglas Woods View SE
Calgary, AB Canada
T2Z 2A2

PST Registration #:

GST Registration #: 86738 9173 RT0001

Bill To:

BC Gas Utility Ltd.
1111 West Georgia Street
Vancouver BC V6E 4M4

Invoice #: 00000022
Date: 4/1/01
Page: 1

DATE	UNITS	NOTES	PRICE	AMOUNT
3/7/01	1	Meeting in Vancouver	$1,100.00	$1,100.00
3/22/01	43	IPC report	$130.00	$5,590.00

VENDOR ID 1013296
VOUCHER NO. 5100029467
BATCH NO.
5105629234

CODE	RATE	TAX	SALE AMOUNT
GST	7%	$468.30	$6,690.00

GST:	$468.30
PST:	$0.00
Total Amount:	$7,158.30
Amount Applied:	$0.00
Balance Due:	$7,158.30

Comment:

Terms: Net 30 after EOM

STIKEMAN ELLIOTT

Barristers & Solicitors
4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Canada T2P 5C5
Tel: (403) 266-9000 Fax: (403) 266-9034 www.stikeman.com

STATEMENT OF ACCOUNT

BC Gas Utility Ltd.
7th Floor, 1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4

May 28, 2001
File No. 051644.1007
Invoice No. 4125350

Attention: Director, Legal Services

G.S.T. NO. R121411136

RE: Inland Pacific Connector Open Season

FOR PROFESSIONAL SERVICES RENDERED during the period April 3, 2001 to May 24, 2001.

Date	Lawyer	Time	Description
Apr 06/01	CKY	0.50	Office conference with Mr. Grant.
Apr 06/01	BBG	0.50	Office conference with Mr. Yates.
Apr 08/01	BBG	0.50	Review documents from BC Gas applications to National Energy Board (NEB) and British Columbia Utilities Commission (BCUC) re Southern Crossing.
Apr 09/01	BBG	3.75	Research re Southern Crossing Pipeline; office conference with Mr. Yates.
Apr 10/01	BBG	5.75	Further review of documents re Southern Crossing Pipeline and open season terms; review Southern Crossing Pipeline contractual documents; prepare research binders; prepare list of issues for meeting with BC Gas.
Apr 11/01	CKY	3.00	Preparation for and meeting with BC Gas (Richards, Marston, Des Brisay).
Apr 11/01	DAH	6.50	Prepare for meeting, including review of open season procedures for pipelines; meet with BC Gas to discuss potential pipeline project and open season.

Date	Lawyer	Time	Description
Apr 11/01	BBG	7.25	Preparation for and meeting with Ms. Marston, Mr. Richards and Ms. Des Brisay; prepare list of issues to incorporate into open season procedures.
Apr 12/01	CKY	1.00	Office conference with Mr. Grant; voice messages to and from Mr. Richards.
Apr 12/01	BBG	6.25	Office conference with Mr. Yates; e-mail from and telephone conference with Mr. Richards; preparation of initial draft procedures for open season.
Apr 13/01	CKY	0.50	Office conference with Mr. Grant re open season; voice messages to and from Mr. Richards.
Apr 13/01	BBG	4.00	Further preparation of draft open season procedures; office conference with Mr. Yates.
Apr 14/01	DAH	1.50	Review and comment on draft open season documents.
Apr 15/01	BBG	1.50	Review and revise open season procedures.
Apr 16/01	CKY	1.50	Review open season draft documentation; telephone conference with Mr. Richards; voice message to Mr. Grant.
Apr 16/01	BBG	1.50	Further review and revision of open season procedures; e-mail to BC Gas; voice message from Mr. Yates.
Apr 17/01	BBG	8.75	Prepare schedules to open season procedures.
Apr 18/01	BBG	8.25	Further preparation of schedules for open season procedures; e-mail to BC Gas.
Apr 19/01	BBG	1.00	Further preparation of schedules to open season procedures.
Apr 20/01	BBG	2.00	Review correspondence re Westcoast open season; review Westcoast open season documents; further preparation of schedules to BC Gas open season documents.

Date	Lawyer	Time	Description
Apr 21/01	MHB	0.50	Review materials re Westcoast open season.
Apr 22/01	MHB	2.00	Review and provide comments re BC Gas open season documents; review e-mail received from Mr. Parnell re Westcoast open season and marketing documents re need for expanded capacity.
Apr 23/01	BBG	9.08	Further preparation of schedules to open season documents; revise open season procedures and schedules; telephone conference with Mr. Richards.
Apr 24/01	BBG	12.00	Review and revise open season documents; telephone conferences with Mr. Richards.
Apr 25/01	DAH	2.25	Review and comment on drafts of open season material.
Apr 25/01	BBG	10.50	Review revisions to open season procedures; Prepare for and participate in conference call with Mr. Richards, Ms. Marston and Ms. Des Brisay; revise open season procedures; e-mail to BC Gas; telephone conference with Ms. Des Brisay.
Apr 26/01	BBG	2.50	Revise revised open season procedures; e-mail to BC Gas; telephone conference with BC Gas credit department; revise schedules to open season procedures.
Apr 26/01	SLU	2.50	Review and comment on draft guarantee.
Apr 27/01	BBG	8.83	Review revise Schedules A, B and E to open season procedure; e-mail to BC Gas; review and revise form of guarantee and e-mail to BC Gas; telephone conference with Ms. Marston, Ms. Des Brisay and Mr. Richards; revise Firm Transportation Upstream Capacity Agreement and Firm Transportation Service Agreement; revise open season procedures.
Apr 27/01	SLU	0.58	Finalize comments on guarantee.

Date	Lawyer	Time	Description
Apr 28/01	BBG	8.75	Revise and revise open season procedures; e-mail and fax to Mr. Jespersen, Ms. Marston, Ms. Des Brisay and Mr. Richards; review and revise Firm Transportation Upstream Capacity Agreement; review and revise Firm Transportation Precedent Agreement.
Apr 29/01	DAH	1.25	Review and comment on redrafts of open season material.
Apr 29/01	BBG	3.50	Revise schedules to open season procedures; review fax from Ms. Marston; review e-mail from Ms. Des Brisay; e-mail and fax schedules to Mr. Richards, Ms. Des Brisay, Ms. Marston and Mr. Jespersen.
Apr 30/01	BBG	11.25	Revise open season procedures; revise Schedule A; telephone conference with Ms. Des Brisay; telephone conference with Ms. Marston; review fax from Ms. Marston and revise schedules; review fax from Ms. Des Brisay and revise documents; office conference with Ms. Buchinski; telephone conference with Ms. Des Brisay.
Apr 30/01	MHB	6.50	Revise and provide comments re open season documentation; office conference with Mr. Grant re open season procedures and documentation.
May 01/01	DAH	2.33	Review of new documents; office conference with Mr. Grant; review of other open season processes re handling of rate methodology and cost issues.
May 01/01	BBG	12.25	Review and revise open season procedures and schedules; e-mail to BC Gas; office conference with Mr. Holgate.
May 01/01	MHB	3.00	Review and provide comments re open season procedure documents.

Date	Lawyer	Time	Description
May 02/01	BBG	5.75	Review and revise open season procedures and schedules; review e-mails from Ms. Des Brisay; e-mail documents to BC Gas; telephone conferences with Ms. Des Brisay; review summary; telephone call from BC Gas re open season documents.
May 03/01	DAH	0.50	Preliminary review of new documents.
May 03/01	BBG	11.00	Telephone conference with Ms. Des Brisay; revise open season documents; e-mails to BC Gas.
May 03/01	JAJ	0.17	Conduct corporate search re BC Gas Inc.
May 04/01	BBG	9.08	Review e-mails from Ms. Des Brisay; telephone conferences with Ms. Des Brisay; revise open season documents; e-mail open season documents to BC Gas; further review and revision of open season documents; telephone conferences with Ms. Des Brisay.
May 04/01	MJS	4.50	Review guarantee of firm transportation obligations; prepare revisions to guarantee for Mr. Grant.
May 06/01	DAH	1.00	Further review of documents provided by Mr. Grant.
May 07/01	BBG	1.00	Revise consolidated open season procedures; review and revise form of guarantee.
May 10/01	BBG	1.00	Review and revise form of guarantee.
May 11/01	BBG	1.00	Further review and revision of guarantee; e-mail to Ms. Des Brisay.
May 13/01	MHB	1.33	Review and provide comments on draft guarantee.

Lawyer	Hourly Rate	Hours Billed	Total
C. Kemm Yates	$425.00	6.50	$ 2,762.50
David A. Holgate	$375.00	15.33	5,748.75
Marie H. Buchinski	$200.00	13.33	2,666.00
Bradley B. Grant	$185.00	158.49	29,320.65
Michael J. Styczen	$175.00	4.50	787.50
Stephanie L. Uhlich	$165.00	3.08	508.20
Jennifer Jones	$ 85.00	0.17	14.45

	FEES	GST	TOTAL
OUR FEE	$ 41,808.05		
OTHER CHARGES			
Photocopies — Internal	89.10		
Telecopier	6.00		
Telephone	25.89		41,929.04
PLUS 7% GST		$2,935.03	2,935.03
TOTAL FEES and OTHER CHARGES			$44,864.07
DISBURSEMENTS			
Subject to GST			
Corporate Registry Search	3.00		
Deliveries	16.23		
			19.23
		1.34	1.34
TOTAL GST PAYABLE		$2,936.37	
THIS IS OUR ACCOUNT			$44,884.64

44734.61 (P4)
150.03 (P3)

The services indicated above have been rendered and this account truly shows the nature of the services, the time spent, the fees claimed, disbursements made and all money received in this matter.

APPROVED
CHARGE TO ACCOUNT W-00339-1.A.1.C

CC: C. DES BRISAY
J. POLLOCK

RECEIVED
JG 07 2001
CCOUNTS PAYABLE

VENDOR ID 1010371
VOUCHER NO. 19-1,74
NO.

CKY\176887

STIKEMAN ELLIOTT

Per: ______________________
C. KEMM YATES

Please quote file number 051644.1007 when making payment. Accounts are due when rendered. Interest at the rate of **5** percent per annum will be charged for amounts unpaid 30 days or more.

Appendix K

WESTLAND
RESOURCE GROUP INC.

