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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-141-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates

BEFORE: A.W.K. Anderson, Panel Chair/Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

November 26, 2009

O R D E R

WHEREAS:

A. On June 15, 2009 Terasen Gas Inc. ("Terasen Gas") filed an application for approval of interim and permanent delivery rates effective January 1, 2010 and January 1, 2011 (the "Application") pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the "Act"), representing an increase of 5.3 percent for 2010 and 4.1 percent for 2011; and

B. Terasen Gas sought other approvals in the Application, including Orders pursuant to sections 59 to 61 of the Act, approving Tariff changes effective January 1, 2010 for Compression and Refueling and Transportation Services for Natural Gas Vehicles and economic models for evaluating biogas projects and alternative energy extensions for geo-exchange, solar thermal and district energy systems to complement its core natural gas business; and

C. The interim and permanent delivery rates sought in the Application are subject to adjustment for any changes in Terasen Gas' allowed return on equity and capital structure; and

D. Terasen Gas proposed a written hearing process to address the Application but was open to a Negotiated Settlement Process ("NSP") addressing all of the issues; and

E. In accordance with Commission Order G-76-09, a Workshop was held July 6, 2009 for a review of the Application and a first Procedural Conference was held on July 15, 2009. Commission Order G-89-09 established the requirement for a second Procedural Conference, held on September 25, 2009 to address the regulatory process and preliminary timetable; and

F. At the second Procedural Conference, the Commission Panel received submissions on the principal issues arising from or related to the Application, process options for the review of the Application, location of the proceedings and other matters that would assist the Commission's efficient review of the Application. The primary issues raised were whether a separate Certificate of Public Convenience and Necessity ("CPCN") review was required for the Alternative Energy Solutions proposed in the Application and whether the regulatory process should be in the form of an oral or written hearing or NSP; and

G. The Intervenors expressed a wish to avoid a separate CPCN process for the Alternative Energy Solutions and all Intervenors supported an NSP for the review of the Application. The Intervenors submitted that, in the event that the NSP is not successful in resolving all issues, an Oral Public Hearing could be ordered by the Commission. Terasen Gas requested that, if an Oral Public Hearing is established, it be limited in scope; and

H. Terasen Gas proposed that its application for interim rate approval be deferred until the end of November 2009; and

I. By Order G-119-09, the Commission Panel established a regulatory timetable for an NSP commencing October 21, 2009. The settlement discussions concluded on November 3, 2009; and

J. On November 13, 2009, the Negotiated Settlement Agreement ("NSA"), together with the Letters of Support received from the participants in the NSP, the Letter of Comment from Commission Staff and Terasen Gas' response to the Letter of Comment ("Settlement Package"), was made public and circulated to the Commission Panel; and

K. The Settlement Package was also distributed to Registered Intervenors who did not participate in the NSP ("Other Intervenors"). The Other Intervenors were requested to provide their comments on the Settlement Package to the Commission by November 20, 2009. The Commission Panel received no comments from Other Intervenors regarding the Settlement Package; and

L. The Commission Panel having reviewed the proposed NSA and the comments related thereto and noting the support of all parties to the proposed Negotiated Settlement Agreement, in which only sections 12(a) and (b) are severable, subject to the implementation of section 12.2, considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 and 89 of the Act the Commission orders as follows:

1. The Negotiated Settlement Agreement attached as Appendix A to this Order is approved.

2. TGI is to file an amended Summary of Rates and Bill Comparison schedules based on the Negotiated Settlement Agreement.

3. The Commission will accept, subject to timely filing by TGI, amended permanent Gas Tariff Rate Schedules in accordance with the terms of this Order. TGI is to provide notice of the permanent rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, In the Province of British Columbia, this 26th day of November 2009.

BY ORDER

Original signed by:

A.W.K. Anderson
Panel Chair/Commissioner

Attachment

ERICA HAMILTON
COMMISSION SECRETARY
Commission. Secretary@bcuc.com
web site: http://www.bcuc.com

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Log No. 29797

VIA EMAIL

November 13, 2009

Registered Intervenors
(*TGI-2010-11RR-RI*)

Dear Registered Intervenors:

Re: Terasen Gas Inc.
2010-2011 Revenue Requirements Application
Negotiated Settlement

Enclosed with this letter is the proposed settlement package for Terasen Gas Inc.'s 2010-2011 Revenue Requirements Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations are requested to provide to the Commission with their comments on the settlement package by Friday, November 20, 2009. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

