Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

16705 Fraser Highway
Surrey, B.C. V3S 2X7
Tel: (604) 592-7784
Fax: (604) 592-7890
Email: scott.thomson@terasengas.com
www.terasengas.com

June 1, 2005

British Columbia Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Robert J. Pellatt, Commission Secretary

Dear Sir:

Re: Terasen Gas Inc. ("Terasen Gas")
Application for Approval of Transactions with respect to Southern Crossing Pipeline ("SCP") and Inland Pacific Connector ("IPC")

Please find attached an application from Terasen Gas for approval of transactions with respect to SCP and IPC.

We trust the Commission finds this application in order. Should you have any questions with respect to this application, please contact Tom Loski at (604) 592-7464.

Yours truly,

TERASEN GAS INC.

Original signed by Tom Loski

For: Scott A. Thomson

Attachments

Cc: B. Brownell, BCUC
B. Williston, BCUC
Registered Interveners in 2004 Annual Review

IN THE MATTER OF THE "UTILITIES COMMISSION ACT"
R.S.B.C. 1996, CHAPTER 473

AND IN THE MATTER OF

AN APPLICATION BY TERASEN GAS INC.

To: British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, British Columbia
V6Z 2N3

APPLICATION

Terasen Gas Inc. ("Terasen Gas" or the "Company") hereby applies pursuant to the provisions of the *Utilities Commission Act*, R.S.B.C.1996, Chapter 473 and amendments thereto (the "Act"), and in particular Sections 58, 61 and 71, for British Columbia Utilities Commission (the "Commission") approval of several transactions related to the Southern Crossing Pipeline Project ("SCP") and the Inland Pacific Connector Project ("IPC").

In respect of this Application, Terasen Gas submits that:

1. In May 1999 the Commission found that the issuance of a Certificate of Public Convenience and Necessity ("CPCN") Application for the SCP as applied for by Terasen Gas (then BC Gas Utility Ltd.), including related agreements, would be in the public interest provided several conditions precedent were met. In its Order No. G-51-99 dated May 21, 1999, the Commission concluded that the SCP offered the highest potential benefit to the ratepayers over the long-run. In part, this conclusion was based on third party transportation service and peaking gas service arrangements that help to mitigate the cost of service impacts of the new pipeline. Commission Order No. C-11-99, dated June 22, 1999, approved the CPCN and the SCP was subsequently constructed and put in service in December 2000.

2. Commission Order No. C-11-99 also approved two Firm Tendered Transportation Service Agreements with BC Hydro and Power Authority ("BC Hydro") and PG&E Energy Trading ("PG&E"), each having contracted for 52.5 MMcfd of firm transportation capacity from the SCP interconnect with TransCanada PipeLines Limited ("TCPL") at Yahk to the Huntingdon delivery point on the Westcoast Energy Inc. ("Westcoast") system, for demand charges of $3.6 million per year each, or an aggregate of $7.2 million. In addition, the Order also accepted for filing Peaking Gas Purchase Agreements with BC Hydro and PG&E. The Peaking Gas Purchase Agreements provided Terasen Gas access to an equivalent volume of peaking gas at Huntingdon for up to 15 days per year. The primary term of 10 years would expire on November 1, 2010, however the agreements allowed for unilateral shipper renewal rights for up to an additional 10 years. As part of these arrangements BC Hydro also negotiated a put option ("Put Option") with Terasen Inc. (then BC Gas Inc.), that allowed BC Hydro the provision to assign the Firm Tendered Transportation Service Agreement and the Peaking Gas Purchase Agreement to Terasen Inc. for the remaining period in the primary term upon 13.5 months notice.

3. During the winter of 2000/01, as the North American energy markets went through significant price increases and volatility, in response to strong economic growth and increased energy demand. In the Pacific Northwest region, the unprecedented growth was compounded by insufficient pipeline capacity. As a result, the capacity constrained Sumas/Huntingdon market area experienced extreme volatility and historically high price increases. In response to the unprecedented increase in demand and value for regional pipeline capacity, Terasen Gas began developing the IPC project as a solution to the constrained market hub at Huntingdon, BC/Sumas, Washington. By connecting back to the Alberta AECO supply hub, IPC also presented benefits to Terasen Gas and other regional participants by providing diversity and security of supply. In May 2001, Terasen Gas held an Open Season for capacity on the IPC. Northwest Natural Gas Company ("NWN"), who had been an active supporter of IPC, responded by making a binding commitment to contract for IPC capacity.

4. On December 5 2002, the Company submitted an application to the Commission (the "2002 Application") requesting approval of a set of transactions that were designed to preserve the value of the SCP capacity contracted to PG&E, in reaction to the Company's concerns relating to financial difficulties that PG&E was experiencing. The transactions included terminating the PG&E agreements effective January 2003, resulting in 52.5 MMcfd of SCP capacity reverting to the Company as well as PG&E agreeing to assign an equivalent amount of TCPL capacity to the Company. 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 of TCPL capacity. This transaction met NWN's request for service during the IPC open season and NWN was subsequently released from any obligation with respect to the IPC capacity it had committed to under that process. As part of termination of the PG&E agreements, the Company agreed to make certain payments to PG&E over the period through 2019. The net effect of these transactions was to significantly increase the mitigating revenue that Terasen Gas expected to realize for the PG&E capacity by $2.5 to $5.2 million per year.

5. As the SCP (and TCPL) capacity related to PG&E was 52.5 MMcfd and the NWN agreement accounted for 46.5 MMcfd, this resulted in approximately 6 MMcfd of SCP and TCPL residual capacity left to the Company. During the January 1, 2003 through October 31, 2004 period ("Interim Period") Terasen Gas would utilize the released capacity as part of its portfolio of Midstream resources. Subsequent to the Interim Period, the Company suggested it would likely continue to use the residual SCP and TCPL capacity as part of its Midstream resource portfolio.

6. Also included in the 2002 Application were two further requests. 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. Second, the Company requested approval to recover the development and marketing expenditures Terasen Gas had spent on the IPC project, in the event the project does not proceed or is indefinitely deferred. Terasen Gas indicated its intent to begin recovery of IPC costs in 2006 if the project had not proceeded by that time, and further indicated that by meeting NWN's IPC commitment with existing SCP capacity previously held by PG&E, the project was more likely to be deferred.

7. The Commission responded to the 2002 Application in its Letter No. L-48-02, dated December 5, 2002, and indicated it was prepared to approve the proposals related to PG&E and NWN, including the use of the SCP capacity and the proposed use of the TCPL capacity. Further, the Commission ordered that for the Interim Period any variances from the forecast amount of revenue from the PG&E SCP capacity and related mitigation revenue should be recorded and tracked separately in a SCP third party revenue mitigation account, of which the timing and recovery of the balance would be determined by the Commission at a future date. The NWN agreement was approved as Tariff Supplement I-6, to be effective November 1, 2004, by the Commission in Order No. G-9-03, dated February 13, 2003. The same Commission Order also approved the cancellation of the PG&E SCP and Peaking agreements, effective January 1, 2003.

8. Commission Letter No. L-48-02 also set out its position respecting the Company's requests with regard to the BC Hydro Put Option and recovery of the IPC Project's development and marketing expenditures. The Commission stated that in the event BC Hydro exercised its Put Option, the Commission was prepared to approve the return of BC Hydro SCP capacity provided Terasen Gas is reimbursed for any net costs or losses that result. In addition, the Commission noted "that 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 for BC Gas (now Terasen Gas) customers based on the value that IPC expenditures have had for customers, including the contribution to the present arrangement with NWN".