JUN 12 2001

File

Invoice

1863 Oak Bay Avenue, Victoria, British Columbia, Canada V8R 1C6 Phone 250-592-8500 Fax 250-592-1633

TO:	BC Gas Utility Ltd. 2nd Floor - 16705 Fraser Highway Surrey, BC V3S 2X7	**WRG INVOICE #**	**01-001-3**
		BC Gas PO Number 4500009164	
ATTENTION:	**Mr. Bill Manery, P.Eng.**	**DATE:**	June 6, 2001
FROM:	**Mark Walmsley**	**BN # 88619 5080**	
RE:	**Inland-Pacific Connector Project** **Stage 1 Enviromental Impact Assessment** **May 1, 2001 to May 31, 2001**		

FEES NAME	HOURS	$/HOUR	FEES	
Mark Walmsley, Project Coordinator	89.00 ✓	90	$	8,010.00
Wayne Biggs, Manager - Biological & Physical Sciences	25.00 ✓	90	$	2,250.00
David Harper, Manager - Land Use	154.50 ✓	90	$	13,905.00
Ian Robertson, Senior Wildlife Biologist	45.00 ✓	90	$	4,050.00
John Cooper, Senior Wildlife Biologist	57.00 ✓	75	$	4,275.00
John Millar, Senior Fisheries Biologist	55.00 ✓	90	$	4,950.00
Lorna Duncan, Fisheries Biologist	58.00 ✓	80	$	4,640.00
Jennifer Robertson, Fisheries Biologist	30.00 ✓	80	$	2,400.00
Tracy Ford, Fisheries Biologist	42.00 ✓	80	$	3,360.00
Jeff Wright, Senior Fisheries Biologist	127.50 ✓	75	$	9,562.50
Chris Parks, Senior Fisheries Biologist	202.50 ✓	80	$	16,200.00
Jean Bussey, Principal Archaeologist	69.00 ✓	90	$	6,210.00
Gabriella Prager, Senior Archaeologist	69.00 ✓	75	$	5,175.00
Dave Schaepe, Senior Archaeologist	56.00 ✓	75	$	4,200.00
Chris Cena, Fisheries Biologist	187.50 ✓	75	$	14,062.50
Eleanor Setton, Land Use Planner	29.00 ✓	75	$	2,175.00
Joe Boyd, GIS Analyst	92.00 ✓	75	$	6,900.00
Senior Technicians	187.00 ✓	60	$	11,220.00
Assistants	124.50 ✓	40	$	4,980.00
Susan Wangsness, Environmental Planner	64.50 ✓	45	$	2,902.50
Marsha Mallow, Accounting	41.50 ✓	40	$	1,660.00
Corrina Kerrigan, Administrative Assistant	82.50 ✓	35	$	2,887.50
		TOTAL FEES	$	135,975.00 ✓

Key Text	
S/E 10000 28198	
WBS/Order: as noted	Cost Element: 63101
Approved For Payment: [signature]	Date (YY/MM/DD): June 20/01
SAP Document No.: 5156377	Vendor No.
Date Posted/Parked: JUN 26 2001	Entered By: [initials]

VENDOR ID	1009113
VOUCHER NO.	5/05630271
BATCH NO.	5/0030476

JUN 26 2001

RECEIVED

Invoice No. 01-001-3 ..... continued

JUN 12 2001

WESTLAND
RESOURCE GROUP INC.

Invoice

1863 Oak Bay Avenue, Victoria, British Columbia, Canada V8R 1C6 Phone 250-592-8500 Fax 250-592-1633

RECEIPTED EXPENSES (See attached sheets)		AMOUNT
Harper Expense Record No. DEH01-18	May 3+5 food	$ 182.27
Harper Expense Record No. DEH01-18A	May. 13+15 food	$ 1
Harper Expense Record No. DEH01-18B	May 4 acc	$ 8
Harper Expense Record No. DEH01-20	May 14 + 15 accom + transport	$ 347
Harper Expense Record No. DEH01-22	May 23	$
Manning, Cooper and Associates #MCA 01-111	May 14 - 19	$
Parks Expense Record No. May/01	May 9 - June 3	$
Points West Heritage Consulting #WRG01-203 Revised	May 5 - May 28	$ 1,254.45
		$ 3,358.85
		$ 113.56
	May 14 - 10	$ 1,278.43
Walmsley Expense Record No. MEW01-20	May 23	$
Walmsley Expense Record No. MEW01-21	May 30 A £	$
		$

expenses

	UNITS	UNIT COST	AMOUNT
	42	$ 86.70	$ 3,641.40
	27	$ 10.00	$ 270.00
	9	$ 10.00	$ 90.00
	11	$ 25.00	$ 275.00
	19	$ 75.00	$ 1,425.00
	15	$ 25.00	$ 375.00
	19	$ 25.00	$ 475.00
	151	$ 0.39	$ 58.89
	5,762	$ 0.59	$ 3,399.58
	49	$ 66.30	$ 3,248.70
	61	$ 8.00	$ 488.00
	61	$ 10.00	$ 610.00
I	63	$ 17.70	$ 1,115.10
F	21	$ 0.50	$ 10.50
P	2,425	$ 2.00	$ 4,850.00
Report Production (with binders)	3	$ 15.00	$
Truck, 4 x 4 (per day)	9 58 28	$ 91.80	$
		TOTAL NON-RECEIPTED EXPENSES	$

TOTAL FEES & EXPENSES	$ 180,837.15
GST @ 7%	$ 12,658.60
	$ 193,495.75

BC Gas - Inland-Pacific Connector Pipeline Project
Cost Control Sheet for Invoice No. 01-001-3 dated June 6, 2001

			1.A.2.A	1.A.2.A	1.A.2.A	1.A.2.B	1.A.2.B	1.A.2.C	1.A.2.A
Cost Element		**Deliverable**	Administration and Program Management	Route Assessment and Selection	Environmental Assessment of Selected Route and Access Roads	Preparation of PAC Application	Preparation of CEAA Application	Involvement with Consultation Program (Public and First Nations)	Environmental Assessment for Compressor Stations
Westland (hrs)		MW	40	10				10	29
		WB			25				
		DH		70	64.5			20	
		JB		70	22				
		MM	41.5						
		CK	82.5						
		CP			202.5				
		CC			187.5				
		LA							
		ES			29				
		SW		64.5					
		Sr. Tech.							
		Tech.							
		Assist.							
Contractors/Subcontractors (hrs)	Archaeology	JB			69				
		DS			56				
		GP			69				
		SC							
		Assist.							
		Tech.							
	Aquatic Resources/ Fisheries	JM			55				
		LD			58				
		JW			127.5				
		JR			30				
		TF			42				
		Sr. Tech.			51				
		Tech.							
		Assist.			123.5				
	Terrain	DM							
		Sr. Tech.							
		Tech.							
		Assist.							
	Agriculture	HL							
		Sr. Tech.							
		Tech.							
		Assist.							
	Water Resources	JR							
		Sr. Tech.							
		Tech.							
		Assist.							
	Wildlife	IR		45					
		JC		57					
		MS							
		MK							
		Sr. Tech.			136				
		Tech.							
		Assist.			1				
	First Nations	Aboriginal Interest Studies $			# 177,639 to 1.A.2.A				

Subtotals	8,148	23,678	98,840	0	0	2,700	2,610
Disbursements	2,200	5,435	35,028			500	1,700
Total Cost This Invoice	10,348	29,113	133,868	0	0	less 3,200	4,310
Cost Previous Period	22,256	67,833	17,807	0	0	0	0
Total Cost To-Date	32,604	96,946	151,675	0	0	3,200	4,310
Approved Budget to July 31/01 as of May 24/01 ($000's) 762,500	50,000	100,000	512,500	10,000	0	20,000	10,000
Budget Remaining ($000's)	17,397	3,055	360,825	10,000	0	16,800	5,690

IPC

WESTLAND
RESOURCE GROUP INC.

Invoice

1863 Oak Bay Avenue, Victoria, British Columbia, Canada V8R 1C6 Phone 250-592-8500 Fax 250-592-1633

TO:	BC Gas Utility Ltd. 2nd Floor - 16705 Fraser Highway Surrey, BC V3S 2X7	WRG INVOICE # 9	01-001-9
		BC Gas PO Number 4500009164	
ATTENTION:	Mr. Bill Manery, P.Eng.	DATE:	December 7, 2001
FROM:	Mark Walmsley	BN # 88619 5080	
RE:	Inland-Pacific Connector Project Stage 1 Environmental Impact Assessment November 1, 2001 to November 30, 2001		

FEES NAME	HOURS	$/HOUR	FEES
Mark Walmsley, Project Coordinator	152.00	90	$ 13,680.00
Wayne Biggs, Manager - Biological & Physical Sciences	77.00	90	$ 6,930.00
David Harper, Manager - Land Use	93.50	90	$ 8,415.00
Jean Bussey, Principal Archaeologist	44.00	90	$ 3,960.00
Gabriella Prager, Senior Archaeologist	52.00	75	$ 3,900.00
Chris Parks, Senior Fisheries Biologist	94.00	80	$ 7,520.00
Joe Boyd, GIS Analyst	62.00	75	$ 4,650.00
Sarah Maxwell, Planning Assistant	29.50	45	$ 1,327.50
Marsha Mallow, Accounting	84.00	40	$ 3,360.00
		TOTAL FEES	$ 53,742.50

RECEIPTED EXPENSES (See attached sheets)		AMOUNT
Harper Expense Record No. DEH01-49	Nov ~~16~~, 22, 23	$ 404.28
Harper Expense Record No. DEH01-49B	Oct 26, Nov 22	$ 9.85
Morrow Environmental Consultants Inc. #41525	Aug - Oct 16 - Oct Expenses	$ 1,568.36
Parks Expense Record No. CP01-16	Nov 22	$ 79.00
Points West Heritage Consulting Ltd. #WRG01-206	Nov 29-30	$ 490.18
Walmsley Expense Record No. MEW01-50	Nov 1	$ 154.56
Walmsley Expense Record No. MEW01-51	Nov 13 & 14	$ 216.61
Walmsley Expense Record No. MEW01-53	Nov 22 & 23	$ 569.48
Walmsley Expense Record No. MEW01-55	Nov 27 30	$ 285.49
Walmsley Expense Record No. MEW01-55A	Nov 30	$ 5.61
Third Party Receipted Expenses		$ 584.28
	TOTAL RECEIPTED EXPENSES	$ 4,367.70

Key Text: 01-001-9 - Nov 1-30 - Time + Mat

WBS/Order: S00 [illegible]	Cost Element: 63101
Approved For Payment: [signature]	Date (YY/MM/DD)
SAP Document No.: 5E1/34507	Vendor No.: 1009113
Date Posted/Parked: ENTERED DEC 18 2001	Entered By: [initials]

RECEIVED
DEC 12 2001
File IPC Project

" Inv 01-001-9 Nov 1-30/01 Time & Exp."

DEC 19 2001

DEC 19 2001

Invoice No. 01-001-9 .... continued

WESTLAND
RESOURCE GROUP INC.

Invoice

1863 Oak Bay Avenue, Victoria, British Columbia, Canada V8R 1C6 Phone 250-592-8500 Fax 250-592-1633

NON-RECEIPTED EXPENSES (See attached sheet)	UNITS	UNIT COST	AMOUNT
Camera, Digital (per day)	2	$ 10.00	$ 20.00
Kilometres, regular vehicle (per day)	666	$ 0.39	$ 259.74
Kilometres, 4 x 4 vehicle (per km)	333	$ 0.59	$ 196.47
Breakfast (per day)	9	$ 8.00	$ 72.00
Lunch (per day)	9	$ 10.00	$ 90.00
Dinner (per day)	6	$ 17.70	$ 106.20
Plotting - Bond (per sq.ft.)	284	$ 2.00	$ 568.00
Report Production (Draft PAC)	10	$ 100.00	$ 1,000.00
Truck, 4 x 4 (per day)	2	$ 91.80	$ 183.60
		TOTAL NON-RECEIPTED EXPENSES	$ 2,496.01
		TOTAL FEES & EXPENSES	$ 60,606.21
		GST @ 7%	$ 4,242.43
		TOTAL INVOICE	$ 64,848.64

coding { 339.1.A.2.A $10,388
339.1.A2.B $50,219

P3

Allocated $60,607.60
Bill 694.