Y. Lapierre
for: Erica M. Hamilton

PWN/yl
Attachments
cc: Mr. Tom Loski
Chief Regulatory Officer
Terasen Gas Inc.
(Via Email: *regulatory.affairs@terasengas.com*)

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates
Negotiated Settlement Process

WHEREAS:

A. On June 15, 2009, Terasen Gas Inc. ("TGI") filed its 2010 and 2011 Revenue Requirements Application, which was supplemented by a filing on July 9, 2009 and amended by filings on August 14 and September 18, 2009 (the "Application"); and

B. Amongst other things, the Application sought:

1. An order pursuant to sections 59 to 61 of the *Utilities Commission Act* (the "Act"), approving delivery rates for all non-bypass customers effective January 1, 2010 and January 1, 2011, representing an increase of 5.3 percent for 2010 and an additional 4.1 percent for 2011, subject to changes in TGI's allowed return on equity ("ROE") and capital structure; and

2. An order pursuant to section 44.2 of the Act approving an expenditure schedule for the continuation in 2011 of TGI's residential and commercial Energy Efficiency and Conservation ("EEC") funding, as well as new EEC funding for 2010 and 2011 for interruptible industrial programs and innovative technologies; and

3. New tariff offerings and economic tests for Compression and Refuelling and Transportation Services for Natural Gas Vehicles ("NGV"), geo-exchange, solar thermal and district energy systems and a pilot program for Biogas; and

C. A complete listing of the relief sought by TGI in the Application was included in Section D (pages 513-516)[1] of the Application; and

D. In accordance with Commission Order No. G-76-09 issued on June 19, 2009, a Workshop was held on July 6, 2009 for a review of the Application, a procedural conference was held on July 15, 2009, and TGI responded to two rounds of Information Requests; and

E. In accordance with Commission Order No. G-89-09 issued on July 20, 2009, a second procedural conference was held on September 25, 2009; and

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[1] Page 516 of the Application was amended on September 18, 2009.

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F. On October 2, 2009, the Commission issued Order G-119-09 establishing a Negotiated Settlement Process ("NSP") for the Application; and

G. The Parties to the NSP were TGI, British Columbia Old Age Pensioners et al. ("BCOAPO"), Commercial Energy Consumers Association of British Columbia ("CEC"), Teck Coal Ltd. ("Teck"), and the Ministry of Energy, Mines and Petroleum Resources ("MEMPR") (collectively referred to in this Agreement as the "Parties"); and

H. At the outset of the NSP on October 21, 2009, Commission Staff provided the Parties with a document prepared by the Commission Panel titled "Issues of Particular Concern to the Commission Panel", a copy of which is appended as Appendix 1 to this Agreement; and

I. The NSP was held on October 21-23, 30, and November 3 and 4, 2009; and

J. The Parties have negotiated in good faith to achieve a compromise settlement, reflected in this Agreement, of the issues raised by the Application, and the Commission Panel document referenced in recital H above, and further consider the Agreement reached to be fair, just and reasonable; and

K. This Agreement consists of four Parts:

Part I includes general provisions;

Part II includes the items agreed to that differ from what was requested in the Application;

Part III includes the items agreed to that remain as proposed by TGI in the Application; and

Part IV includes revised financial schedules reflecting all items set out in the Agreement.

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS

PART I – GENERAL

1. <u>Agreement a Product of Compromise</u>

The Parties recognize and emphasize that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agree that any compromises resulting from this Agreement are without prejudice to the Parties' ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

2. Whole Agreement

Unless otherwise stated in this Agreement, portions of this Agreement cannot be removed or changed by the Commission without nullifying the whole Agreement.

3. TGI to Manage Business

The Parties agree that TGI will have the discretion to manage its business and determine how best to allocate the overall O&M and Capital expenditures stipulated in this Agreement.

4. Final IFRS Rate-regulated Activity Standard

The Parties acknowledge that this Agreement is predicated on the Final IFRS Rate-regulated Activity Standard permitting the financial accounting treatment contemplated in this Agreement in the manner outlined in the current Exposure Draft on Rate-regulated Activities. The Parties agree that if, in TGI's opinion, the Final IFRS Rate-regulated Activity Standard differs from the current Exposure Draft on Rate-regulated Activities so as not to permit the financial accounting treatment contemplated in this Negotiated Settlement Agreement, which among other things anticipates the recognition of regulatory assets and liabilities for external reporting purposes, then TGI is at liberty to apply to the Commission during the period of this Agreement for a determination of that issue, and to seek changes in the regulatory treatment contemplated in this Agreement to accord with the Final IFRS Rate-regulated Activity Standard, with the resulting impacts flowed through into rates commencing in 2011.