9. Effective January 1, 2003, the transportation and peaking gas agreements with PG&E were terminated and the released capacity was used to provide firm transportation service to NWN beginning in November 2004.

10. In September 2004, BC Hydro notified the Company and Terasen Inc. that it was exercising its Put Option to assign the transportation and peaking service agreements to Terasen Inc. with an effective date of November 1, 2005. Terasen Gas has evaluated the benefit to its portfolio of midstream resources on the basis that it assumes this SCP capacity on November 1, 2005, and has concluded that it would result in net savings, or benefit, for customers in the range of approximately of $2 to 3 million per annum, relative to the existing portfolio.

11. In addition, Terasen Gas recognises 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.

12. This Application seeks approval of several transactions related to the events described above. The Company submits that these transactions should be considered, to the extent possible as a whole, in consideration of the linkages and interdependencies of each.

13. This Application 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. Further, Terasen Gas seeks approval to continue to use the 6 MMcfd residual SCP capacity as part of its Midstream Portfolio of resources. This is described in detail in Section 1 of this Application.

14. This Application seeks approval for Terasen Gas and Terasen Inc. to terminate the transportation service and peaking gas agreements currently held by BC Hydro on the effective date (November 1, 2005) of the assignment by BC Hydro to Terasen Inc. This is described in detail in Section 2 of this Application.

15. This Application seeks approval for the Company to include the 52.5 MMcfd SCP capacity (currently held by BC Hydro) in its Midstream resource portfolio, effective November 1, 2005 and make adjustments to its other peaking and transmission capacity resources in a manner that optimizes the portfolio. This is described in detail in Section 2 of this Application.

16. This Application seeks approval of an annual allocation of $ 3.6 million (based on monthly instalments) to be debited against the Midstream Cost Reconciliation Account ("MCRA"), with an equal and offsetting allocation to be credited to the delivery margin revenue account for the remainder of the primary term (i.e. ending November 1, 2010), to be effective November 1, 2005. This is described in detail in Section 2 of this Application.

17. This Application seeks recovery of IPC development costs, including a provision for AFUDC, which are currently included in a non-utility deferral account, effective January 1, 2006. This is described in detail in Section 3 of this Application.

18. Terasen Gas suggests that this Application be reviewed through a written public process.

All of which is respectfully submitted.

Dated at Vancouver, British Columbia, this 1st day of June, 2005.

TERASEN GAS INC.

Original signed by Tom Loski

For: Scott A. Thomson
Vice President, Finance and Regulatory Affairs

All questions or comments pertaining to this Application should be directed to:

Mr. Tom Loski
Director, Regulatory Affairs
Terasen Gas Inc.
Regulatory.Affairs@terasengas.com

Introduction

This Application is divided into 4 sections. The first is a review of the PG&E and NWN agreements. The second is a discussion of the BC Hydro Put Option. The third is related to the IPC project. The fourth section is a conclusion and summary of the rate impacts of the various transactions, some of which have already been approved and others that have been proposed in this Application.

1. PG&E Energy Trading and Northwest Natural Gas Company

Terasen Gas submitted its 2002 Application to the Commission for approval to enter into a set of transactions that effectively allowed the utility to terminate the transportation and peaking service agreements with PG&E and to use the released SCP capacity to provide long term firm transportation to NWN. These arrangements came about as a result of the following events and activities:

- The Company was developing the IPC project as a solution to the constrained market place at Sumas/Huntingdon market area that had resulted in significant price increases and volatility during the winter 2000/01. The IPC project is discussed in detail under Section 3 of this Application.

- NWN 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.

- 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.

The proposed transactions included terminating the PG&E agreements effective January 2003, resulting in 52.5 MMcfd of SCP capacity reverting back to the Company as well as PG&E agreeing to assign an equivalent amount of TCPL capacity to the Company. 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. These transactions result in approximately 6 MMcfd of SCP and TCPL residual capacity left to the Company. During the Interim Period Terasen Gas would utilize the released capacity as part of its portfolio of Midstream resources. Subsequent to the Interim Period, the Company indicated it would continue to use the residual SCP and TCPL capacity as part of its Midstream resource portfolio. As part of termination of the PG&E agreements, the Company agreed to make certain payments to PG&E over the period through 2019. The net effect of these transactions was to significantly increase the mitigating revenue that Terasen Gas expected to realize for the PG&E capacity by \$2.5 to \$5.2 million per year.

As part of the 2002 Application the Company also asked for approval of certain items related to the BC Hydro SCP capacity and the IPC project, which are discussed in detail under Section 2 and Section 3 respectively, of this Application.

In response to the 2002 Application, the Commission in its Letter No. L-48-02, indicated it was prepared to approve the proposals related to PG&E and NWN, including and the use of the SCP capacity and the proposed use of the TCPL capacity. As a result, the SCP agreements with PG&E were terminated, and Terasen Gas and NWN entered for 16 year firm transportation agreement for 46.5 mmcfd of the released PG&E capacity beginning in November, 2004. The NWN agreement was approved as Tariff Supplement I-6, to be effective November 1, 2004, by the Commission in Order No. G-9-03, dated February 13, 2003. The same Commission Order also approved the cancellation of the PG&E SCP and Peaking agreements, effective January 1, 2003. The payment schedule related to the PG&E and the Company is set out in Attachment 1, of this Application.

The Commission in its Letter No. L-48-02 also directed that Terasen Gas was to assume PG&E's SCP capacity for the Interim Period. The Commission stipulated 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. The Company was also directed to track such losses and revenue in a separate category within the mitigation account and stated that a future date would determine the timing and method by which balances in the account are to be flowed to customers. Terasen Gas accomplished this by debiting a rate base deferral account for $3.6 million in 2003 and $3.0 million in 2004, or a total of $6.6 million for the Interim Period. These entries were offset by a corresponding credit to delivery margin revenue. This transaction effectively preserved the value of the transportation revenue related to the PG&E TSA in the delivery margin revenue account, thereby not resulting in any impact to customers with respect to delivery margin rates. 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.

TGVI also assumed PG&E's upstream TCPL capacity (53.5 mmcfd) for the period January 2002 to November 2004. Costs and mitigation revenue related to the TCPL capacity were recorded in the MCRA. Additionally, Terasen Gas assumed the 6 mmcfd of residual SCP and TCPL capacity not contracted by NWN as part of its portfolio of Midstream resources.

As described above, 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.

As part of the Company's determination of its 2005 revenue requirement, as set out in its Annual Review submission, the SCP deferral account was included with an amortization of approximately $503,000. The annual revenue requirement was approved by the Commission in its Order No. G-112-04, dated December 15, 2004. The company expects the balance in the deferral account, on an after tax basis to be approximately $2.644 million at December 31, 2005. A continuity schedule of the deferral account is included as Attachment 2.

The Company seeks approval to record the PG&E termination payments for the period November 1, 2004 through December 31, 2005 in the deferral account as set out above and to recover the balance in the deferral account in a manner consistent with that approved for 2005. This Application also seeks approval of the recovery of the PG&E termination payments as a debit to delivery margin revenue, as per the approved schedule of payments (per Attachment 1), commencing January 1, 2006.