BC Gas - Inland-Pacific Connector Pipeline Project
Cost Control Sheet for Invoice No. 01-001-9 dated December 7, 2001

Cost Element			Deliverable: Administration and ~~Program~~ Management W.335.1A2A	Route Assessment and Selection 1A2A	Environmental Assessment of Selected Route and Access Roads 1A2A	Preparation of PAC ~~Application~~ 1A2B	Preparation of CEAA Application 1A2B.	Involvement with Consultation Program (Public and First Nations) 1A2C	Environmental Assessment for Compressor Stations 1A2A
Westland (hrs)		MW	50			102			
		WB				77			
		DH				93.5			
		JB				62			
		MM	84						
		CP				94			
		CC							
		MA							
		ES							
		SM	29.5						
		Sr. Tech.							
		Tech.							
		Assist.							
Contractors/Subcontractors (hrs)	Archaeology	JB				44			
		DS							
		GP				52			
		PB							
		SC							
		BG							
		LR							
		Assist.							
		Tech.							
	Aquatic Resources/ Fisheries	JM							
		LD							
		JW							
		LA							
		JR							
		TF							
		PE							
		Sr. Tech.							
		Tech.							
		Assist.							
	Air Quality	RC							
		RH							
		Sr.Tech.							
	Contaminated Sites	CW							
		EN							
		Sr.Tech.							
		Tech.							
		Assist.							
	Terrain	DM							
		Sr. Tech.							
		Tech.							
		Assist.							
	Agriculture	HL							
		Sr. Tech.							
		Tech.							
		Assist.							
	Socio-Economic	JS							
		Sr. Tech.							
		Tech.							
		Assist.							
	Wildlife	IR							
		JC							
		MS							
		MK							
		Sr. Tech.							
		Tech.							
		Assist.							
	First Nations	Sto:lo (Env. Res. Assist.) $							

Subtotals	9,188	0	0	44,555	0	0	0
Disbursements	1,200			5,664			
Total Cost This Invoice $ 60,607.00	10,388	✓ 0	0	50,219	✓ 0	0	0
Cost Previous Period 861,134 ~~851,134.00~~	72,484	144,026	619,041	6,828	0	11,180 ~~1,180~~	7,575
Total Cost To-Date 921,741.	82,872	144,026	619,041	57,047	0	11,180 ~~1,180~~	7,575
Approved Budget to July 31/01 as of May 24/01 ($000's) 782,500	50,000	100,000	512,500	10,000	0	20,000	10,000
Budget Remaining ($000's)	-32,872	-44,026	-106,541	-47,047	0	18,820	2,425

RECEIVED

MAR - 8 2002

File ~~IPC Project~~

WESTLAND
RESOURCE GROUP INC.

Invoice

1863 Oak Bay Avenue, Victoria, British Columbia, Canada V8R 1C6 Phone 250-592-8500 Fax 250-592-1633

TO:	BC Gas Utility Ltd. 2nd Floor - 16705 Fraser Highway Surrey, BC V3S 2X7	**WRG INVOICE # 9**	**01-001-12**
		BC Gas PO Number 4500009164	
ATTENTION	**Mr. Bill Manery, P.Eng.**	**DATE:**	March 4, 2002
FROM	**Mark Walmsley**	**BN # 88619 5080**	
RE	**Inland-Pacific Connector Project** **Stage 1 Environmental Impact Assessment** **February 1, 2002 to February 28, 2002**		

FEES NAME	HOURS	$/HOUR	FEES
Mark Walmsley, Project Coordinator	111.00	90	$ 9,990.00
Wayne Biggs, Manager - Biological & Physical Sciences	44.00	90	$ 3,960.00
David Harper, Manager - Land Use	72.50	90	$ 6,525.00
Chris Parks, Senior Fisheries Biologist	124.00	80	$ 9,920.00
Mike Akey, Fisheries Biologist	82.00	60	$ 4,920.00
Joe Boyd, GIS Analyst	77.50	75	$ 5,812.50
Sarah Maxwell, Planning Assistant	22.00	45	$ 990.00
Marsha Mallow, Accounting	28.25	40	$ 1,130.00

NAME	FEES
Sto:lo Nation (Environmental Research Assistant) no receipt received from them	$ 8,000.00
TOTAL FEES	**51,247.50**

RECEIPTED EXPENSES (See attached sheets)		AMOUNT
Akey Expense Record No. MA02-01	Feb 18 & 24	$ 16.00
Harper Expense Record No. DEH02-08	~~Feb 18-19~~ Jan 22, Feb 4-12	$ 454.61
Harper Expense Record No. DEH02-09	Feb 18-19	$ 742.09
Harper Expense Record No. DEH02-09B	Feb 18-19	$ 13.67
Parks Expense Record No. CP02-01	Feb 8-28	$ 155.26
Walmsley Expense Record No. MEW02-01	Feb 1	$ 192.33
Walmsley Expense Record No. MEW02-01A	Feb 1	$ 5.55
Walmsley Expense Record No. MEW02-04	Feb 12-14	1,403.15
Walmsley Expense Record No. MEW02-05	Feb 18-20	$ 1,062.31
Walmsley Expense Record No. MEW02-06	Feb 25	$ 215.39
Walmsley Expense Record No. MEW02-06A	Feb 25	$ 4.67
Third Party Receipted Expenses		525.71
TOTAL RECEIPTED EXPENSES		**4,790.74**

1A2A

IPC

RECEIVED
MAR - 8 2002
File
IPC Project

Invoice 01-001-12 .... continued

WESTLAND
RESOURCE GROUP INC.

Invoice

1863 Oak Bay Avenue, Victoria, British Columbia, Canada V8R 1C6 Phone 250-592-8500 Fax 250-592-1633

NON-RECEIPTED EXPENSES (See attached sheet)	UNITS	UNIT COST	AMOUNT
Kilometres, regular vehicle (per day)	412	$ 0.39	$ 160.68 ✓
Kilometres, 4 x 4 vehicle (per km)	820	$ 0.59	$ 483.80 ✓
Breakfast (per day)	15	$ 8.00	120.00 ✓
Lunch (per day)	19	$ 10.00	190.00 ✓
Dinner (per day)	18	$ 17.70	318.60 ✓
Living-Out Allowance (accommodation only)(per day)	12	$ 66.30	795.60 ✓
Computer, Portable (per day)	7	$ 10.00	70.00
Digital Camera (per day)	7	$ 10.00	
Field Kit - Sampling Gear (per day)	7	$ 50.00	
GPS Unit (per day)	5	$ 25.00	
Plotting - Bond (per sq.ft.)	1,281	$ 2.00	
Photocopies @ .10/copy	445	$ 0.10	
Truck, 4 x 4 (per day)	7	$ 91.80	
		TOTAL NON-RECEIPTED EXPENSES	

TOTAL FEES & EXPENSES	$	61,971.02
GST @ 7%	$	4,337.97
TOTAL INVOICE		66,308.99 ✓ P3

Receipt : 4790.74
Non-Receipt 5932.78
10,723.52

Southern Crossing Pipeline Project
Vendor No.
Document No.
Posting Date
User I.D.:

Key Text 01-001-12 - Feb 1-28 - Time & Expenses	
WBS/Order ~~See attached~~	Cost Element 63101
Approved For Payment [signature]	Date (YY/MM/DD) Mar 2/02
SAP Document No. 1136592	Vendor No. 8/2482
Date Posted/Parked Mar 25/02	Entered By [signature]

Line -10 ~~18~~ 18,463.02

VENDOR ID	100943
VOUCHER NO.	
BATCH NO.	

1A2A 3273.02
(22,920-8000) = 14,920
~~18,463.02~~
1A2B 35,808. Line 1-20
1A2C 8000 Line 1-30
61,971.00

J

BC Gas - Inland-Pacific Connector Pipeline Project
Cost Control Sheet for Invoice No. 01-001-12 dated March 4, 2002

Cost Element			Deliverable	Administration and Program Management 1A2B	Route Assessment and Selection 1A2B	Environmental Assessment of Selected Route and Access Roads 1A2B	Preparation of PAC Application 1A2B	Preparation of CEAA Application 1A2B	Involvement with Consultation Program (Public and First Nations) 1A2C	Environmental Assessment for Compressor Stations 1A2A
Westland (hrs)		MW		21			90			
		WB					44			
		DH					72.5			
		JB					77.5			
		MM		28.25						
		CP				100	24			
		CC								
		MA				82				
		ES								
		SM					22			
		Sr. Tech.								
		Tech.								
		Assist.								
Contractors/Subcontractors (hrs)	Archaeology		JB							
			DS							
			GP							
			PB							
			SC							
			BG							
			LR							
			Assist.							
			Tech.							
	Aquatic Resources/ Fisheries		JM							
			LD							
			JW							
			LA							
			JR							
			TF							
			PE							
			Sr. Tech.							
			Tech.							
			Assist.							
	Air Quality		RC							
			RH							
			Sr.Tech.							
	Contaminated Sites		CW							
			EN							
			Sr.Tech.							
			Tech.							
			Assist.							
	Terrain		DM							
			Sr. Tech.							
			Tech.							
			Assist.							
	Agriculture		HL							
			Sr. Tech.							
			Tech.							
			Assist.							
	Socio-Economic		JS							
			GP							
			Sr. Tech.							
			Tech.							
			Assist.							
	Wildlife		IR							
			JC							
			MS							
			MK							
			Sr. Tech.							
			Tech.							
			Assist.			Sh be 1A2B	As discussed c B.M.			
	First Nations	Sto:lo (Env. Res. Assist.)	$	1A2B		1A2B 8000	1A2B		#8000 to 1.A.2.C	
Subtotals			51,248	3,020	0	20,920	27,308	0	0	0
Disbursements			10,723	223	0	2,000	8,500	0	0	0
Total Cost This Invoice			$61,971	3,243	0	22,920	35,808	0	0	0
Cost Previous Period				88,853	144,026	619,041	103,427	0	1,180	7,575
Total Cost To-Date				92,096	144,026	641,961	139,235	0	1,180	7,575
Approved Budget to July 31/01 as of May 24/01 ($000's)				50,000	100,000	512,500	10,000	0	20,000	10,000
Budget Remaining ($000's)				-42,096	-44,026	-129,461	-129,235	0	18,820	2,425

Appendix L

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-124-00

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Applications by BC Gas Utility Ltd.
for Approval of Rate Changes effective January 1, 2001

BEFORE: P. Ostergaard, Chair)
B.L. Clemenhagen, Commissioner) December 20, 2000
K.L. Hall, Commissioner)
N.F. Nicholls, Commissioner)

O R D E R

WHEREAS:

A. The Commission, by Order No. G-85-97, approved the terms of the BC Gas Utility Ltd. ("BC Gas") July 4, 1997 Settlement Agreement, as revised by its Consolidated Settlement Document, setting up a rate adjustment mechanism for a three-year test period beginning January 1, 1998; and

B. Commission Order No. G-48-00 extended the 1998-2000 Performance Based Rate Settlement to determine BC Gas' Revenue Requirements for 2001; and

C. On October 31, 2000, BC Gas filed its Revised Target Costs and Revenues for 2001 in accordance with the Settlement Agreement, projecting 2000 results for the incentive mechanisms (Capital, Demand-Side Management, and Earnings Sharing) and forecasts for 2001 to be included in 2001 rates. BC Gas responded to an Information Request from Commission staff on November 20, 2000; and

D. An Annual Review was held on November 21, 2000 in Vancouver, B.C., pursuant to Order No. G-90-00; and

E. On December 6, 2000, BC Gas filed updated Revised Targets for its 2001 Revenue Requirements responding to issues raised at the Annual Review and incorporating a projected 9.50 percent return on equity for BC Gas for the calendar year 2001 (the "Revenue Requirements Application"). The updated financial schedules showed the impact on return on rate base of amortizing the Gas Cost Reconciliation Account ("GCRA") balance over the period from January 1, 2001 to October 31, 2002, resulting in a revenue deficiency of $28.7 million, equivalent to a 1.79 percent increase in total revenue, effective January 1, 2001; and

F. Intervenors and participants in the Annual Review had until December 11, 2000 to make submissions on the material, after which time the Commission would make its decision on the Revenue Requirements Application. The British Columbia Public Interest Advocacy Centre and Ilse Leis were the only parties to make submissions, and BC Gas responded to the submissions on December 14, 2000; and

G. On December 19, 2000, BC Gas filed additional material for Commission consideration, and requested approval of a further $3.1 million reduction in forecast delivery margin revenue from industrial customers; and

H. Commission Letter No. L-61-00 approved a return on common equity of 9.25 percent for 2001 for a low risk benchmark utility; and

I. On December 6, 2000, BC Gas applied for approval to flow through gas purchase cost changes for the 2001 calendar year under its approved gas supply portfolio for the Lower Mainland, Inland and Columbia Divisions (the "Cost of Gas Application"). The Cost of Gas Application requested approval of rates to recover BC Gas' projected gas costs based on November 30, 2000 forward gas prices for 2001 that averaged US$6.45/MMBtu at Sumas and a currency exchange rate of US$0.667/$Cdn.; and

J. In the Revenue Requirements Application and the Cost of Gas Application, BC Gas projected the GCRA to have a debit balance (amount to be recovered) of $160 million to the end of 2000 and requested approval to recover this amount in rates over the period January 1, 2001 through October 31, 2002; and

K. The rates resulting from the December 6, 2000 revenue requirement filing, plus the requested gas cost and GCRA recovery increases, resulted in a 30 percent total increase in typical residential annual bills, and 30 to 41 percent increases to other rate classes; and

L. On December 12, 2000, BC Gas provided information showing that extending recovery of the GCRA balance over three years would reduce the bill increase for a typical residential customer to 27 percent; and

M. The Commission recognizes that there is considerable uncertainty with respect to forecasting gas prices for 2001. Differences between the revenue that is generated by the gas commodity portion of rates and the actual cost of gas will accumulate in the GCRA; and

N. The Commission has reviewed the submissions and is satisfied that approval of the delivery rate changes in the Revenue Requirements Application, adjusted for a 9.25 percent return on equity, and the gas cost changes in the Cost of Gas Application, with a 3-year recovery of the GCRA debit balance, is necessary and in the public interest.