PART II – AGREED CHANGES FROM THE APPLICATION

5. Delivery Rates

The Delivery rate changes for 2010 and 2011 that would flow from this Agreement would be a decrease of 1.73 per cent in 2010 and an increase of 3.93 per cent in 2011, subject to being updated as contemplated in this Agreement. Issue No. 5 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "2010 Rate Changes – in the event that a 2010 rate reduction were to occur as a result of negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability."

Therefore, the Parties agree that this Agreement will not result in a decrease in delivery rates for 2010 and that the 2010 forecast revenue surplus will be recorded in a 2010 Revenue Surplus Deferral Account and be applied to offset any forecast increase in delivery rates in 2011. The forecast 2010 revenue surplus of $9.2 million per Schedule 1 included in Part IV of this Agreement, is recorded in the 2010 Revenue Surplus Deferral Account, which

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DATED THURSDAY, NOVEMBER 5

will be amortized in 2011 to reduce the 2011 forecast revenue deficit. The 2010 Revenue Surplus Deferral Account will be included in Rate Base.

However, the delivery rates for 2010 and 2011 will be updated to reflect changes in TGI's allowed ROE and capital structure flowing from the Commission's decision in TGI's concurrent ROE and Capital Structure Application[2], or as adjusted from time to time by the Commission. Nothing in this Agreement precludes TGI from applying to the Commission in 2010 or 2011 for changes to its allowed ROE and capital structure.

6. Service Quality Indicators

The Parties agree that TGI will report on the same SQI's as set out in the 2004-2007 PBR Agreement and the 2008-2009 extension thereof through quarterly postings on TGI's website.

7. Customer Additions Forecast

The Parties agree that TGI's net Residential customer additions forecast is revised to be 5,952 in 2010 (increase of 352 from Application[3]) and 6,166 in 2011 (increase of 316 customers from the number specified in the Application), reflecting the updated published CMHC Q3 2009 forecast, and TGI's year end 2009 number of customers has additionally been updated to be 835,862. Customer additions for the other rate classes remain unchanged from what was specified in the Application[4].

8. Use Per Customer Rates

The Parties agree that the Residential annual use per customer is revised upward from 89.7 GJ to 91.7 in 2010 and from 88.3 to 90.3 in 2011. Use per customer rates for the other rate classes remain unchanged from what was included in the Application (other than Industrial as set out in item 9).

9. Industrial Demand Forecast

The Parties agree that the industrial demand forecast is revised upwards from what was requested in the Application based on responses TGI has since received from the 2009 Industrial Survey and actual year-to-date demand. The revised industrial demand forecast includes forecast demand of 46.5 PJ and 46.5 PJ (compared to 43.4 PJ and 43.3 PJ as presented in the Application) for 2010 and 2011 respectively.

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[2] Filed jointly by the Terasen Utilities [TGI, Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.] on May 15, 2009.

[3] See Application, page 276

[4] IBID

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10. Inclusion of SCP Capacity in MCRA

The Parties agree that TGI will continue for 2010 and 2011 to include in the MCRA the $3.6 million representing the annual cost of Southern Crossing Pipeline (SCP) capacity, because the benefits and use of the SCP capacity are used by Core Market Customers (Rate Schedules 1-7).

11. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGI for 2010:

(a) TGI will reallocate from residential and commercial EEC programs an additional $1.6 million from the amount approved for 2010 in the EEC Decision[5] to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2010.

(b) EEC funding for industrial interruptible programs for 2010 will be $435,000, which is the amount requested by TGI in the Application.

(c) EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application.

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

12. EEC Funding for 2011

12.1 The Parties agree as follows in respect of the EEC funding sought by TGI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $23.075 million, which is the amount requested by TGI in the Application.

(b) TGI will reallocate from 2011 residential and commercial EEC funding ($23.075M for 2011) an additional $1.6 million (from the $0.8 million included in the Application) to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2011.

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[5] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application

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(c) EEC funding for industrial interruptible programs will be $1.875 million for 2011, which is the amount requested by TGI in the Application.