2. BC Hydro Southern Crossing Capacity and Put Option

Under the SCP TSA, BC Hydro had contracted for 52.5 MMcfd of firm transportation capacity with a demand charge of $3.6 million per year. In addition, BC Hydro provided a peaking service giving Terasen Gas access to an equivalent volume of peaking gas at Huntingdon for up to 15 days per year. The primary term of 10 years expires on November 1, 2010, however the agreements allowed for unilateral shipper renewal rights for up to an additional 10 years. In addition, the agreement allowed BC Hydro priority to access excess daily unutilized SCP capacity for a nominal fuel charge and priority rights to expansion capacity on SCP, which would include future priority rights to contract for IPC. As part of these arrangements 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 in the primary term upon 13.5 months notice.

In the 2002 Application, Terasen Gas requested confirmation that if BC Hydro exercised its option to assign the SCP transportation agreement and related peaking agreement to Terasen Inc., that Terasen Gas would take assignment of those agreements from Terasen Inc. The supporting analysis showed that, based on the market prices at the time, it was expected that Terasen Gas would be able to assume the SCP capacity and make other adjustments to its resource portfolio with little or no impact to the cost of the portfolio. In addition any downside risk was more than offset by the additional revenue realized by the NWN transport arrangements.

In Letter L-48-02, the Commission noted that in the event the BC Hydro exercised its SCP put option, the Terasen Gas may have greater flexibility in managing the capacity than Terasen Inc., and that it was prepared to approve the assignment of the returned BC Hydro SCP capacity provided that Terasen Gas is reimbursed for any net costs or losses that result.

BC Hydro provided notice to Terasen Gas and Terasen Inc. on September 15, 2004, that it was exercising its Put Option to assign the transportation and peaking service agreements to Terasen Inc. with an effective date of November 1, 2005. By exercising this Put Option, BC Hydro also gives up its right to access daily unutilized SCP capacity at a variable fuel cost, priority rights to expansion capacity on SCP, and any future priority rights to contract for capacity on IPC.

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. At the same time, BC Hydro also transfers to Terasen Inc. its obligation to provide Terasen Gas the matching peaking option that is currently accounted for as part of the company’s MCRA. Terasen Inc.’s obligations under these agreements are for the period beginning November 1, 2005 to the end of the remaining primary term in SCP agreements, October 31, 2010. Subsequent to October 31, 2010, the capacity effectively reverts back to the Company.

Terasen Gas has evaluated the benefit to its Midstream portfolio of resources of the assignment of the returned BC Hydro SCP capacity beginning November 1, 2005, and has concluded that it would result in net savings in the range of approximately of $2-3 million per annum over the period to October 31, 2010.

Evaluation of the Midstream resource portfolio impacts related to the use of the SCP capacity was performed in a manner consistent with Terasen Gas’ annual evaluation of resource alternatives to meet both design peak day and annual load requirements. Terasen Gas develops its midstream resource portfolio of pipeline, storage and commodity contracts to meet the following objectives:

- To contract for cost-effective supply resources which ensure safe and reliable natural gas deliveries to meet Core customer design peak day while mitigating against upstream and downstream supply disruptions.

- To develop a portfolio resource mix that incorporates price diversity and provides contracting flexibility for both short-term and longer-term planning.

Terasen Gas submits that utilizing the BC Hydro SCP capacity as part of its portfolio of Midstream resources meets these objectives and provides for optimal benefits to customers.

The use of the BC Hydro SCP capacity as part of its Midstream resource portfolio allows Terasen Gas to optimize the use of the associated Kingsvale to Huntingdon capacity on the Westcoast system that would otherwise be reserved to match BC Hydro SCP capacity. The segmentation of T-South Long-Haul capacity on the Westcoast system has enabled Terasen Gas to turn back relatively expensive T-South Long-Haul transportation while allowing the Company on normal days to optimize the acquired SCP capacity by aligning stranded T-South Inland and Kingsvale South segments to effectively create Long-Haul capacity. As a result, 54 TJ/d of T-South long haul capacity can be released, which leads to savings for customers of approximately $8 to 9 million per year, realized as a reduction to the MCRA.

As a result of this turn back of expensive Westcoast T-South capacity from Station #2 to Huntingdon, in order to manage very cold or peak days when 100% of the Terasen Gas’ T-South Inland capacity is required to meet the Company’s demand requirements for its Interior service area (“Interior”) via Savona, Terasen Gas 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 impact of these transactions is approximately $1.1 to 1.2 million per year, which would be debited to the MCRA.

Terasen Gas 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 otherwise would move South to Malin. 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.

The de-contracting of the T-South also benefits the customers of Terasen Gas with respect to impacts related to forecast toll increases. Current market conditions have resulted in total de-contracting of 767 MMcfd of T-South pipeline capacity on Westcoast effective November, 2005 and decontracting of 200 mmcfd effective November, 2004, have caused 2005 demand charges to rise by approximately 19% above 2004 levels. The forecasted T-South Long-Haul toll for 2006, which incorporate the additional decontracting, is estimated to range from $0.38/mcf to $0.43/Mcf ($0.35/GJ to $0.40/GJ, an increase of 15%-25% over 2005 levels.

In light of recent market developments with respect to the significant levels of T-South de-contracting for the 2005/06 gas contract year, SCP transportation becomes an essential asset in shifting the supply sourcing from the Westcoast system (i.e. Station 2 and Huntingdon) to more liquid and less constrained market centres. SCP capacity provides Terasen Gas access to either Kingsgate or Alberta supply, and ensures firm delivery directly to the Interior or to the Lower Mainland via Westcoast's Kingsvale South transport. The addition of SCP capacity into the Midstream resource portfolio provides greater security of supply, increased flexibility and overall cost reduction for Terasen Gas customers.

Currently the revenue the Company receives from BC Hydro with respect to the TSA is recorded as delivery margin revenue, which, in part, offsets the cost of service related to the SCP. The cancellation of the BC Hydro TSA would result in a reduction of the delivery margin revenue of $3.6 million per year. As a result, Terasen Gas submits it is appropriate to address this revenue shortfall by allocating a portion of the net MCRA savings to delivery margin revenue equal to the $3.6 million. This treatment is consistent with the treatment of the revenue shortfall for the Interim Period, resulting from the termination of the PG&E agreement. Terasen Gas submits this is a fair and appropriate allocation between the MCRA and the delivery margin revenue.

Table 3 in Attachments 3a and 3b illustrate the savings, as described above, to the customers of Terasen Gas as a result of the optimization of the Midstream resource portfolio regarding the released BC Hydro contracts, and provides a sensitivity regarding the forecast of expected T-South Long Haul tolls. The results show that the assignment of the returned SCP capacity and the subsequent optimization of Terasen Gas' Midstream resource portfolio will result in savings in the range of approximately $2-3 million/year after taking into account the termination of the $3.6 million in demand charges from BC Hydro. The net present value of these savings with a 6.02% discount rate to the period ending October 31, 2010 is approximately $13-15 million.