NOW THEREFORE the Commission orders as follows:

1. Changes to BC Gas' Gas Tariff Rate Schedules, to reflect the following rate changes, are approved effective January 1, 2001, for the Lower Mainland, Inland and Columbia service areas:

   - Basic Charges, Delivery Charges and Riders, excluding the GCRA Rider, generally as calculated in the December 6, 2000 Revenue Requirements Application, with adjustments for a 9.25 percent return on equity and three-year amortization of the GCRA balance;

   - Gas Cost Recovery Charges as set out in the December 6, 2000 Cost of Gas Application

   - Gas Cost Reconciliation Account Riders calculated so as to recover in 2001 one-third of the projected GCRA debit balance to the end of 2000.

2. A Core Market Administration Costs budget of $1,581,000 is approved for 2001.

3. BC Gas, by way of a Customer Notice, is to provide all customers with an explanation of the rate changes. BC Gas is to provide the Commission with a final draft customer notice for each Division prior to publication. BC Gas is also to provide the Commission with a detailed breakdown of the rate changes by each customer class rate schedule and service area, on a cost per gigajoule basis, and show the bill impacts for the typical annual consumption for each class.

4. The Commission will accept, subject to timely filing, amended Gas Tariff Rate Schedules in accordance with the terms of this Order.

5. BC Gas is directed to file by June 5, 2001, a report on actual gas prices and costs for the 2001 year to date compared to forecast, price expectations for the remainder of the year, impact on the GCRA balance, and any rate changes that are proposed. The report should also discuss the effect of current and proposed rates on sales.

DATED at the City of Vancouver, in the Province of British Columbia, this 28th day of December 2000.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-123-01

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

BC Gas Utility Ltd.
2002 Revenue Requirements Application

BEFORE: P. Ostergaard, Chair)
K.L. Hall, Commissioner) November 20, 2001

O R D E R

WHEREAS:

A. On August 24, 2001, BC Gas Utility Ltd. ("BC Gas") applied to the British Columbia Utilities Commission ("the Commission") for approval to increase rates for customers in the Lower Mainland, Inland and Columbia service areas effective January 1, 2002 ("the Application"), pursuant to Sections 58 and 61 of the Utilities Commission Act ("the Act"); and

B. The Application sought to recover increased revenue requirements associated with delivering natural gas. An increase of about 7 percent would apply to rates for transportation service and to the distribution portion (excluding the commodity cost of gas) of rates for customers to whom BC Gas supplies the natural gas commodity. Expressed on a burnertip basis (including the current commodity cost of gas) the increase being sought would be about 2 percent; and

C. The Commission, by Order No. G-98-01, held a Workshop and Pre-hearing Conference on September 25, 2001 to identify the issues and interests in a longer-term regulatory framework for BC Gas and to discuss procedural matters related to the Application. By Order No. G-103-01, the Commission established a regulatory timetable and scheduled a Negotiated Settlement Process for the BC Gas Application to commence on November 5, 2001; and

D. On November 1, 2001, BC Gas filed notice that it was withdrawing its Application due to a number of factors and identified the proposed treatment of certain revenue and cost items; and

E. By letter dated November 2, 2001, the Commission cancelled the negotiation sessions scheduled for November 5, 2001 and invited intervenor comments by November 9, 2001 on BC Gas' withdrawal of the Application; and

. . ./2

F. On November 8, 2001, BC Gas held an information meeting for the participants that explained the effect of the withdrawal and, on November 9, 2001, provided additional information regarding the effects of the withdrawal. On November 9, 2001, the Commission received intervenor submissions and on November 13, 2001 BC Gas provided comments on the intervenor submissions; and

G. The Commission has reviewed the submissions of BC Gas and the intervenors and finds that a withdrawal of the Application as proposed by BC Gas is in the public interest.

NOW THEREFORE pursuant to Section 58 of the Act, the Commission orders as follows:

1. The Commission approves the BC Gas withdrawal of its 2002 Revenue Requirements Application for the reasons provided in the Reasons for Decision attached as Appendix A to this Order.

2. BC Gas is directed to file its Revenue Requirements Application for 2003 by May 31, 2002, and to address in that application the matters that are raised in the attached Reasons for Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of November 2001.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Attachment

BC GAS UTILITY LTD.
2002 REVENUE REQUIREMENTS APPLICATION
NOTICE OF WITHDRAWAL

REASONS FOR DECISION

1.0 BACKGROUND

1.1 BC Gas 2002 Revenue Requirements Application

On August 24, 2001 BC Gas Utility Ltd. ("BC Gas", "the Utility") applied to the British Columbia Utilities Commission ("the Commission") for approval to increase rates for customers in the Lower Mainland, Inland and Columbia service areas, effective January 1, 2002 to recover increased revenue requirements of approximately $32 million associated with delivering natural gas (the "Application"). An increase of about 7 percent would apply to rates for transportation service and to the distribution portion (excluding the commodity cost of gas) of rates for customers to whom BC Gas supplies the natural gas commodity. Expressed on a burnertip basis (including the current commodity cost of gas) the increase being sought was about 2 percent.

The Application did not deal with the gas commodity cost component of BC Gas' rates, which may be adjusted quarterly by the Commission based on BC Gas' forecasts of its commodity costs and revenues for the following 12 months.

The Application requested that the Commission determine the 2002 rates by way of the Commission's Negotiated Settlement Process. The Application also requested that the Commission sponsor a workshop to identify the issues and interests relating to a comprehensive multi-year regulatory framework for BC Gas.

The Commission, by Order No. G-98-01, held a Workshop and Pre-hearing Conference on September 25, 2001. The participants to the Workshop and Pre-hearing Conference agreed to a review of the Application by way of a Negotiated Settlement Process to establish costs and revenues that could form the basis of longer-term incentive rates.

The Commission, by Order No. G-103-01, scheduled a Negotiated Settlement Process for the BC Gas Application to commence on November 5, 2001. The Order also established a timetable for the registration of intervenors and interested parties, and the issuance of information requests and replies.

On October 23, 2001, as part of the Commission's Negotiated Settlement Process, Commission staff met with the Commission to identify any issues of particular concern. By letter dated October 26, 2001, Commission staff informed the registered intervenors and BC Gas of the Commission's position that the establishment of base year utility costs and revenues be a first and discrete step in the development of a multi-year performance based rate ("PBR") setting agreement. The Commission expected BC Gas to use the results of the upcoming settlement negotiations or hearing determination for 2002, in filing a separate multi-year PBR application.

1.2 BC Gas Notice of Withdrawal

On November 1, 2001 BC Gas filed a notice that it was withdrawing its Application. BC Gas explained that the withdrawal of the Application was due to a number of factors including the recently announced acquisition of Centra Gas British Columbia Inc. ("Centra BC") and Centra Gas Whistler Inc. by BC Gas Inc.; queries from various parties regarding the intentions of BC Gas for Centra BC from a regulatory perspective and the implications of this transaction on the Application; the Commission's letter dated October 26, 2001; and the request of representatives of some customer groups for BC Gas to reconsider its revenue requirements. BC Gas included letters of support to its withdrawal from three registered intervenors. BC Gas stated that with the withdrawal of its Application, the negotiation sessions scheduled for November 5, 2001 were unnecessary and should be cancelled.

BC Gas clarified the effect of its withdrawal by identifying the proposed treatment of identified revenue and cost items. The utility stated that in all other respects BC Gas would operate with the revenues that are generated by the current base rates. The utility considered that there would be cost pressures for 2002 which BC Gas would absorb and equally any benefits arising in 2002 which enhance the BC Gas' return would be retained by the utility.

By letter dated November 2, 2001, the Commission cancelled the negotiation sessions scheduled for November 5, 2001 and invited the registered intervenors to provide the Commission with written comments by November 9, 2001 on the BC Gas withdrawal.

A number of intervenors informed the Commission, BC Gas and other intervenors that it appeared that BC Gas was proposing a conditional withdrawal of its Application. These intervenors stated that it was difficult to compare the impact of the conditional withdrawal with the Application's 7 percent rate increase.

BC Gas held an information meeting for the participants on November 8, 2001 and provided additional information that explained the effect of the withdrawal. By letter dated November 9, 2001, BC Gas filed a copy of the additional information with the Commission. On November 9, 2001 the Commission received intervenor submissions and on November 13, 2001 BC Gas provided comments on the submissions.

2.0 COMMISSION FINDINGS

The November 1, 2001 letter from BC Gas states that: "…it withdraws its 2002 Revenue Requirement Application filed August 24, 2001 with the Commission." However, the attachment to that letter identifies that BC Gas is "prepared to withdraw its Application" with nine specific consequences of the withdrawal. Others have viewed the BC Gas action as a proposed withdrawal with conditions or a settlement proposal. Irrespective of the terminology that may be applied to the BC Gas withdrawal or application to withdraw with conditions, the Commission agrees with the views expressed by the British Columbia Public Interest Advocacy Centre ("BCPIAC") that, absent an application by a utility, then pursuant to Section 58 of the Utilities Commission Act, a review of BC Gas' revenue requirements may only proceed on the Commission's own motion or on the complaint of another party if there is reason to believe that the Utility's rates are not just, reasonable or sufficient.

The withdrawal was supported by the B.C. Health Services Ltd., the Inland Industrial Group and the BCPIAC. Avista Energy Canada Ltd. and IGI Resources Inc. endorsed the BC Gas withdrawal of the Application, without such withdrawal being subject to any actual or implied conditions that are different from the regulatory and financial treatment that BC Gas has received in the past. Fording Coal Limited acknowledged that the BC Gas information supported a withdrawal of the Application, but that concerns remain related to deferral account treatment and other issues. The B.C. Hot House Growers Association took no position on the withdrawal and relied on the Commission to ensure that all participants received fair treatment.

The Lower Mainland Gas Users Association ("LMGUA") objected to the withdrawal, raising three issues and a number of technical points.

One issue relates to the proposed acquisition of Centra BC by BC Gas Inc. and the impact that transaction may have on the establishment of base-year revenue requirements, which in turn may form the basis of a multi-year PBR rate settlement. The Commission agrees that the impact of the Centra BC acquisition should be included in any base-year analysis and that those implications will not be known until later next year. In addition, BC Gas' application to create CustomerWorks through a joint venture with Enbridge and the outsourcing of call centre and customer information system activities of BC Gas will also be decided in the near future and could have significant impacts on base-year calculations. The Commission finds that it would be preferable to delay the determination of base-year costs for the purposes of developing a multi-year PBR until the implications of the proposed Centra BC acquisition and CustomerWorks are better understood.