(d) EEC funding for innovative technologies will be $4.669 million for 2011, which is the amount requested by TGI in the Application.

(e) All agreed to EEC expenditures will be considered and evaluated within the existing EEC portfolio, and will be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(f) TGI will report to the Commission on industrial interruptible and innovative technology programs as part of TGI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $23.075 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGI's

EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for industrial programs or programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGI's 2010 results report to be filed in March 2011.

- Employees responsible for the programs at TGI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

12.2 The Parties agree that the Commission may sever Section 12.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 12.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $23.075 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 12.2 takes effect, the financial schedules in Part IV of this Agreement and the revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, can be filed on or before June 30, 2010. Concurrent with that report, TGI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

13. <u>Alternative Energy Solutions</u>

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

Natural Gas service taken in combination with AES will be charged under TGI's natural gas rates.

The Parties agree that the costs incurred by TGI to provide AES should not be recovered as part of natural gas service rates, and visa versa. The Parties agree that TGI's proposed New Energy Solutions Deferral Account, attracting AFUDC, is an appropriate mechanism to address allocation issues as between TGI's gas customers and TGI's AES customers. Therefore, the Parties agree that the new Energy Solutions Deferral Account will remain in effect pending a future rate design application at an unspecified future date after 2011 and will capture and record the following (plus AFUDC) to be recovered from AES customers:

(a) Direct costs associated with AES projects as outlined on pages 267-268 of the Application, including cost of design, equipment, etc. constructing and financing; and

(b) Sales and marketing O&M and other development costs will be directly charged to the deferral account by time sheets or other direct charge (estimated at $1.0 million in 2010 and $1.5 million in 2011, representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011); and

(c) An appropriate overhead allocation, which the parties have agreed will be $500,000 in each of 2010 and 2011 (representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011).

Revenues received from customers for all AES projects, which are based on contracts approved by Commission will be recorded in the AES deferral account.

The risk of non-recovery of amounts in the New Energy Solutions Deferral Account will not be borne by natural gas ratepayers. The Parties agree that any debit balance in the New Energy Solutions Deferral Account will not be recovered through natural gas rates and any credit balance will not be applied to reduce natural gas rates.

In evaluating AES projects, TGI will apply the economic test outlined in the Application. The Parties agree that the proposed GT&C (Section 12A – Alternative Energy Extensions) are acceptable. Pursuant to the *Utilities Commission Act,* within the Alternative Energy class of service, project-specific contracts with AES customers will be filed with the Commission for acceptance as a rate, at which time the Commission may review and adjust the economic test and GT&C Section 12A – Alternative Energy Extensions.

The CPCN threshold of $5 million applies to AES projects brought forward in 2010 and 2011.

The Parties agree that it is premature to address issues relating to the gas load and gas consumption profiles of AES projects that incorporate a natural gas component. Such issues are appropriately addressed in a future rate design application, once TGI has sufficient AES customers that take gas so as to provide reliable information on gas load and gas consumption profiles.

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DATED THURSDAY, NOVEMBER 5

TGI will capture costs and revenue on a project specific basis and will report on AES projects as part of the next Revenue Requirements application.

14. Natural Gas for Vehicles ("NGV")

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) NGV Rate Schedule 26 - NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

   i. Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV Refueling Service; and

   ii. the Compression Service ("CS") Test; and

   iii. NGV non-rate base deferral account.

   The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI's withdrawal of its requests regarding NGV is without prejudice to TGI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so.

15. Biogas

Issue No. 3 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Biogas – to be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost."

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The Parties agree that, upon acceptance of this Agreement by the Commission, TGI withdraws its requests in this Application related to Biogas. The Parties acknowledge that these requests are being withdrawn to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI will bring forward an application (the "Biogas Application") during the test period that will:

(a) Address the economic assessment model; and

(b) Provide Biogas rates (including green rate, transportation rate, etc.); and

(c) Provide for recovery of costs associated with providing Biogas service.

TGI may include in the Biogas Application any Biogas Projects under development at that time. TGI is, however, not precluded from applying for Commission approval in respect of individual Biogas Projects at any time, either prior to the Biogas Application or afterwards.

16. <u>CPCN Threshold</u>

Issue No. 6 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "CPCN threshold – stay at $5 million."

The Parties accordingly agree that the CPCN threshold will remain at $5 million for 2010 and 2011. TGI's Category B Capital Expenditures forecast for the forecast period will be revised to reflect this change (please see item 18 below).