This Application seeks approval for Terasen Gas and Terasen Inc. to terminate the transportation service and peaking gas agreements currently held by BC Hydro on the effective date (November 1, 2005) of the assignment by BC Hydro to Terasen Inc. Additionally the Company is seeking approval for the Company to include the 52.5 MMcfd SCP capacity (currently held by BC Hydro) in its Midstream resource portfolio, effective November 1, 2005 and make adjustments to its other peaking and transmission capacity resources in a manner that optimizes the portfolio. This Application seeks approval of an annual allocation of $ 3.6 million (based on monthly instalments) to be debited against the MCRA, with an equal and offsetting allocation to be credited to the delivery margin revenue account for the remainder of the primary term (i.e. ending November 1, 2010), to be effective November 1, 2005.

3. Inland Pacific Connector

During the winter of 2000/01, as the North American energy markets went through significant volatility, the capacity constrained Sumas/Huntingdon market experienced unprecedented price increases. As a solution to the unparalleled increase in demand and value for regional pipeline capacity, Terasen Gas began developing the IPC project as a solution to the constrained market place at Sumas/Huntingdon. By connecting back to the Alberta AECO supply hub, IPC also presented benefits to Terasen Gas and other regional participants by providing diversity and security of supply.

The IPC proposal involves the 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 project was expected to cost $495 million and would add 300-350 mmcfd of additional pipe capacity to the region. A less costly alternative to connect to the Westcoast system at Hope was also assessed, which would allow the project economics to support a smaller 200 mmcfd expansion based on a $300 million project.

In May of 2001 the Company conducted an Open Season for capacity on the IPC. NWN had been an active supporter of IPC, and made a binding commitment to contract for IPC capacity during the IPC Open Season.

An Application to the Environmental Assessment Office (“EAO”) for a Project Approval Certificate was filed on February 19, 2002, and an extensive consultation process followed over the next 12-13 months. At this time, Terasen Gas is in receipt of a Section 11 Order, and the Supplemental Information Specifications from the EAO office that successfully completes the first phase of the Environmental Review and sets out the process for obtaining the final approvals for IPC. The project documentation associated with the EAO process can be found by selecting Inland Pacific Connector on from the list of projects at www.eao.gov.bc.ca.

In the first quarter of 2003, development activities on IPC were largely suspended due to the changing market conditions causing in the deferral and /or cancellation of many planned power generation projects and reduction in industrial load in the region. This substantial shift in the demand forecast also resulted in the cancellation or downsizing of other pipeline projects proposals by Westcoast, TCPL, and PG&E Gas Transmission-Northwest (now owned by TCPL). For example, Westcoast’s 2003 T-South 200 MMcfd expansion project to Huntingdon was fully subscribed, however the actual physical expansion that was put in place was reduced to 84 mmcfd to Huntingdon through optimization of turned back capacity and the Terasen Gas arrangements with respect to Kingsvale South capacity.

In the 2002 Application, Terasen Gas requested Commission approval for recovery of the IPC marketing and development expenses in the event the IPC project did not proceed by 2006. Terasen Gas believes its customers have realized long term direct and indirect benefits as a result of the marketing and development efforts carried out on IPC. More specifically, 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. Terasen Gas also believes that the development of a legitimate pipeline alternative to serve the region has resulted in better positioning for the Terasen Gas and other regional local distribution companies in its dealings with Westcoast Energy relative to the producer community. 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.

Terasen Gas had been pursuing reasonable toll levels for Kingsvale South capacity since the initiation of SCP and made submissions to the National Energy Board (“NEB”) in 1998. In response to Westcoast’s argument that segmented tolls would result in stranded T-South capacity upstream from Kingsvale, the NEB initially ruled in its March 1999 Decision RH-2-98 that the full T-South long haul for Kingsvale South movements would apply until such time Westcoast elected to do an expansion of its system. In April 2001, Westcoast initiated an open season for a 2003 expansion project for 200 mmcfd of capacity, which was to compete with the proposed IPC project to service the Huntingdon/Sumas market area. Prior to the proceedings before the NEB with respect to this expansion project, Terasen Gas negotiated an agreement with Westcoast that allowed optimization of existing T-South capacity utilizing the SCP throughput capacity to Kingsvale. This proposal resulted in a lower cost option for a smaller scale expansion on the Westcoast system, benefiting all T-South customers. The NEB approved this lower cost, smaller expansion, as well as the agreement between the two parties that set out separate Kingsvale South tolls in its decision GH-1-2002, dated January, 2003. As a result, Terasen Gas was able to optimize its own holdings of T-South Long Haul, Interior and Kingsvale South capacity, which in total resulted in savings of approximately $5.5 million per year at that time. The details of the savings had been set out on a confidential basis in a submission to the Commission dated September 25, 2002.

The segmentation of the T-South capacity also now provides Terasen Gas the capability to optimize the SCP capacity that had previously been held by BC Hydro and provide further savings to its customers by reducing the cost of its Midstream resource portfolio as described in the previous section. Terasen Gas submits that these realized savings, to the benefit of all Terasen Gas customers, as well as savings to other Westcoast shippers from the reduction in the Westcoast tolls, would have been more difficult to attain without the development efforts of the IPC project.

As at the first quarter of 2003, the direct expenses related to the development of IPC total $5.4 million. The majority of the development activities and expenses were related to marketing, stakeholder consultation, routing, preliminary engineering design and the environmental, land use and socio-economic assessment of the project. At that point in time, development activities on IPC were largely suspended due to the changing market conditions causing the deferral and /or cancellation of many planned power generation projects and also resulting in a deferral of many pipeline project proposals. Costs related to the development of IPC have been accrued in a separate account and to date have not been included in Terasen Gas' revenue requirements. A breakdown of the IPC development expenses is included as Attachment 4.

In Letter L-48-02, the Commission stated that if "the IPC project is substantially deferred, that 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". Terasen Gas recognises that current market conditions are not expected to support new regional capacity in the near term and has indefinitely deferred further development of the IPC project. Terasen Gas therefore respectfully requests the Commission now approve the recovery of IPC development costs.

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. The total capital costs for the installation of SCP project were well under the allowed expenditure cap to the extent that the addition of the IPC development costs into the SCP rate base would not result in the total exceeding the cap, as demonstrated in the table below.

SCP Project Costs – Gas Plant in Service	$394,872k
IPC Development Costs	5,409k
IPC AFUDC	392k
Total IPC	5,801k
Total SCP / IPC Combined	$400,673k
Total SCP Capped Capital Expenditure C-11-99, Appendix A, Page 2	$414,000k

Typically, when prudently incurred project development costs of this nature are placed into rate base, an Allowance for Funds Used During Construction ("AFUDC") is calculated and added to the development costs on a monthly basis from the commencement of the development efforts. If this were the case here, this would normally result in AFUDC being calculated on the balances going back to the commencement of expenditures in March 2001. However, for IPC, since the project has not yet been completed, the Company proposes that it is reasonable to calculate AFUDC commencing November 1, 2004, the date the NWN TSA came into effect. In this way, the timing of the value derived from the NWN TSA is matched with the determination of AFUDC. The AFUDC amount calculated from November 1, 2004 through December 31, 2005 is $392,000 (see Attachment 5). This amount has been added to the $5.4 million of development costs for a total addition to rate base of approximately $5.8 million. This will have the impact of increasing the delivery margin associated with SCP in 2006 by approximately $659,000 which declines over time. This cost is more than offset by the net benefits to the delivery margin realized by the NWN transportation arrangements. The average cost of service impact of including IPC development costs is approximately $0.003 per GJ.