The second issue revolves around the reasonableness of the current distribution margins as they would apply in 2002 and whether there is adequate justification to initiate a review of BC Gas' revenue requirements, recognizing the cost and inconvenience to all parties. The Commission shares some of the concerns raised by the LMGUA that the information provided by BC Gas, including the November 9, 2001 submission, does not provide a detailed analysis of all potential impacts on customers from possible deficiencies in revenues or unforeseen benefits that will be achieved by BC Gas. However, the attachments to the November 9, 2001 BC Gas submission provide a prima facie case that the ratepayers are not disadvantaged and are likely to benefit from the withdrawal of the Application. After considering all of the submissions, the Commission finds that the withdrawal is in the interests of ratepayers, the Utility and the Utility shareholders.

The third broad concern that has been raised is that fundamental information with respect to the Utility will be lost if the existing revenue requirements review does not proceed: the conditional withdrawal will avoid a detailed scrutiny of BC Gas' operations and the prudency thereof. This concern has been expanded to include the potential difficulty in making an "apples to apples" assessment of BC Gas next year after the acquisition of Centra BC is complete. To avoid this concern, the Commission directs BC Gas to provide its Revenue Requirements Application for 2003 with sufficient information on a stand-alone basis to establish base year revenue requirements for a multi-year PBR rate setting. The information is to include the identification of services provided to Centra BC and the efficiencies which will accrue to BC Gas. These services would likely include head office support, gas supply, operational control, legal, engineering and other services. The information is to clearly identify costs and benefits associated with CustomerWorks, if approved.

The Commission finds that it is in the public interest to approve the withdrawal of the 2002 Revenue Requirements Application as proposed by BC Gas.

With this withdrawal, next year's revenue requirements review will need to be more thorough to account for the many changes to BC Gas operations over the past five years and the impact of the acquisition of Centra BC. BC Gas is directed to file its full Revenue Requirements Application for 2003 with the Commission by May 31, 2002. To ensure clarity with respect to the filing by BC Gas next year, the Commission has the following directions with respect to specific issues raised by intervenors:

1. The joint venture with Enbridge to create CustomerWorks will be reviewed in a separate process but intervenors will be invited to provide comments prior to the Commission's Decision. The potential benefits of the Joint Venture, if approved, for each of the years 2003 and beyond will be included in future revenue requirements applications.

2. The issue of the transfer of incremental bad debt expense to the Gas Cost Reconciliation Account will be addressed in the 2003 Revenue Requirements Application.

3. BC Gas is to continue its accounting for Southern Crossing Project ("SCP") third-party revenues as proposed in its withdrawal.

4. BC Gas' return on equity is not an issue for 2002, since the BC Gas delivery margins are to remain unchanged (except for approved rate design changes and rate riders) and the actual return on equity for BC Gas will be the residual of the costs and revenues for the year as proposed by BC Gas in its withdrawal.

5. BC Gas will not apply for rate changes due to changes in 2002 income taxes, corporation capital tax, or property taxes, and changes to property taxes in 2002 will not be recorded in the Property Tax Deferral Account. The Commission agrees to this tax treatment largely because BC Gas will not seek any increases in delivery margins due to rate base additions from regular capital and Certificates of Public Convenience and Necessity.

6. The Commission approves the maintenance of the Rate Stabilization Adjustment Mechanism ("RSAM") with its previously approved consumption expectations. The Commission believes that this process will be preferable to the suggestion that the RSAM deferral account be offset against the SCP third-party revenue deferral account. Since RSAM is a cost to residential and commercial customers and the SCP revenue is a benefit to a broader group of ratepayers, it would be inappropriate to offset the two deferral accounts.

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

LETTER NO. L-48-02

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 2013

VIA FACSIMILE

December 5, 2002

Mr. Dietz Kellmann
Director
Financial Development Services
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C. V3S 2X7

Dear Mr. Kellmann:

Re: BC Gas Utility Ltd. ("BC Gas")
Southern Crossing Pipeline Capacity
PG&E Energy Trading, Canada Corporation

Commission Order No. C-11-99 approved a Certificate of Public Convenience and Necessity for the Southern Crossing Pipeline ("SCP") project. The Order also approved a Firm Tendered Transportation Service Agreement ("Transportation Agreement") for approximately 52,500 Mcfd of SCP capacity (from Yahk or Kingsvale to Huntingdon) with PG&E Energy Trading, Canada Corporation ("PG&E"), and accepted for filing a Peaking Gas Purchase Agreement with PG&E. The Transportation Agreement has a primary term to October 2010 and requires PG&E to pay BC Gas Utility Ltd. ("BC Gas") $3.6 million per year. PG&E has an option to extend the agreement to October 2020.

By letter dated December 5, 2002 (the "Application"), BC Gas advised the Commission that PG&E is encountering financial difficulties. The Application requests Commission approval for a set of transactions that are designed to preserve the value of the SCP capacity contracted to PG&E for BC Gas and its customers. These transactions are summarized as follows:

- PG&E and BC Gas will terminate the Transportation Agreement and the Peaking Gas Purchase Agreement effective January 1, 2003. PG&E has also agreed to assign an equivalent amount of upstream TransCanada PipeLines Ltd. Nova/ANG ("TCPL") capacity to BC Gas effective January 1, 2003. BC Gas has agreed to make certain payments to PG&E over the period through October 2019 and PG&E has an option to convert the payment stream to a net present value payment.

- BC Gas will enter into a firm service contract with Northwest Natural Gas Company ("NWN") for 46,500 Mcfd of SCP capacity for the period November 2004 through October 2020. Effective November 1, 2004, BC Gas will also assign an equivalent amount of TCPL service to NWN.

The transactions are likely to reduce BC Gas revenue from the PG&E SCP capacity in 2003 and 2004, notwithstanding efforts to mitigate the losses. However, over the term of the transaction, BC Gas revenue will increase significantly, for the benefit of customers. The charges to be paid by NWN are substantially greater than those in the Transportation Agreement with PG&E. The Application states that the NWN charges exceed the current short to medium term market value of the TCPL/SCP transportation path as indicated by current forward prices, while in the long term, the charges represent to cost of adding new firm transportation capacity to the region. This indicates that the charges justify contracting most of the SCP capacity to NWN rather than retaining it for the benefit of core customers. The NWN payments will also cover the cost of replacing the gas supply available under the Peaking Gas Purchase Agreement.

The Commission confirms that it is prepared to approve the foregoing agreements with PG&E, TCPL and NWN substantially as described in the Application, provided the set of transactions are completed as a package so that BC Gas customers are not unduly exposed. The Application requests confidentiality for the filed agreements and BC Gas has confirmed that the request refers to the transportation service agreement with NWN. The NWN agreement would normally become a public document when it is approved as a Tariff Supplement, unless BC Gas provides sufficient justification for holding it confidential.

In the Application, BC Gas proposes to use both the SCP and TCPL capacity as core assets until November 2004. After that date, the residual amount of SCP and TCPL capacity will likely continue to be used in that way. Recording costs and mitigation revenue related to the TCPL capacity in the Gas Cost Reconciliation Account is generally consistent with the treatment of Duke Energy Gas Transmission service, and mitigation revenue is expected to substantially offset the cost of this capacity. The Commission approves the request with respect to TCPL capacity.

Revenue from PG&E under the Transportation Agreement is margin revenue. BC Gas proposes to record mitigation revenue from the SCP capacity in the existing SCP margin recovery account. The Commission determines that, at least until November 1, 2004, variances from the forecast amount of revenue from the PG&E SCP capacity and related mitigation revenue should be recorded in a SCP third party revenue mitigation account. BC Gas is directed to track such losses and revenue as a separate category within the account. At a future date, the Commission will determine the timing and method by which balances in the sub-account are flowed to BC Gas customers.

The Application also requests approval of an incentive program for mitigation revenue related to the set of transactions. The Commission confirms that mitigation revenue related to the TCPL capacity may be included as Eligible Transportation and Storage Margin under the Gas Supply Mitigation Incentive Program for 2002/03 that was approved by Order No. G-79-02. The Commission is not persuaded that an incentive program for SCP capacity mitigation has merit, and declines to approve such an incentive.

The Application further requests Commission approval of several related matters that involve BC Gas Inc. BC Gas states that $5.6 million will have been spent on the Inland Pacific Connector (“IPC”) project by April 2003, and requests approval to recover these development and marketing expenditures from BC Gas customers in the event the IPC project does not proceed.

NWN submitted a bid for IPC capacity in the IPC Open Season, and has continued to support the project. The Application states that IPC development and marketing efforts were necessary to capture the value for SCP capacity that will be realized by the agreement with NWN. Nevertheless, BC Gas has a longstanding business relationship with NWN related to matters such as Mist gas storage. Also, BC Gas customers funded activities like the regional resource planning work, which concluded that benefits would result from moving gas from Alberta to the Pacific Northwest region. As development of the IPC project is continuing, it would be premature to make a determination on the disposition of costs in anticipation that the project may not proceed. If the IPC project is deferred substantially, the Commission is prepared to receive and review an application for approval to recover some or all IPC expenditures from BC Gas customers based on the value that IPC expenditures have had for customers, including the contribution to the present arrangement with NWN.

The Application also requests that in the event British Columbia Hydro and Power Authority ("B.C. Hydro") exercises its Put Option to assign its SCP capacity to BC Gas Inc., BC Gas will accept return of the capacity. BC Gas may have greater flexibility than BC Gas Inc. to mitigate losses resulting from the return of this capacity. The Commission is prepared to approve the return of the B.C. Hydro SCP capacity provided BC Gas is reimbursed for any net costs or losses that result.

The purpose of the set of transactions, which BC Gas proposes in the Application, is to preserve the value of the SCP capacity currently held by PG&E. In all the circumstances, it is essential that the transactions be completed without delay. Recognizing that the evidentiary portion of the BC Gas 2003 Revenue Requirements Proceeding is closed, the Commission is treating the Application as a new order of business. The effect of the transactions will have a nominal, if any, impact on 2003 rates for BC Gas. For commercial reasons, the Commission will hold this letter confidential until January 1, 2003.

Yours truly,

Original signed by:

Robert J. Pellatt

RJP/cms

BRITISH COLUMBIA UTILITIES COMMISSION

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-7-03

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by BC Gas Utility Ltd.
for Approval of 2003 Revenue Requirements

BEFORE:	P. Ostergaard, Chair	)	
	R.D. Deane, Commissioner	)	February 4, 2003
	K.L. Hall, Commissioner	)	

O R D E R

WHEREAS:

A. On June 17, 2002, BC Gas Utility Ltd. ("BC Gas") filed a 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application ("the Application"), pursuant to Sections 58 and 61 of the Utilities Commission Act ("the Act"), for approval to establish a revised Schedule of Rates on a permanent basis effective January 1, 2003; and

B. On September 16, 2002, BC Gas filed a letter summarizing the items it was seeking to have determined in the hearing process under a one-year revenue requirement framework. The letter also revised upward the revenue requirement being applied for as a result of adjustments discussed in that letter; and

C. Further revisions to the revenue requirement were noted in BC Gas' September 27, 2002 response to the second round of information requests; and

D. As requested by the Commission, two sets of issues lists were submitted by Intervenors on October 4, and on October 16, 2002 and in Letter No. L-42-02 the Commission emphasized its wish to provide all parties an opportunity to assess all issues that are relevant to establishing a one-year revenue requirement for BC Gas. It also established two working groups, one for load forecasts and the other for transportation tariff changes. Reports from these working groups were filed during the oral public hearing; and

E. On November 1, 2002, BC Gas submitted further revisions to its Application to include higher pension costs, higher industrial revenue forecasts and additional revenue deficiencies; and

F. In accordance with Commission Order No. G-63-02, an oral public hearing was conducted during the period November 12 to November 21, 2002; and

G. During the course of the oral public hearing, BC Gas revised its Application further to correct an error on an earlier revision and to make other changes, all as set out in Exhibit 42. The revised revenue deficiency for which BC Gas seeks interim rate relief is $17.4 million, an increase in overall revenue of 1.42 percent, representing a 3.73 percent increase in delivery rates. BC Gas applied to recover $11.2 million of the increase by adding 2.85 percent to the delivery rates of its "RSAM Customers", namely, residential and commercial customers. The remaining $6.2 million would be recovered by a 1.42 percent increase in delivery rates to all captive customers; and

H. By Order No. G-90-02, the Commission made BC Gas' rates interim effective January 1, 2003.

NOW THEREFORE pursuant to Sections 58 and 60 of the Utilities Commission Act, the Commission orders as follows:

1. The Commission confirms a permanent increase in revenue requirements for 2003 of approximately $12.2 million as detailed in its Decision dated February 4, 2003. BC Gas is directed to comply with all Commission directions contained in the Decision.