17. <u>Category A Capital</u>

The Parties agree that Category A Capital will be $43.3 million for 2010 and $46.0 million for 2011, reflecting the proposed amount updated to reflect the published CMHC Q3 2009 forecast, and TGI's adjusted re-forecasted year end net customer addition numbers (as set out in item 7).

18. <u>Category B and Category C Capital</u>

As a consequence of the CPCN threshold being established at $5 million for 2010 and 2011 (see item 16 above), TGI will file CPCN applications for the Huntingdon and Kootenay Crossing projects identified in TGI's Application. The Category B Capital will consequently be reduced by $2.2 million in 2010 and $16.0 million in 2011. TGI will seek deferral treatment for 2011 of the capital costs associated with those projects at the time of filing the CPCN Applications.

The Parties agree that Category B and C Capital will be reduced by a total of $3 million in each of 2010 and 2011. For the purposes of the determination of revenue requirements with this Application, Category B Capital has been reduced by $1 million and Category C IT Capital has been reduced by $2 million.

The revised Category B Capital Expenditures, reflecting both the CPCN adjustment and the $1 million reduction in spending, are now $17.4 million in 2010 and $14.9 million in 2011.

The revised Category C Capital Expenditures, reflecting the $2 million IT Capital reduction, are now $32.8 million in 2010 and $32.7 million in 2011.

19. Gross O&M (to be recovered from gas customers)

The Parties agree that the proposed gross O&M, before shared service allocations, recoverable from gas customers for 2010 and 2011 is reduced from the amounts included in the original Application by $4.0 million in 2010 and a further $1.5 million (for a total impact of $5.5 million) in 2011. This reduction of Gross O&M will result in a reduction in the pool of costs subject to the Shared Services Agreement with TGVI and with TGW by an estimated $3.3 million in 2010 and $4.8 million in 2011. Therefore, and as discussed in Item 21, the final Gross O&M to be included in TGI's cost of service for 2010 and 2011 will be determined based on the Shared Services and Corporate Services allocations determined in the TGVI RRA.

20. Interest Expense

The Parties agree that TGI will update its assumptions around both the issuance of long-term debt and the associated interest rates. TGI has determined that Long-term Debt Series 25 will not be issued December 1, 2009 as originally forecast and is now anticipated to be issued April 1, 2010. In addition, the interest rate forecast for Long-term Debt Series 26, to be issued July 1, 2011, has been revised downwards from 6.13 per cent to 5.65 per cent.

21. Shared Services/Corporate Services Allocations

The 2010 and 2011 revenue requirements stipulated in this Agreement are based on TGI's proposed Shared Services and Corporate Services allocation for 2010 and 2011. The Parties acknowledge, however, that the final amount allocated to TGI for Shared Service and Corporate Services cannot be confirmed until the Commission determines the TGVI RRA. The Parties agree that if the amounts allocated to TGVI for Shared Services and/or Corporate Services for 2010 or 2011 changes from that agreed to in this Agreement as a result of a settlement or decision in the concurrent TGVI RRA proceeding, then the amount(s) allocated to TGI and its revenue requirements for 2010 and 2011 will be updated by a corresponding amount to ensure recovery of all of the combined Corporate Services and Shared Services costs.

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DATED THURSDAY, NOVEMBER 5

22. Depreciation Study

The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010, with the exception of:

(a) Masonry Structures, which has been updated to 40 years instead of 22.88 years; and

(b) the component of those rates that represent recovery of negative salvage (see item 23 below).

Adjusting for the Masonry Structures, negative salvage, and the impacts of capitalized overhead and capital additions changes yields total depreciation expense of $98.3 million in 2010 and $100.5 million in 2011, of which approximately $6.3 million results from the updated Gannett Fleming depreciation study.

The Parties agree that TGI will undertake an updated depreciation study to be included as part of TGI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.

23. Negative Salvage Values

On an annual basis, TGI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGI historically, and with this RRA TGI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($8.038 million and $11.29 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

24. Unrecovered Losses

Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."

Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 per cent for the provision of utility service to ratepayers (as discussed in the response to BCUC IR 2.131.1.4).