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.

4. SUMMARY OF FINANCIAL IMPACTS

The arrangements that are discussed in this submission result in significant net benefits to Terasen Gas customers over and above the value that was initially expected to result from Southern Crossing transportation capacity. The financial impacts of these arrangements are discussed in this section and deal which each of the transactions discussed in the previous sections as follows:

	Delivery Margin	Midstream Portfolio of resources
1. Termination of PG&E Agreements and subsequent arrangements	• Increased demand charges from NWN • Payment of PG&E termination payments • Mitigation of SCP Capacity in Jan03 – Oct04 period	• Replacement of the peaking gas arrangement • Assumption of 6 mmcfd of residual SCP capacity
2. Turnback of BC Hydro SCP Capacity	• Replacement of Demand Charges by Midsteam Portfolio	• Inclusion of 52.5 mmcfd of SCP capacity • SCP demand charges paid to Delivery Margin • Optimisation of Westcoast Capacity • Replacement of peaking gas arrangements
3. Recovery of IPC Development Costs	• Addition of the IPC development costs to SCP rate base	

The overall financial impacts to the Delivery Margin and Midstream Portfolio of resources are summarized in Attachment 3a over the period November 2004 to October 2010, matching the remaining period in the primary term of the original SCP agreements beginning when NWN arrangements came into effect. The net present value of the arrangements is calculated using both Terasen Gas' after tax cost of capital (6.02%). The present values are also provided using a 10% discount rate.

- Table 1 illustrates the baseline SCP third party mitigating revenues scenario matching the third party annual revenues of $7.2 million (Line 5) from BC Hydro and PG&E expected at the time the SCP CPCN was approved.

- Table 2 summarises the impact of the various arrangements on the Delivery Margin account resulting in an increase in the mitigating revenue from $7.2 million to $9.8 million (levelized) for a net benefit of $2.6 million (Line 34) per annum over remaining period in the primary term. The net present value of this net benefit is calculated to be $12.8 million (Line 36).

- Table 3 summarise the net benefit that would accrue to the MCRA as a result of the optimisation of the Midstream Portfolio of resources that result from the inclusion of the 6 mmcfd residual PG&E SCP capacity and the 52.5 mmcfd of the SCP capacity BC Hydro Capacity, replacement of the peaking gas arrangements initially provided by both BC Hydro and PG&E, and optimization of the Terasen Gas' Westcoast capacity. The value of the released Westcoast capacity is based on an avoided Westcoast T-South toll of $0.35 per GJ, the lower of the forecast range of $0.35 to $0.40 per GJ for Westcoast tolls discussed in Section 2. The results show that annual savings to the Midstream portfolio increasing to approximately $3.6 million (Line 54) starting in November 2005 when Terasen Gas assumes the SCP capacity currently held by BC Hydro. The net present value of the net benefit is calculated to be $14.7 million (Line 56). If the actual avoided T-South toll is $0.40, the annual benefit would increase by approximately $1 million per year increasing the present value to $18.5 million (Attachment 3b, Table 3, Line 56).

- Table 4 summarises the combined net annual benefit of the arrangements to Terasen Gas' overall revenue requirement over and above the expected value of the initial third transport agreements with PG&E and BC Hydro. On a levelized basis, the annual net benefit to customers over the period is estimated to be $5.6 million (Line 63) assuming avoided T-South toll of $0.35 per mcf. The net present value of this net benefit over the period ending October 2010 is determined to be $27.5 million (Line 64).

Nov 2004 to Oct 2010 Net Benefit (Millions)	$ Annual Svgs (Levelized)	PV @ 6.02%	PV @ 10%
Impact to Delivery Margin	$ 2.6	$ 12.8	$ 11.5
Impact to Midstream Portfolio	3.0	14.7	12.9
Total	$ 5.6	$ 27.5	$ 24.4

Attachment 3b, repeats the calculations described above, however in determining the impact to the Midstream Portfolio of resources, it was assumed that the avoided Westcoast T-South toll is $0.40 per GJ. As is shown in Table 4 of Attachment 3b, this increases the annual expected benefit to approximately $6.4 million and the net present value of the net benefit to $31.3 million.

This analysis summarised in the table above has been provided for the remaining period of the primary term of the original SCP third party transport agreements, which would have expired on November 2010. Although the initial PG&E and BC Hydro agreements included the right to renew the agreement for a further ten years, the BC Hydro Put Option would not have extended beyond the end of the primary term. If PG&E and BC Hydro had not renewed the agreements, the capacity would have reverted to Terasen Gas. At that time, Terasen Gas would assess the market value of the capacity and make decisions on how capacity would be best used as part of its own portfolio versus selling the capacity to third parties in long or short term arrangements in order to reduce costs to customers. Terasen Gas continues to hold that option with the returned BC Hydro capacity over the long term. Given the present market conditions, however, Terasen Gas believes that the proposed transactions associated with retaining the BC Hydro SCP capacity as part of the Midstream Portfolio of resources currently offers the best value to customers.

NWN transportation service continues to 2020 providing long term certainty on third party revenues on that portion of the SCP capacity. As discussed in the 2002 Application, after 2010, the revenue expected from the NWN demand charges, as adjusted by the PG&E termination payments, increases by $2.4 million to approximately $9 million per year. The present value of this revenue over the period November 2010 to 2020 is approximately $45.6 million ($31.2 using a 10% discount rate).

The proposed recovery mechanism of the IPC development costs discussed in Section 3 also extends beyond the 2010 period. The present value of the incremental revenue requirement associated with the addition of these costs to rate base up to 2020 is approximately $5.4 million of which $2.5 million has already been accounted for in Attachment 3a. This cost is significantly more than offset by the net overall benefits to 2010, and by the NWN arrangements that continue on through to 2020. In addition, TGVI believes that to a large part, these benefits has been a direct outcome of the NWN transportation arrangement realized as a result of the development of the IPC project and the alternative Midstream resource portfolio arrangements facilitated by segmentation of T-South capacity on the Westcoast system.

5. Conclusion

This Application seeks approval of several transactions as described in the previous 3 sections above and summarized in Attachment 3a. Terasen Gas submits that these transactions should be considered, to the extent possible as a whole, in consideration of the linkages and interdependencies of each, specifically that the development of the IPC project provided significant leverage in order to achieve the significant savings resulting from the other transactions.