2. BC Gas, by way of a bill insert or customer notice, is to provide all affected customers with notification of the permanent rates. BC Gas is to provide the Commission with a draft copy of the customer notice in advance of its distribution to customers.

3. BC Gas is also directed to amend its permanent rates effective March 1, 2003 to reflect the annual revenue requirement approved by this Decision and is further directed to add a ten-month rider to its 2003 billings to recover the difference between its interim rates and permanent rates for the months of January and February 2003.

4. The Commission will accept, subject to timely filing, amended Gas Tariff Rate Schedules in accordance with the terms of this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 4th day of February 2003.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Appendix M

TERASEN GAS INC.
SCP DEFERRAL ACCOUNT CONTINUITY SCHEDULE 17912

Particulars	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Opening Balance	$ -	$ (5,387,315)	$ (3,857,583)	$ (2,455,527)	$ (1,270,095)	$ (469,239)	$ 655,000	$ 1,179,000	$ 917,000	$ 655,000	$ 393,000	$ 131,000
Before Tax												
Deferred Revenues	3,744,600	3,744,600	1,300,000	1,000,000	1,000,000	1,000,000	1,000,000	-	-	-	-	-
SCP Mitigation	(13,279,670)	(1,257,231)	(306,212)	(190,180)	(571,212)							
Subtotal	(9,535,070)	2,487,369	993,788	809,820	428,788	1,000,000	1,000,000	-	-	-	-	-
Part I Tax Rate	43.50%	38.50%	36.50%	34.50%	34.50%	34.50%	34.50%	34.50%	34.50%	34.50%	34.50%	34.50%
Tax Offset for Deferred Revenue / SCP Mitigation	4,147,755	(957,637)	(362,733)	(279,388)	(147,932)	(345,000)	(345,000)	-	-	-	-	-
After Tax Cost	(5,387,315)	1,529,732	631,055	530,432	280,856	655,000	655,000	-	-	-	-	-
Amortization												
Deferred Revenue / SCP Mitigation			771,000	655,000	520,000	469,239	(131,000)	(262,000)	(262,000)	(262,000)	(262,000)	(131,000)
Balance, End of Year	$ (5,387,315)	$ (3,857,583)	$ (2,455,527)	$ (1,270,095)	$ (469,239)	$ 655,000	$ 1,179,000	$ 917,000	$ 655,000	$ 393,000	$ 131,000	$ -

	2004	2005
Forecast as per Tab 3 11.1 & 11.3	(1,175,000)	(175,000)
Variance	(95,095)	(294,239)

TERASEN GAS INC.
SCP DEFERRAL ACCOUNT CONTINUITY SCHEDULE 17913

Particulars	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Opening Balance	$ -	$ 863,814	$ 1,770,729	$ 1,387,698	$ 1,027,932	$ 495,552	$ 396,442	$ 297,331	$ 198,221	$ 99,110
Before Tax										
Deferred Revenues	1,784,600	1,784,600	-	-	-	-	-	-	-	-
SCP Mitigation	(255,725)	(309,942)	(45,718)	(1,170)	(283,023)					
Subtotal	1,528,875	1,474,658	(45,718)	(1,170)	(283,023)	-	-	-	-	-
Part I Tax Rate	43.50%	38.50%	36.50%	34.50%	34.50%	34.50%	34.50%	34.50%	34.50%	34.50%
Tax Offset for Deferred Revenue / SCP Mitigation	(665,061)	(567,743)	16,687	404	97,643	-	-	-	-	-
After Tax Cost	863,814	906,915	(29,031)	(766)	(185,380)	-	-	-	-	-
Amortization										
Deferred Revenue / SCP Mitigation			(354,000)	(359,000)	(347,000)	(99,110)	(99,110)	(99,110)	(99,110)	(99,110)
Balance, End of Year	$ 863,814	$ 1,770,729	$ 1,387,698	$ 1,027,932	$ 495,552	$ 396,442	$ 297,331	$ 198,221	$ 99,110	$ -

	2004	2005
Forecast as per Tab 3 11.1 & 11.3	1,025,000	648,000
Variance	2,932	(152,448)

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26/07/2005

TERASEN GAS INC.
SCP DEFERRAL ACCOUNT CONTINUITY SCHEDULE 17936

Particulars	2003	2004	2005	2006	2007	2008	2009	2010
Opening Balance	$ -	$ 888,792	$ 2,606,663	$ 2,644,038	$ 1,983,429	$ 1,322,820	$ 662,210	$ 1,601
Before Tax								
Deferred Revenues	3,600,000	3,000,000						
SCP Mitigation	(2,200,327)	(514,796)						
PG&EEC Termination Payments to David Pope		137,500	825,000					
Subtotal	1,399,673	2,622,704	825,000	-	-	-	-	-
Part I Tax Rate	36.50%	34.50%	34.50%					
Tax Offset for Deferred Revenue / SCP Mitigation	(510,881)	(857,395)	-					
PG&EEC Termination Payments		(47,438)	(284,625)					
After Tax Cost	888,792	1,717,871	540,375	-	-	-	-	-
Amortization								
Deferred Revenue / SCP Mitigation			(503,000)	(503,000)	(503,000)	(503,000)	(503,000)	(1,601)
PG&EEC Termination Payments				(157,609)	(157,609)	(157,609)	(157,609)	-
Balance, End of Year	$ 888,792	$ 2,606,663	$ 2,644,038	$ 1,983,429	$ 1,322,820	$ 662,210	$ 1,601	$ -
Forecast as per Tab 3 11.1 & 11.3		2,517,000	2,014,000					
Variance		89,663	630,038					

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26/07/2005

1.0 Reference: Exhibit B-1, Page 2, Item 6

***Preamble**: The Application states "First, in the event BC Hydro exercises its Put Option to assign its SCP capacity to Terasen Inc., Terasen Gas would accept return of the capacity, as the Company, as compared to Terasen Inc., may have greater flexibility in managing and optimizing the capacity."*

(a) In proposing that Terasen Gas accepts return of the capacity, how is Terasen Gas going to track any net costs or losses that may result from the use of SCP?

Response:

Please refer to BCUC IR1, Response to 7.2.

(b) Rather than accepting the return of the SCP capacity, has Terasen Gas considered charging Terasen Inc. a fee for the management and optimization of the service that could be provided by SCP?

Response:

Terasen Gas Inc. has evaluated the SCP resource as it would any other resource and determined that by incorporating the SCP capacity into its portfolio it is providing core customers with the best alternative of saving an estimated $2-3 million/year for core customers.

Please refer to BCUC IR1, Response to 6.5.

2.0 Reference: Exhibit B-1, Page 5

***Preamble**: The Application states "NWN (Northwest Natural Gas Company) was seeking firm transportation service from Alberta to Huntingdon and had made a firm commitment to contract for transport capacity on the proposed IPC project."*

(a) Did NWN first approach Terasen Gas for service or did Terasen Inc. solicit NWN to see if they were interested in service?

Response:

Prior to issuing the IPC Open Season, Terasen held discussions with many prospective shippers, principally the regional electric and gas utilities, marketers, industrials, and power generators, including both NWN and BC Hydro. At the time, NW Natural was evaluating their options for firm capacity upstream from Sumas and expressed strong interest in IPC. Subsequently NWN agreed to contract for capacity in response to the IPC Open Season.

(b) How much capacity on IPC was NWN committed to contract and did NWN have an exit clause in the firm commitment? If an exit clause is in the contract, please provide details of the exit clause.

Response:

NW Natural's request for service during the Open Season matched its current capacity on Southern Crossing Pipeline. As provided in the Open Season documents, if IPC had proceeded, the request for service was binding however for a certain period of time, Shippers were able to reduce their contract capacity commitment if Shippers were unable to contract for firm upstream capacity on TransCanada, and or if as a result of the amount of contracted capacity, the initial demand charge was forecast to be above a certain level. These provisions are described in the Open Season documents provided in response to BCUC IR No. 9.2.

The IPC firm service transportation agreements would not have included an exit clause. The NW Natural SCP Transportation Service Agreement does not contain an exit clause.

3.0 Reference Exhibit B-1, Page 5

***Preamble**: The Application states "The parent company of PG&E was in grave financial difficulty (PG&E Corp subsequently entered into bankruptcy protection) and Terasen Gas was seeking to protect the SCP revenue it received from PG&E."*

(a) Did PG&E have any assignment rights under its SCP Service Agreement with Terasen Gas?

Response:

PG&E had the identical assignment rights under its SCP TSA and Peaking Agreement as BC Hydro. Please see response to BCUC IR No. 6.4 for a description of these rights.

(b) Did Terasen Gas enter into any discussions with PG&E, or was Terasen Gas aware of any attempts by PG&E, to divest itself of the SCP service prior to it running into financial difficulty?

Response:

We are not aware of any attempts by PG&E to divest itself of the SCP service prior to running into financial difficulty. Terasen Gas initiated the discussions with PG&E in order to mitigate its risk that PG&E would default, and to enable a long term arrangement to be put in place with NW Natural that contributed significant benefits.

(c) Please explain what risk Terasen faced with creditors if PG&E defaulted that would have prevented Terasen from utilizing the PG&E capacity on SCP.

Response:

Please see response to BCUC IR No. 14.2.

4.0 Reference: Exhibit B-1, Page 5

***Preamble**: The Application states that "Terasen Gas used the released SCP capacity to provide firm transportation service to NWN effective November 2004, in the amount of 46.5 MMcfd, along with a corresponding amount (46.5 MMcfd plus fuel) of TCPL capacity, back to the AECO trading hub. The demand charges to be paid by NWN for this capacity were based on a discount to the expected cost of capacity on the proposed IPC project, at the same time, they represented a significant premium to the revenue received from PG&E. In addition, the term of the contract provided for revenue certainty for an additional 10 years beyond the primary term of the PG&E contract."*

(a) In the absence of the TCPL capacity to provide firm service back to the AECO trading hub, what would be the estimated value of SCP?

Response:

The value of any asset is based on the value that a resource can bring to each individual portfolio. The estimated value of SCP capacity to the Midstream portfolio is the value that SCP brings to the portfolio estimated to be $2 million/ year savings. The value of SCP capacity to NWN would be the value that they were willing to pay for the SCP capacity.

(b) Please discuss why the tolls paid by NWN would be based on a discount to the IPC and not the market value for existing SCP service plus tolls to AECO. Are the tolls paid by NWN linked to the peaking arrangements used to replace the PG&E Peaking Agreement?