The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this agreement. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

25. Changes to CCA Rates

TGI amended its 2007 and 2008 tax returns to reflect changes to CCA rates announced in 2007 but not enacted until 2009. TGI proposed this benefit be shared in accordance with the terms of the PBR settlement. Some Parties have expressed the view, however, that all of the benefit should have been flowed through to customers via the Tax Deferral Account. The Parties, acting in good faith, have concluded that they have a fundamental and legitimate disagreement regarding the terms of the 2004-2009 PBR Settlement Agreement as it relates to the items to be included in the Tax Deferral Account. TGI has nevertheless agreed, as a compromise in furtherance of reaching an overall Agreement among the Parties, to include the full value of the incremental tax benefit associated with the difference in the CCA rates for 2007 and 2008 totalling $921,000 and remove the proposed 50% sharing benefit from the Earnings Sharing Mechanism.

26. Taxes – Tax Benefits Relating to Prior Periods – SCP Landscaping Costs

TGI had proposed to accelerate the deduction of the remaining Regulatory Tax balance of SCP Landscaping costs (amounting to approximately $8.2 million) in 2009. That proposal would have resulted in the related tax benefit of approximately $2.4 million being flowed through the Earnings Sharing Mechanism pursuant to the PBR Settlement Agreement, resulting in a net benefit to customers of approximately $1.2 million.

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The Parties agree that, instead, TGI will continue to amortize the balance of SCP Landscaping costs for 2009 as contemplated in the approved rates for 2009 and consistent with prior years, resulting in a deduction of approximately $0.3 million for Regulatory Tax purpose in 2009 and a related tax benefit. TGI will then deduct the remaining balance (approximately $7.9 million) in 2010 with the full value of the remaining benefit (approximately $2.3 million) going to customers reflected as a reduction in revenue requirements in 2010.

The Parties agree that the acceleration of this benefit to customers was the result of tax planning actions taken by TGI and acknowledge that the agreed upon treatment set out above reflects customers receiving 100% of the value of the deductions of the SCP Landscaping costs. The intervenor Parties to this Agreement will not seek any additional recovery in respect of SCP Landscaping costs.

27. Overheads Capitalized

The Parties agree to a change in the overheads capitalized rate to 14 per cent of Gross O&M for 2010 and 2011 which reflects the approximate actual Overheads Capitalized rate for 2009.

28. International Financial Reporting Standards ("IFRS") 2010 Impact

Issue No. 4 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "International Financial Reporting Standards ("IFRS") – no IFRS impact in 2010."

The Parties agree to defer the 2010 revenue requirement impact of IFRS to be recovered in rates in 2011 (relating specifically to capitalization of the current service portion of pension and OPEB related costs; capitalization of inspection costs; and timing of depreciation expense) up to a maximum of $1.0 million. Amounts, if any, over $1.0 million would be deferred and recovered in rates after 2011 based on the amortization approved by the Commission at that time.

PART III – REQUESTS UNCHANGED FROM THE APPLICATION

The Parties agree to the following items set out in this section, which are consistent with the proposals in TGI's Application.

29. Rate Proposals as per Application Part III, Section D .1 - Approvals Sought

The Parties agree to the following rate proposals, as set out in TGI's Application:

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(a) Allocation of delivery margin rate changes - Annual margin increase allocated to variable (volumetric & demand) based delivery charges, with no change to fixed (basic and admin fee) charges in each year (Application Page 513, Item 1).

(b) Earnings Sharing Mechanism (ESM) rider (incl. end of term capital) - Change the ESM rate rider to be ($0.040)/GJ effective January 1st, 2010, and change the estimated ESM rate rider to be ($0.046)/GJ effective January 1st. 2011. ESM amount to include End of Term Capital phase out and to be amortized over two years. The final 2011 rider amount will be adjusted based on 2009 actual earnings. TGI will submit an application to change the 2011 ESM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010 (Application Page 513, Item 3).

(c) Rate Stabilization Adjustment Mechanism (RSAM) rider - Change the RSAM rate rider to be ($0.053)/GJ effective January 1st, 2010 and change the estimated RSAM rate rider to be ($0.052)/GJ effective January 1st, 2011. The 2011 rider amount will be adjusted based on 2009 actual results and 2010 year to date actual results. TGI will submit an application to change the 2011 RSAM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010 (Application - Page 514 Item 4).

30. <u>Accounting Policy Changes as per Application Part III, Section D.1 - Approvals Sought - to be effective January 1, 2010</u>

The Parties agree to the following accounting policy changes, as set out in TGI's Application:

(a) Training and Feasibility Study Costs to be treated as O&M expense, rather than capital (Application Page 515 and 516, Item 11).