List of Attachments

Attachment 1 – PG&E Payment Schedule

Attachment 2 – Deferral Account Continuity Schedule

Attachment 3 – SCP Savings

Attachment 4 – Detailed ICP Costs

Attachment 5 – IPC AFUDC Calculation

ATTACHMENT 1

Master Termination and Assignment Agreement Schedule "A"
Annual Settlement Payments from November 01, 2004 to October 31, 2020

Contract Year	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Annual Settlement Amount	$825	$825	$825	$825	$825	$825

Contract Year	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Annual Settlement Amount	$145	$145	$145	$145	$145	$145	$145	$145	$145

ATTACHMENT 2

TERASEN GAS INC.
SCP DEFERRAL ACCOUNT CONTINUITY SCHEDULE

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	$ -
	(2,715,123)							

ATTACHMENT 3
Financial Impacts

Attachment 3a

ATTACHMENT 3a

Summary of Financial Impacts (2004/05 onwards)

Costs and Benefits represented as Gas Year

	Year	1	2	3	4	5	6
	Contract Year	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
1	**Table 1. BASELINE - Mitigating Revenues Per SCP CPCN Application**						
2	PG&E Demand Charges	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
3	BC Hydro Annual Demand Charges	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
4	SCP Mitigation Revenue	$0	$0	$0	$0	$0	$0
5	Total SCP Firm Transport Revenues **(A)**	$7,200	$7,200	$7,200	$7,200	$7,200	$7,200
6							
7							
8	**Table 2. Adjusted SCP Mitigating Revenues per NWN and Terasen Arrangements**						
12							
13	**Firm Transport Revenues related to PG&E and NW Natural Arrangements**						
14	NWN Annual Demand Charges	$7,298	$7,298	$7,298	$7,298	$7,298	$7,298
15	PG&E Termination Payment			($825)	($825)	($825)	($825)
16	PG&EEC Termination Payments 2004-2005		($131)	($158)	($158)	($158)	($26)
17	Net NW Natural Revenue **(X)**	$7,298	$7,167	$6,315	$6,315	$6,315	$6,447
18							
19	**Firm Transport Revenues related to BC Hydro SCP Capacity Transferred to TGI**						
20	BC Hydro Annual Demand Charges	$3,600	$0	$0	$0	$0	$0
21	TGI Midstream Annual Allocation	$0	$3,600	$3,600	$3,600	$3,600	$3,600
22	Net BCH/TGI Revenue **(Y)**	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
23							
24	**Adjusted Mitigating Revenue to Delivery Margin Revenue**						
25	Net Transport Revenues **(X+Y)**	$10,898	$10,767	$9,915	$9,915	$9,915	$10,047
26	Incremental Revenue Requirement Related to IPC Development Costs	$0	($549)	($600)	($580)	($573)	($566)
27	Adjusted Mitigating Revenue **(B)**	$10,898	$10,218	$9,315	$9,336	$9,343	$9,481
28	Levelised Adjusted Mitigating Revenue	$9,814					
29							
30	**Comparison to Baseline Mitigating Revenue**						
31	Baseline Mitigating Revenue (A)	-$7,200	-$7,200	-$7,200	-$7,200	-$7,200	-$7,200
32	Adjusted Mitigating Revenue (B)	$10,898	$10,218	$9,315	$9,336	$9,343	$9,481
33	Net Benefit (Cost) to Delivery Margin Account	$3,698	$3,018	$2,115	$2,136	$2,143	$2,281
34	Levelised Net Benefit	$2,614					
35	**Present Value of Net Benefit**	To 31 Oct 2010	To 31 Oct 2020				
36	NPV @ 6.02%	$12,844	$12,844				
37	NPV @ 10%	$11,522	$11,522				

ATTACHMENT 3a

Summary of Financial Impacts (2004/05 onwards)

Costs and Benefits represented as Gas Year

Year	1	2	3	4	5	6
Contract Year	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10

Table 3. Impact to Midstream Portfolio (Westcoast T-South = $0.35)

Termination of PG&E Agreements						
PG&E Peaking Arrangement Adjustment	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318
Residual TCPL Capacity after mitigation	($186)	($186)	($186)	($186)	($186)	($186)
Net Benefit (Cost) of PG&E Arrangement **(C)**	$1,131	$1,131	$1,131	$1,131	$1,131	$1,131
Return of BC Hydro SCP Capacity ((Westcoast T-South = $0.35)						
Midstream SCP Allocation	0	($3,600)	($3,600)	($3,600)	($3,600)	($3,600)
Release of Westcoast Capacity (T-South = $0.35)	0	$6,734	$6,899	$6,899	$6,899	$6,899
Huntingdon Downstream Resources	$0	($1,224)	($1,168)	($1,205)	($1,293)	($1,291)
Kingsgate Peaking Arrangement	$0	$261	$275	$277	$279	$279
Net Benefit (Cost) of BCH Capacity **(D)**	$0	$2,170	$2,406	$2,371	$2,284	$2,287
Net Benefit (Cost) to Midstream Portfolio						
Net Benefit (Cost) **(C+D)**	$1,131	$3,302	$3,537	$3,502	$3,416	$3,418

Present Value of Net Benefit	To 31 Oct 2010	To 31 Oct 2020
NPV @ 6.02%	$14,701	$14,701
NPV @ 10%	$12,857	$12,857

Table 4. Overall Financial Impact

Net Benefit (Cost) to Delivery Margin Account	$3,698	$3,018	$2,115	$2,136	$2,143	$2,281
Net Benefit (Cost) to Midstream Portfolio	$1,131	$3,302	$3,537	$3,502	$3,416	$3,418
Net Financial Benefit (Cost)	$4,830	$6,320	$5,652	$5,638	$5,558	$5,699
Levelised Net Financial Impact	$5,605					

Present Value	To 31 Oct 2010	To 31 Oct 2020
NPV @ 6.02%	$27,546	$27,546
NPV @ 10%	$24,379	$24,379

Attachment 3b

ATTACHMENT 3b

Summary of Financial Impacts (2004/05 onwards)

Costs and Benefits represented as Gas Year

	Year	1	2	3	4	5	6
	Contract Year	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
1	**Table 1. BASELINE - Mitigating Revenues Per SCP CPCN Application**						
2	PG&E Demand Charges	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
3	BC Hydro Annual Demand Charges	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
4	SCP Mitigation Revenue	$0	$0	$0	$0	$0	$0
5	Total SCP Firm Transport Revenues **(A)**	$7,200	$7,200	$7,200	$7,200	$7,200	$7,200
6							
7							
8	**Table 2. Adjusted SCP Mitigating Revenues per NWN and Terasen Arrangements**						
12							
13	**Firm Transport Revenues related to PG&E and NW Natural Arrangements**						
14	NWN Annual Demand Charges	$7,298	$7,298	$7,298	$7,298	$7,298	$7,298
15	PG&E Termination Payment			($825)	($825)	($825)	($825)
16	PG&EEC Termination Payments 2004-2005		($131)	($158)	($158)	($158)	($26)
17	Net NW Natural Revenue **(X)**	$7,298	$7,167	$6,315	$6,315	$6,315	$6,447
18							
19	**Firm Transport Revenues related to BC Hydro SCP Capacity Transferred to TGI**						
20	BC Hydro Annual Demand Charges	$3,600	$0	$0	$0	$0	$0
21	TGI Midstream Annual Allocation	$0	$3,600	$3,600	$3,600	$3,600	$3,600
22	Net BCH/TGI Revenue **(Y)**	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
23							
24	**Adjusted Mitigating Revenue to Delivery Margin Revenue**						
25	Net Transport Revenues **(X+Y)**	$10,898	$10,767	$9,915	$9,915	$9,915	$10,047
26	Incremental Revenue Requirement Related to IPC Development Costs	$0	($549)	($600)	($580)	($573)	($566)
27	Adjusted Mitigating Revenue **(B)**	$10,898	$10,218	$9,315	$9,336	$9,343	$9,481
28	Levelised Adjusted Mitigating Revenue	$9,814					
29							
30	**Comparison to Baseline Mitigating Revenue**						
31	Baseline Mitigating Revenue (A)	-$7,200	-$7,200	-$7,200	-$7,200	-$7,200	-$7,200
32	Adjusted Mitigating Revenue (B)	$10,898	$10,218	$9,315	$9,336	$9,343	$9,481
33	Net Benefit (Cost) to Delivery Margin Account	$3,698	$3,018	$2,115	$2,136	$2,143	$2,281
34	Levelised Net Benefit	$2,614					