Response:

The tolls were the result of negotiation between NW Natural and Terasen Gas. Please see the response to BCUC IR No. 1.5 for further discussion.

(c) Please provide terms for the release of TCPL capacity held by PG&E to Terasen Gas. What portion of the termination payments made to PG&E was for the release of TCPL capacity?

Response:

The TCPL capacity that was held by PG&E was assigned to Terasen Gas and subsequently a portion of that capacity was assigned to NW Natural pursuant to the standard terms and conditions of the TCPL tariff.

The termination payments made to PG&E were negotiated based on the set arrangements as a whole, not on the separate components. Terasen Gas is not aware of what value PG&E may have allocated to this part of the transaction.

5.0 Reference: Exhibit B-1, Page 6

***Preamble**: The Application states "The Company also credited the SCP deferral account with the mitigation revenue, as directed, with a corresponding debit entry to the MCRA. Given forward prices at the time of the 2002 Application, Terasen Gas expected to realize $2.0 million in mitigation revenue over the 22-month period. Actual recorded mitigation revenue was $2.7 million, which was credited to the deferral account. This resulted in a total balance before tax effect in the deferral account of approximately $3.9 million, at December 31, 2004"*

(a) Please describe the basis on which the mitigation revenue was derived. Please explain if the transactions were independent of other transactions for Terasen Gas transport and supplies. If not, how did they impact other supply related costs? How did mitigation revenues for Terasen Gas compare over the 22-month periods with the prior 2 years over the same 22-month time frame? Please provide a summary.

Response:

Please see BCUC IR1 Response to No. 7.4.1. All Terasen Gas customers receive the benefit of the revenue mitigation related to the SCP deferral account. This mitigation revenue is filed every year with the Commission and is based on pre-approved Commission formulas. The mitigation revenue is the result of optimization of the Terasen Gas Midstream transportation under market conditions that vary from year to year.

6.0 Reference: Exhibit B-1, Page 9

***Preamble**: The Application states "Typically, SCP capacity would be backed with TCPL (BC and Alberta) transportation to provide access to Alberta supply. However, Terasen Gas will not acquire additional TCPL capacity but instead optimize its existing pipeline capacity (TCPL and Westcoast) on normal days and acquire Kingsgate supply for design peak days. Terasen Gas forecasts the net impact of the Kingsgate arrangement to provide a benefit to Terasen Gas' customers, as compared to the BC Hydro peaking option, of approximately $280,000 per year, realized as a reduction to the MCRA."*

(a) Please discuss what pricing assumptions has Terasen Gas used for Kingsgate supply. Please provide any analysis Terasen Gas has made of the liquidity at Kingsgate and any historical data it has used to estimate pricing at this point during peak periods.

Response:

Terasen Gas has evaluated the last 5 years of daily pricing to determine the maximum daily price volatility at Kingsgate. The price volatility is derived by applying the statistical method of taking the annualized standard deviation of the LN of daily winter prices changes. Please see BCUC IR Response #4.3 on how the price volatility is applied to determine daily winter pricing.

Terasen Gas can evaluate the Kingsgate liquidity by comparing it to other regional markets like Sumas. Approximately 2.5 bcfd of supply flows through the Kingsgate market south to primarily the Malin market which typically trades two times the volume of the Sumas market place. Kingsgate is also sourced directly from the 12 bcfd AECO hub that not only is the largest trading hub in the west, but trades all day and has an active intraday market. The Huntingdon market is sourced primarily from a 2 bcfd market at Station 2 which trades within a one hour window each morning for next day flows and a very limited intraday market.

To secure a peaking supply at Kingsgate Terasen Gas will purchase a physical call option from a counterparty that may on a daily basis flow the supply to Malin or may sell the supply at Empress. The physical call option provides Terasen Gas the right but not the obligation to call this supply any 15 days during the winter months. For this right Terasen Gas will pay a nominal demand charge of which Terasen Gas has estimated to be about US$0.05/Mmbtu. To date Terasen Gas has received offers for call options at Kingsgate with lower demand charges than stated in the application.

A counterparty that holds TCPL capacity could view the sale of a call option at Kingsgate as an opportunity to mitigate the TCPL capacity over and above the value that the counterparty is able to mitigate on a daily basis. I.e., each day the TCPL holder can recover at least 2/3 of the TCPL costs by selling at Empress. The sale of a 15 day call option at Kingsgate does not hinder the counterparty from recovering the daily mitigation in fact the counterparty receives a demand charge that is additional to the daily mitigation.

(b) Has Terasen Gas prepared any analysis of the relative risk (in terms of both price and liquidity) of purchasing gas at Kingsgate vs. AECO during design peak days? If so, please provide the results of that analysis.

Response:

The AECO market is more liquid than the Kingsgate market, however Terasen Gas has explored the Kingsgate market and found that currently there are a number of interested parties holding TCPL capacity that are willing to offer Kingsgate peaking.

The table below outlines the comparison between AECO and Kingsgate.

AECO	Station 2	Hunt	Kingsgate	Stanfield
Large number of buyers and sellers	Limited number of buyers and sellers	Limited number of buyers and sellers	Limited number of buyers and sellers	Limited number of buyers and sellers
Significant amount of gas purchased and sold on a daily and monthly basis	Relatively smaller amount of gas sold on a daily and monthly basis	Relatively smaller amount of gas sold on a daily and monthly basis	Relatively smaller amount of gas sold on a daily and monthly basis. Sourced from AECO physical hub the largest trading hub in the West.	During the winter this location is sourced from AECO and Rockies and priced off of AECO, Rockies, Malin and Huntingdon. Rockies physically trades four times the Huntingdon volume and Malin physically trades two times the Huntingdon volume.
Financial transactions readily available	Financial transactions priced off AECO index creating a Station 2/AECO basis risk	Financial transactions priced off AECO index or Huntingdon	Financial transactions priced off AECO index, Huntingdon and Malin.	Financial transactions priced off AECO index, Huntingdon, Rockies and Malin.
Tight bid-ask spread	Relatively wider bid-ask spread	Relatively wider bid-ask spread	Relatively wider bid-ask spread	Relatively wider bid-ask spread
A number of storage facilities allowing large volumes to enter/leave the market without associated transportation costs, including fuel	A single storage facility, limited storage holders with associated transportation and fuel costs to and from storage.	Pacific Northwest and Rockies storage may be used to supply this location.	Sourced from AECO which has a number of storage facilities.	Pacific Northwest and Rockies storage used to supply this location.

Pipeline rules which facilitate gas movements in and out of storage	Pipeline rules which increase the cost of moving gas in and out of storage which reducing its use as a market clearing tool	Westcoast Pipeline rules which increase the cost of moving gas in and out of storage which reduces its use as a market clearing tool.	Pipeline rules which facilitate gas movements in and out of storage. Kingsgate is supplied by Alberta supply.	NPC Pipeline rules which facilitate gas movements in and out of storage.

(c) *Please provide a detail breakdown of the estimated $280,000 per year savings anticipated by replacing the BC Hydro peaking with the Kingsgate arrangement, including a list of any assumptions that were used.*

Response:

Please see response to BCUC IR1, 4.3.

(d) *Please state the assumptions used relating to the transportation arrangement and cost for the Kingsgate peaking supply to the Lower Mainland if not already stated in the response to BCH IR 6(c).*

Response:

Please see response to BCUC IR1, 4.3.

(e) *Rather than sourcing the peaking supply from Kingsgate, please indicate what would be the estimated cost for sourcing peaking supply downstream of Huntingdon.*

Response:

The Downstream Storage or an LNG resource would net a greater benefit. However, note that the when the Midstream evaluates the impact of a resource to the existing portfolio it does so as a whole.

(f) *Please identify what provisions have been put in place to track actual savings and whether any mechanism has been put in place to apply any difference back to Terasen Inc. In this response, please address the rationale for applying the impact of the Kingsgate arrangement to the MCRA instead of attributing it to Terasen Inc.*

Response:

Please BCUC IR1 response 7.2.

7.0 Reference: Exhibit B-1, Page 11

***Preamble**: The Application states "TGVI believes that the agreement with NWN, along with the resulting significant revenues would not likely have been realized if the IPC project had not been under development."; and "In addition, Terasen Gas submits, the development of IPC prompted Westcoast to respond with its own expansion project, which in turn leads to the successful negotiation of the Kingsvale South tolls with Westcoast in 2002."*

(a) Does TGVI (Terasen Gas) believe that they would not have been able to broker arrangements with NWN and PG&E to transfer the SCP capacity if they did not have the IPC project under development? If not, please discuss why not.

Response:

Please see response to BCUC IR No. 14.3. If IPC had not been under development, NWN likely would have put other arrangements in place before the opportunity to negotiate a deal with PG&E presented itself.

(b) Please discuss what makes Terasen Gas believe that Westcoast was responding to IPC development and not the same market conditions that made Terasen Gas believe the addition of ICP was necessary.

Response:

Terasen Gas recognises that as in the case of IPC, Westcoast was unlikely to proceed with an Open Season if it did not believe that the market conditions supported a capacity expansion. Terasen believes, however, that Westcoast's open season and the expansion project schedule was timed to ensure that it would be competitive with IPC.

(c) In the NEB Decision (RH-2-98), the Board denied Terasen's request for a Kingsvale South toll for SCP but stated that "a future expansion of the Westcoast system may give rise to a situation where a fundamental re-examination of the Westcoast tolling system is required". When Westcoast announced its open season for an expansion of its Southern Mainline, Terasen Gas already had grounds to seek a Kingsvale South toll. Does Terasen Gas expect the outcome of the negotiations for a Kingsvale South toll would have been any different if IPC was not under development? If so, please discuss why.

Response:

Please see response to BCUC IR No. 9.5.3.

8.0 Reference: Exhibit B-2, Page 7

***Preamble** : In Exhibit B-2, the submission states "If BCGUL (Terasen Gas) is able to replace T-South long haul capacity with SCP(BCH) and TCPL capacity in the core portfolio, core customers will have a positive benefit."*

(a) Terasen compares the value of the Duke T-South capacity to the combination of SCP and TCPL capacities in its 2002 Application to terminate PG&E SCP Transport and Peaking agreements. Please explain why in the current Application it is no longer necessary to include the TCPL firm capacity with SCP in the replacement of the Duke T-South capacity.

Response:

Terasen Gas did evaluate the TCPL capacity scenario versus the BC Hydro option and determined there was a net benefit of approximately $500K. Terasen Gas determined that even though the AECO/TCPL option versus the BC Hydro Peaking did provide a greater net benefit than the Kingsgate peaking versus BC Hydro Peaking option Terasen Gas would abstain from acquiring additional TCPL capacity until resolution of the current NGTL rate design hearing, which is scheduled to end prior to November 1, 2005.

Currently NGTL and TCPL BC system are looking at introducing winter short term firm and Terasen Gas anticipates this process will be completed within the next year. If and when new rates are developed Terasen Gas will re-evaluate whether to pick up Kingsgate peaking or short term firm on TCPL. Terasen Gas will also continue to evaluate the Kingsgate market particularly if there is a large amount of de-contracting on TCPL. The decision to contract at Kingsgate and not contract incremental TCPL capacity does not preclude Terasen Gas from evaluating this option in the future.

TERASEN GAS INC.
APPLICATION FOR APPROVAL OF TRANSACTIONS RELATED TO THE SOUTHERN CROSSING PIPELINE AND INLAND PACIFIC CONNECTOR

RESPONSE TO
INLAND INDUSTRIALS
INFORMATION REQUEST NO. 1

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1. ***Reference:*** *Application, page 8 of 16*

Preamble: *Terasen states "BC Hydro's exercise of the Put Option transfers the obligation from BC Hydro to Terasen Inc. to pay SCP demand charges that are currently paid to Terasen Gas and allocated as revenue included in the delivery margin."*

Request:

(a) If Terasen Inc. remained obligated to pay the SCP demand charges, would Terasen Gas continue to allocate the revenue received from Terasen Inc. to the delivery margin?