(b) Capitalization of Major Inspection Costs, including the creation of a new Asset Class (Application Page 515 and 516, Item 11).

(c) Capitalization of the Current Service portion of Pensions and OPEBs expense that is applicable to capital projects (Application Page 515 and 516, Item 11).

(d) Capitalization of Deprecation on Assets used in Construction (Application Page 515 and 516, Item 11).

(e) All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time (Application Page 515 and 516, Item 11).

(f) Treatment of Vehicle Lease as a capital lease and inclusion of the NBV of vehicles in rate base (Application Page 515 and 516, Item 11).

(g) Discontinuation the Software Tax Credit as part of the CIAC additions (Application Page 515 and 516, Item 11).

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31. Various Accounting Related Proposals as per Application Part III, Section D .1 - Approvals Sought effective January 1, 2010

The Parties agree to the following accounting related changes, as set out in TGI's Application:

(a) Adoption of the Cash Working Capital Lead/Lag Days as set out in the Lead/Lag study (Application page 515, Item 8c).

(b) Consolidated Core Market Administration Expenses (for TGI, TGVI and TGW), including allocation percentages to TGVI and TGW (Application page 515, Item 8d).

(c) Modify the Pricing Methodology for Company Use Gas to be based on market-based Sumas pricing, rather than pricing for expired "netback" contracts (Application page 514, Item 7a).

(d) The MCRA will absorb any volumes not used or excess volumes required for company use gas, as opposed to the O&M costs being adjusted for the differences (Application page 514, Item 7b).

32. Tariff Change Proposals as per Application Part III, Section D .1 - Approvals Sought, Item 12 & 13

The Parties agree to the following Tariff changes, as set out in TGI's Application:

(a) New NGV Transportation Service (RS 26)

(b) Revised Fee New Customer Application fee from $85 to $25

(c) Revised Fee Meter Testing fee from $30 to $60

33. Deferral Account Proposals as per Application Part III, Section D .1 - Approvals Sought, Item 10

The Parties agree to the continuation, modification or adoption of the following deferral accounts as set out in TGI's Application:

(a) Deferral Accounts - No Change:

i. CCRA, MCRA, RSAM, and associated Interest and Revelstoke Propane (Application pages 429 and 430, Items (1) (a), (1) (b), (1) (c), (1) (d), (1) (e)).

ii. NGV Conversion Grants (Application page 432, Item (2) (b)).

iii. Property Tax variance (Application page 433, Item (3) (a)).

iv. Insurance variance (Application page 433, Item (3) (b)).

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v. BCUC Levies variance (Application page 433, Item (3) (d)).

vi. Interest variance (Application page 434, Item (3) (e)).

vii. Olympic Security costs (Application page 434, Item (3) (g)).

viii. IFRS conversion costs (Application page 435, Item (3) (h)).

ix. Accounts Amortized in 2010 (Application page 438, Item (6) (a)).

x. SCP PST Reassessment (Application page 439, Item (6) (b)).

xi. Deferred Service Line Installation Fee (Application page 439, Item (6) (d)).

xii. ESM (Application page 440, Item (6) (e)).

(b) Deferral Accounts - Modified:

i. SCP Mitigation Revenues Variance Account - combine the two currently approved accounts into one account (Application page 431, Item (1) (f)).

ii. Pension & OPEB variance - modify to add OPEB (Application page 433, Item (3) (c)).

iii. Tax variance - broader (changes in tax laws, practices, reassessments) (Application page 434, Item (3) (f)).

iv. Pension and OPEB funding Differences - expand to include pension funding differences and include addition in rate base not net of tax (Application page 437, Item (5) (c)).

(c) Deferral Accounts - New:

i. Interest variance calculation on gas in storage inventory (Application page 434, Item (3) (e)).

ii. Costs of applications (CCE, ROE, RRA) (Application page 435, Item (4)).

iii. IFRS Transitional Deferral Account (Application page 435, Item (5) (a)).

iv. Gains and Losses on Asset Disposition (Application page 436, Item (5) (b)).

v. CCE CPCN Costs (incremental non-capital costs plus timing impacts) (Application page 437, Item (5) (d)).

vi. LILO Reassessment (Application page 439, Item (6) (c)).

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34. Transfer Pricing Policy (TPP) and Code of Conduct (COC)

The Parties agree that the existing COC and TPP Policies will be maintained.

PART IV – REVISED FINANCIAL SCHEDULES

The revised Financial Schedules follow.