35	**Present Value of Net Benefit**	To 31 Oct 2010	To 31 Oct 2020
36	NPV @ 6.02%	$12,844	$12,844
37	NPV @ 10%	$11,522	$11,522

ATTACHMENT 3b

Summary of Financial Impacts (2004/05 onwards)

Costs and Benefits represented as Gas Year

Year	1	2	3	4	5	6
Contract Year	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10

Table 3. Impact to Midstream Portfolio (Westcoast T-South = $0.35)

Termination of PG&E Agreements						
PG&E Peaking Arrangement Adjustment	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318
Residual TCPL Capacity after mitigation	($186)	($186)	($186)	($186)	($186)	($186)
Net Benefit (Cost) of PG&E Arrangement **(C)**	$1,131	$1,131	$1,131	$1,131	$1,131	$1,131
Return of BC Hydro SCP Capacity ((Westcoast T-South = $0.35)						
Midstream SCP Allocation	0	($3,600)	($3,600)	($3,600)	($3,600)	($3,600)
Release of Westcoast Capacity (T-South = $0.35)	0	$7,555	$7,884	$7,884	$7,884	$7,884
Huntingdon Downstream Resources	$0	($1,224)	($1,168)	($1,205)	($1,293)	($1,291)
Kingsgate Peaking Arrangement	$0	$261	$275	$277	$279	$279
Net Benefit (Cost) of BCH Capacity **(D)**	$0	$2,991	$3,391	$3,356	$3,270	$3,272
Net Benefit (Cost) to Midstream Portfolio						
Net Benefit (Cost) **(C+D)**	$1,131	$4,122	$4,522	$4,488	$4,401	$4,404

Present Value of Net Benefit	To 31 Oct 2010	To 31 Oct 2020
NPV @ 6.02%	$18,468	$18,468
NPV @ 10%	$16,117	$16,117

Table 4. Overall Financial Impact

Net Benefit (Cost) to Delivery Margin Account	$3,698	$3,018	$2,115	$2,136	$2,143	$2,281
Net Benefit (Cost) to Midstream Portfolio	$1,131	$4,122	$4,522	$4,488	$4,401	$4,404
Net Financial Benefit (Cost)	$4,830	$7,141	$6,638	$6,623	$6,544	$6,685
Levelised Net Financial Impact	$6,372					

Present Value	To 31 Oct 2010	To 31 Oct 2020
NPV @ 6.02%	$31,313	$31,313
NPV @ 10%	$27,639	$27,639

Description of Line Items for ATTACHMENT 3

ATTACHMENT 3a & 3b

- Line item 15 represents the cost related to the PGE termination payment of $0.825 million/year until 2010. 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.
- Line item 16 in Attachment 3a represents the PG&E termination payments for the period November 1, 2004 through December 31, 2005 that were held in the deferral account and subsequently will be recovered over a 4 year amortization period. Note again that these costs in Attachment 3a are represented in Gas Years. The derivation of the annual amortization costs is outlined in the Attachment 2 Deferral Account Continuity Schedule. Note that the costs in Attachment 2 are represented as Calendar Year costs and have been adjusted to Gas Year in Attachment 3
- Line item 20 represents the termination of the BC Hydro SCP demand charge payments to Terasen Gas as a result of BC Hydro exercising its SCP put option.
- Line item 21 represents the crediting of SCP demand charges to the delivery margin resulting from Terasen Gas incorporating the BC Hydro SCP capacity into its Midstream portfolio.
- Line item 26 is the recovery of the IPC development costs including AFUDC and as provided in Attachment 4. Again these costs have been adjusted to represent Gas Year costs.
- Line item 42, PGE Peaking Arrangement Adjustment, line item 39 in Attachment 3a represents the net savings of $1.3 million, fixed costs plus variable savings, related to the acquisition of a Mist storage contract in lieu of the PGE SCP peaking arrangement.
- Line item 43, Remaining PGE TCPL after mitigation, represents a net cost of approximately $0.19 million to Terasen of maintaining the estimated 6 MMcfd of TCPL capacity originally held by PGE for its matching SCP capacity.
- Line item 47, Midstream SCP Allocation, represents the incremental SCP demand charges debited to the Midstream portfolio that were originally paid by BC Hydro to Terasen prior to BC Hydro exercising its put option.
- Line item 44, Release of Westcoast Capacity savings, represents a benefit to Terasen of avoided T-South toll demand charges on 54 TJ/d of released T-South capacity. Given the uncertainty with uncontracted capacity on Westcoast, Terasen has evaluated scenarios with Westcoast avoided toll charges of $0.35/GJ (Attachment 3a) and $0.40/GJ (Attachment 3b).
- Line item 49, Huntingdon Downstream Resource, represents the net $1.1 to $1.2 million/year cost of replacing the Station 2 December through February supply (90 day supply) that flowed on the released T-South capacity required to supply peak day requirements.
- Line Item 50, Kingsgate Peaking Arrangement, represents the benefit of replacing the 56.5 TJ/d (52.5 mmcfd) BC Hydro SCP peaking deal with a Kingsgate peaking arrangement.

- Line item 51 identifies the over $2 million/year benefit to the Terasen Gas Delivery Margin Account generated by the NWN SCP arrangement in response to the termination of the PG&E arrangement, and the crediting of SCP demand charges from the Midstream Portfolio Account to cover the termination of the BC Hydro SCP demand charge payments to Terasen Gas.

- Line item 54 represents the net benefit to the Midstream Portfolio with the inclusion of an alternative peaking arrangement in lieu of the terminated PGE SCP peaking arrangement, acquiring the remaining TCPL capacity originally held by PGE for its matching SCP capacity, and alternative portfolio arrangements to manage the terminated BC Hydro SCP peaking deal.

- Line item 56 represents overall financial benefit to Terasen Gas.

ATTACHMENT 4
Inland Pacific Connector Development Costs

Project Management		**1,810,168**
1. General Project Management Includes costs incurred directly by Terasen involving management of employees and consultants and includes expenses such Risk Assessment study, travel expenses and helicopter rentals and engineering costs to create overall project cost estimate		
• Terasen Internal Labour	303,000	
• Helicopter for consultants	114,000	
• Consultants (Risk Assessment, compression)	71,000	
• Travel expense, meals, stationary, legal, phones etc	41,000	
2. Lands activity Consultant land management costs to create landowner files/data base, communicate with landowners, attend open houses and negotiate right of way routing	319,094	
3. Gas supply Consulting fees to draft TSA, precedent agreement, open season documents and provide toll design	83,835	
4. Communications Consulting and other costs to create story boards, hold Open Houses including media advertisements, publish Newsletters and media training consulting	194,417	
5. First Nations Third Party consulting costs to fund First Nations consultation capacity and fund various First Nations studies on and off reserve including third party consulting assistance to First Nations archeology and traditional use studies and right of way negotiations on reserve, for seven (7) different groups	683,264	
Environment		**1,179,765**
Includes Westland Resource Group environmental consulting costs to assist in route selection and complete preliminary environmental studies for the entire route in consultation with the design consultant, develop the environmental and restoration cost estimates and prepare the BC EAA application, attend open houses and consult with various government agencies and assist with consultation, working scoping and supervision of First Nations studies.		
• Consulting costs for initial field reconnaissance studies	942,680	
• Consulting costs to develop BC EAO application	207,305	
• Consulting assistance to manage aboriginal relations	29,778	