Response:

Yes. The effect of the BC Hydro put option is to put the rights and the obligations of the BC Hydro SCP TSA and Peaking Agreement to Terasen Inc effective November 2005. Terasen Inc.'s obligation to pay the SCP demand charges are therefore the same as BC Hydro's current obligations and the revenue received would be treated in the same way.

(b) Apart from the proposal in the Application, what are Terasen Inc.'s options to mitigate the cost of the SCP demand charges obligation?

Response:

The proposal in the application is to terminate the SCP TSA and Peaking Agreement on the November 2005, when BC Hydro's Put comes into effect. Terasen Gas would then retain the SCP capacity for its own use and optimise its portfolio accordingly. An alternative to this proposal would be for the agreements to stay in place and for Terasen Inc to mitigate its demand charge obligation by putting in place separate arrangements with Terasen Gas or other parties.

Please see response to BCUC IR1, No. 6.5 for further discussion.

(c) Is one of Terasen Inc.'s mitigation options to sell the SCP capacity to Terasen Gas at its fair market value, or at least a price close to but less than Terasen Gas's avoided cost in its Midstream portfolio of resources?

Response:

Yes, if the agreements are not terminated, Terasen Inc retains the rights and obligations to the SCP capacity and would seek to maximise the value of through other transactions. One option would be to sell the SCP capacity to Terasen Gas at a price close to but less than Terasen Gas's avoided cost in its Midstream portfolio of resources.

(d) If the option described in (c) was implemented, how would Terasen Gas allocate the costs and benefits?

Response:

In the scenario where the agreements are not terminated, Terasen Inc would continue to pay the $3.6 million in demand charges to Terasen Gas which revenue is subsequently allocated to the delivery margin as discussed in the response to IR1(a) above.

If Terasen Gas in turn takes the SCP capacity into its Midstream portfolio of resources and subsequently pays Terasen Inc for use of the capacity, it would optimise its other resources to maximise the savings that the SCP capacity could provide. Any cost savings would therefore flow to the Midstream portfolio. The size of the benefit to Midstream would depend on the net difference between the price Terasen Gas pays Terasen Inc and the cost savings it can realise through optimisation of its Midstream portfolio.

2. ***Reference:*** *29 June 2005 Workshop Powerpoint Presentation, slides 37 and 38*

Preamble: *Slides 37 and 38 illustrate the customer allocations and financial impacts of the proposals in the application.*

Request:

(a) *Please prepare tables similar to those shown on slides 37 and 38 for the following two scenarios:*

Scenario 1:

- *Terasen Inc. retains the obligation to pay the SCP demand charges for the balance of the primary term – i.e. 31 October 2010.*
- *Terasen Gas continues to allocate the revenue from Terasen Inc.'s payments to the delivery margin.*
- *Terasen Gas does not recover the IPC costs from its ratepayers.*

Response:

In this scenario the SCP agreements that would stay with Terasen Inc and continue to be in force for the remaining term of the primary period (e.g. to October 31 2010) and Terasen Gas does not incorporate the SCP capacity into its midstream portfolio. There is therefore no change to the midstream related to the BC Hydro Put Option, however the margin account is credited the demand charge revenues received from Terasen Inc. The reduced SCP 3rd party revenue applies to the revenues previously received from PG&E & BC Hydro and now replaced by NWN revenues and Terasen Inc revenues.

2006		
Midstream	**Transaction**	**Margin**
$1,131	PG&E Termination and NWN Agreements	$5,812
$0	**BC Hydro / Terasen Inc. SCP Capacity**	$3,600
$0	IPC Development Costs	$0
$1,131	Total Benefit / (Costs) of new Transactions	$9,412
$0	**Reduced SCP Revenues from PG&EEC & BC Hydro**	-$7,200
$1,131	**Net Benefit (Cost)**	$2,212
Revised Attachment 3a @ 6.02% ($000's)		

Page 37 from the Work Shop Handout total Net Benefit related to the Midstream is $3,537 versus the $1,131 above.

NPV thru 2010		
Midstream	**Transaction**	**Margin**
$5,560	PG&E Termination and NWN Agreements	$30,715
$0	**BC Hydro / Terasen Inc. SCP Capacity**	$14,296
$0	IPC Development Costs	$0
$5,560	Total Benefit / (Costs) of new Transactions	$45,010
$0	**Reduced SCP Revenues from PG&EEC & BC Hydro**	-$31,987
$5,560	**Net Benefit (Cost)**	$13,024
Revised Attachment 3a @ 6.02% ($000's)		

<u>Scenario 2</u>:

- *Terasen Inc. retains the obligation to pay the SCP demand charges for the balance of the primary term – i.e. 31 October 2010.*
- *Terasen Inc. resells the BC Hydro SCP capacity to Terasen Gas at $1 less than Terasen Gas's estimated avoided cost.*
- *Terasen Gas continues to allocate the revenue from Terasen Inc.'s payments to the delivery margin.*
- *Terasen Gas does not recover the IPC costs from its ratepayers.*

<u>Response:</u>

In this scenario the SCP agreements that would stay with Terasen Inc and continue to be in force for the remaining term of the primary period (e.g. to October 31 2010). Separately, Terasen Gas and Terasen Inc would require an agreement whereby Terasen Gas has the use of that capacity but pays Terasen Inc an amount equivalent to the total savings to its portfolio less $1.

The resulting benefits in Scenario 2 are the same as in Scenario 1 because if **Terasen Gas** was to pay **Terasen Inc.** the avoided cost or economic rent of the value of the Westcoast Capacity, Huntingdon Downstream Resources and Kingsgate Peaking Arrangement (lines 49, 50 and 51 of Attachment 3a- revised June 29 / 05) less one dollar ($1) would not accrue to the midstream customers. The value of any benefit would have been transferred to Terasen Inc.

As before, Terasen Inc demand charges are allocated to the margin account replacing revenues previously received from BC Hydro.

2006		
Midstream	**Transaction**	**Margin**
$1,131	PG&E Termination and NWN Agreements	$5,812
-$0	**BC Hydro / Terasen Inc. SCP Capacity**	$3,600
$0	IPC Development Costs	$0
$1,131	Total Benefit / (Costs) of new Transactions	$9,412
$0	**Reduced SCP Revenues from PG&EEC & BC Hydro**	-$7,200
$1,131	**Net Benefit (Cost)**	$2,212
Revised Attachment 3a @ 6.02% ($000's)		

NPV thru 2010		
Midstream	**Transaction**	**Margin**
$5,560	PG&E Termination and NWN Agreements	$30,715
-$0	**BC Hydro / Terasen Inc. SCP Capacity**	$14,296
$0	IPC Development Costs	$0
$5,560	Total Benefit / (Costs) of new Transactions	$45,010
$0	**Reduced SCP Revenues from PG&EEC & BC Hydro**	-$31,987
$5,560	**Net Benefit (Cost)**	$13,024
Revised Attachment 3a @ 6.02% ($000's)		

Although Midstream and Delivery Margin accounts are indifferent in either Scenarios, Scenario #1 is punitive and the value is squandered as neither customers nor Terasen Inc. are able to realize incremental benefits.

(b) *Confirm that the customers included in the "Midstream" category are a subset of the customers included in the "Margin" category. What is the size of the "Midstream" set of customers relative to the "Margin" set of customers?*

Response:

The customers in the “Midstream” category are a subset of the customers included in the “Margin” category.

The relative size of the volumes (TJ) and coincident peak day demand (GJ) are provided in the following table to illustrate approximately the proportion of allocation of the margin benefits based on the approved allocation methodology for Southern Crossing Pipeline costs. The volumes (TJ) are from the approved forecast for 2005 and the load factors for sales customers are the rolling three year average for 2002 through 2004. Load factors have not been updated so the load factor for Large Commercial Rate Schedule 3 was used as a proxy for Commercial T-Service Rate Schedule 23. The load factor for General Firm T-Service Rate Schedule 25 is from the 2001 Rate Design Update filed September 14, 2001.

Particulars	Rate Schedule	2005 Sales / T-Service Volumes TJ	Proportion of Volumes %	Load Factor	Coincident Peak Day GJ	Proportion of Peak Day %
Sales Customers ("Midstream" & "Margin")						
Residential	1	73,587.7	50.9%	30.7%	656,711	56.6%
Small Commercial	2	22,448.0	15.5%	29.3%	209,902	18.1%
Large Commercial	3	17,879.4	12.4%	36.3%	134,944	11.6%
General Firm Service	5	4,806.4	3.3%	44.3%	29,725	2.6%
NGV	6	327.3	0.2%	100.0%	897	0.1%
Subtotal		119,048.8	82.3%		1,032,179	88.9%
T-Service Customers ("Margin")						
Commercial	23	5,037.6	3.5%	36.3%	38,021	3.3%
General Firm T-Service	25	12,409.8	8.6%	55.0%	61,817	5.3%
Large Industrial - Inland (Non-Bypass) [1]	22 / 22A	8,157.1	5.6%		28,937	2.5%
Subtotal		25,604.5	17.7%		128,775	11.1%
Total		144,653	100.0%		1,160,954	100.0%

(c) *What percentage of the "Margin" benefits column would be shared by the customers who share in the "Midstream" benefits? Explain the calculation.*

Response:

88.9% of the margin benefits would be allocated to the sales customers (“Midstream” category). This is the proportion of the load factor adjusted volumes (last column from table in response to 2 (b) of the sales customers relative to the total coincident peak demand for how Southern Crossing Pipeline costs are allocated.

TERASEN GAS INC.
APPLICATION FOR APPROVAL OF TRANSACTIONS RELATED TO THE SOUTHERN CROSSING PIPELINE AND INLAND PACIFIC CONNECTOR

RESPONSE TO
DIRECT ENERGY MARKETING LIMITED ("DIRECT ENERGY")
INFORMATION REQUEST NO. 1

1 Reference: TGI SCP-IPC – Exhibit B-1

On Page 6, Terasen Gas Inc. ("Terasen Gas") states that they "would acquire additional peaking resources at Huntingdon/Sumas in order to meet demand requirements for the Company's Lower Mainland service area "Lower Mainland". Terasen Gas has assumed that half of the requirement would be met by acquiring a downstream storage resource such as Mist or LNG storage within the market area and the remainder would be met through Stanfield supply. The net fixed and variable cost of these transactions is approximately $1.1 to 1.2 million per year, which would be debited to the MCRA."

DEML wishes to understand the potential impact of the allocation of peaking resources between Mist or LNG storage and Stanfield supply. If the requirement was met one-hundred percent through Mist or LNG storage, or conversely met one-hundred percent through Stanfield supply, how would this impact the value of the transactions?

Response:

LNG and Mist storage would provide the greatest benefit to the Midstream portfolio. LNG is the best option given the storage facility would be located near load areas providing increased security of supply which is the primary objective of the Midstream portfolio.

2 ***Reference: TGI SCP-IPC – Exhibit B-1***

On Page 9, Terasen Gas states it "proposes to replace the terminated BC Hydro SCP Peaking Agreement with a peaking arrangement at Kingsgate. Since supply at Kingsgate is relatively less constrained than at Huntingdon/Sumas during the winter months when gas typically moves north via Northwest Pipeline or is displaced, Terasen Gas would pay a nominal demand charge (approximately $380,000 per year) to re-direct Kingsgate supply during regional peak events that would otherwise move South to Malin."

DEML wishes to understand the liquidity of the natural gas market at Kingsgate and requests that Terasen Gas provide information as to why it perceives Kingsgate to be "less constrained" than Huntington/Sumas.

Response:

Please see BC Hydro IR response #6a.