ATTACHMENT 4 (cont'd)
Inland Pacific Connector Development Costs

Design		**1,565,401**
Includes Integrated Pipeline Projects Limited consulting costs to select the route, develop the construction cost estimate, study terrain issues (seismicity and geotechnical stability), create preliminary Fraser River crossing designs for aerial, directional drill, bridge crossing and open cut including geotechnical coring program and cooperate with the environmental consultants, consult with various specialist consultants and attend open houses		
• Consulting costs for pipeline design, management of route selection and other specialist consultants, cost estimating, attending open houses, assisting land manager and contributing to BC EAA	708,847	
• Consulting services to locate pipeline route	603,201	
• Consulting costs related to geotechnical coring, HDD, open cut, bridge crossing preliminary designs	253,356	
Stage 2		**853,279**
Includes environmental consulting costs for detailed studies to complete stage 2 environmental assessments (BCEAA 2 stage application process), preliminary scoping work for compressor and control stations and preparation of the project deferral report.		
• General consulting costs to manage stage 2	104,973	
• Alternate Route Assessment consulting costs	32,395	
• Detailed environmental field studies	529,181	
• BC EAO Report Preparation	62,265	
• Environmental studies re: compressor stations	55,062	
• Hope to Huntingdon alternative studies	69,402	
Total Direct Costs		**5,408,613**
Afudc		**392,321**
Total Costs		**5,800,934**

Attachment 5

Account 17210 Summary of Prel. Investigation May 17,2005

P339 Inland Pacific Connector Project

	Addtions	Balance	AFUDC	AFUDC Balance	Cumulative Balance	AFUDC Rate
Mar-01	18,025.24	18,025.24	-	-	18,025.24	5.98%
Apr-01	161,686.06	179,711.30	-	-	179,711.30	5.98%
May-01	269,918.02	449,629.32	-	-	449,629.32	5.98%
Jun-01	339,112.21	788,741.53	-	-	788,741.53	5.98%
Jul-01	458,878.69	1,247,620.22	-	-	1,247,620.22	5.98%
Aug-01	393,781.92	1,641,402.14	-	-	1,641,402.14	5.98%
Sep-01	378,274.18	2,019,676.32	-	-	2,019,676.32	5.98%
Oct-01	385,722.42	2,405,398.74	-	-	2,405,398.74	5.98%
Nov-01	82,378.05	2,487,776.79	-	-	2,487,776.79	5.98%
Dec-01	294,120.17	2,781,896.96	-	-	2,781,896.96	5.98%
Jan-02	(4,629.97)	2,777,266.99	-	-	2,777,266.99	6.06%
Feb-02	107,249.24	2,884,516.23	-	-	2,884,516.23	6.06%
Mar-02	79,814.99	2,964,331.22	-	-	2,964,331.22	6.06%
Apr-02	344,598.20	3,308,929.42	-	-	3,308,929.42	6.06%
May-02	111,273.76	3,420,203.18	-	-	3,420,203.18	6.06%
Jun-02	149,260.53	3,569,463.71	-	-	3,569,463.71	6.06%
Jul-02	223,425.49	3,792,889.20	-	-	3,792,889.20	6.06%
Aug-02	233,511.48	4,026,400.68	-	-	4,026,400.68	6.06%
Sep-02	225,643.96	4,252,044.64	-	-	4,252,044.64	6.06%
Oct-02	334,420.44	4,586,465.08	-	-	4,586,465.08	6.06%
Nov-02	232,865.05	4,819,330.13	-	-	4,819,330.13	6.06%
Dec-02	301,559.14	5,120,889.27	-	-	5,120,889.27	6.06%
Jan-03	(19,581.56)	5,101,307.71	-	-	5,101,307.71	6.17%
Feb-03	58,577.51	5,159,885.22	-	-	5,159,885.22	6.17%
Mar-03	58,282.77	5,218,167.99	-	-	5,218,167.99	6.17%
Apr-03	32,651.72	5,250,819.71	-	-	5,250,819.71	6.17%
May-03	39,006.61	5,289,826.32	-	-	5,289,826.32	6.17%
Jun-03	22,539.21	5,312,365.53	-	-	5,312,365.53	6.17%
Jul-03	2,618.03	5,314,983.56	-	-	5,314,983.56	6.17%
Aug-03	2,177.82	5,317,161.38	-	-	5,317,161.38	6.17%
Sep-03	26,677.22	5,343,838.60	-	-	5,343,838.60	6.17%
Oct-03	6,719.25	5,350,557.85	-	-	5,350,557.85	6.17%
Nov-03	95.33	5,350,653.18	-	-	5,350,653.18	6.17%
Dec-03	31,291.75	5,381,944.93	-	-	5,381,944.93	6.17%
Jan-04	86.68	5,382,031.61	-	-	5,382,031.61	5.99%
Feb-04	36,798.00	5,418,829.61	-	-	5,418,829.61	5.99%
Mar-04	(3,723.91)	5,415,105.70	-	-	5,415,105.70	5.99%
Apr-04	-	5,415,105.70	-	-	5,415,105.70	5.99%
May-04	-	5,415,105.70	-	-	5,415,105.70	5.99%
Jun-04	545.10	5,415,650.80	-	-	5,415,650.80	5.99%
Jul-04	3,018.17	5,418,668.97	-	-	5,418,668.97	5.99%
Aug-04		5,418,668.97	-	-	5,418,668.97	5.99%
Sep-04		5,418,668.97	-	-	5,418,668.97	5.99%
Oct-04		5,418,668.97	-	-	5,418,668.97	5.99%
Nov-04		5,418,668.97	27,048.19	27,048.19	5,445,717.16	5.99%
Dec-04		5,418,668.97	27,183.20	54,231.39	5,472,900.36	5.99%
Jan-05	(10,058.87)	5,408,610.10	27,405.25	81,636.64	5,490,246.74	6.02%
Feb-05	-	5,408,610.10	27,542.74	109,179.38	5,517,789.48	6.02%
Mar-05	-	5,408,610.10	27,680.91	136,860.29	5,545,470.39	6.02%
Apr-05	-	5,408,610.10	27,819.78	164,680.07	5,573,290.17	6.02%
May-05	-	5,408,610.10	27,959.34	192,639.41	5,601,249.51	6.02%
Jun-05	-	5,408,610.10	28,099.60	220,739.01	5,629,349.11	6.02%
Jul-05	-	5,408,610.10	28,240.57	248,979.58	5,657,589.68	6.02%
Aug-05	-	5,408,610.10	28,382.24	277,361.82	5,685,971.92	6.02%
Sep-05	-	5,408,610.10	28,524.63	305,886.45	5,714,496.55	6.02%
Oct-05	-	5,408,610.10	28,667.72	334,554.17	5,743,164.27	6.02%
Nov-05	-	5,408,610.10	28,811.54	363,365.71	5,771,975.81	6.02%
Dec-05	-	5,408,610.10	28,956.08	392,321.79	5,800,931.89	6.02%