13. Financial Schedules

Summary of TGI 2010 and 2011 Revenue Requirement Increase

Nov 5, 2009 NSP Agreement

		2010 ($ Millions)		Incremental 2011 ($ Millions)	Cumulative 2011 ($ Millions)	
Rebase from Formula Capital and O&M						
Rate Base- Net Plant in Service						
Equity Finance Expense	$ (2.0)		$ -			
Debt Finance Expense	(3.0)		-			
Utility O&M	(8.0)		-			
Overheads Capitalized	1.3					
After Tax Depreciation	(10.0)		-			
Tax Impacts of Rebase Depreciation	(4.3)		-			
Other Revenue	2.6		-			
Taxes	1.0	$ (22.4)	-	$ -	$ (22.4)	
Volumes/Revenue Related						
Change in Gross Margin due to Customer Growth	$ (4.6)		(3.7)			
Change in Use Rate	(4.7)		4.7			
Change in Other Revenue	(1.6)		(1.9)			
All Others	(1.8)	(12.7)	(1.5)	(2.4)	(15.1)	
O&M Forecast						
Change in overheads capitalized- change in O&M	(1.2)		(0.7)			
Change in O&M & Vehicle Lease Forecast	14.9	13.7	11.5	10.8	24.5	
Depreciation & Amortization Forecast						
After Tax Change in Depreciation from GPIS Additions/Retirements	3.7		2.3			
Change in Amortization	(2.2)	1.5	4.0	6.3	7.8	
Other						
Higher Property Taxes	1.6		1.0			
Change in Income Tax Expense	(0.4)		(0.1)			
Rate Base changes to support customer growth	1.8		2.5			
Interest Expense	2.1		5.4			
Rounding Difference	0.2	5.3	(0.1)	8.7	14.0	
Total Revenue Increase/(Decrease) Before Accounting Standard Changes		$ (14.6)		$ 23.4	$ 8.7	
Accounting Standard Changes						
Change in Overhead Capitalized Rate & Methodology	11.2		-			
Impacts on O&M	(0.3)	10.9	(2.0)	(2.0)	8.9	
After Tax change in Depreciation Rates	20.8		0.4			
After Tax change in Depreciation Commencement	1.9		-			
Tax Impacts of Depreciation Changes	9.0	31.7	0.1	0.5	32.2	
Total Revenue Increase from Accounting Standard Changes		$ 42.6		$ (1.5)	$ 41.1	
Net Revenue Increase - June 15, 2009 Application		**$ 27.9**		**$ 21.9**	**$ 49.8**	
Negotiatied Settlement Process Adjustments- please refer to Settlement Agreement for detail		(37.1)			(28.8)	
Adjusted Revenue (Decrease) / Increase		$ (9.2)	-1.73%		$ 21.0	3.93%
2010 Revenue Surplus deferred (pre-tax)*		9.2			(9.2)	
Net Revised Revenue (Decrease) / Increase- Negotiated Settlement Agreement Nov 5, 2009		**$ -**			**$ 11.8**	

*After Tax 2010 Revenue Surplus is $6.5 million

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Core	2010 Non-Core	2010 Bypass and Special Rates	2010 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,487,998	$1,430,710	$61,497	$12,094	$1,504,300	$16,302	- Tab C-13, Schedule 16
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	16,276	-	-	16,276	16,276	-	- Tab C-13, Schedule 26
8								
9	Total Revenue	1,504,274	1,430,710	61,497	28,369	1,520,576	16,302	
10								
11	Less - Cost of Gas	(975,597)	(986,394)	(759)	(817)	(987,970)	(12,373)	- Tab C-13, Schedule 19
12								
13	Gross Margin	$528,677	$444,316	$60,738	$27,552	$532,606	$3,929	
14								
15	Revenue Deficiency (Surplus)	$27,865	$0	$0	$0	**$0**	($27,865)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.27%	0.00%	0.00%	0.00%	0.00%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.85%	0.00%	0.00%	0.00%	0.00%		
20								

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Core	2011 Non-Core	2011 Bypass and Special Rates	2011 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,489,519	$1,433,011	$61,612	$12,094	$1,506,716	$17,197	- Tab C-13, Schedule 17
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	18,253	-	-	18,253	18,253	-	- Tab C-13, Schedule 27
8								
9	Total Revenue	1,507,772	1,433,011	61,612	30,347	1,524,969	17,197	
10								
11	Less - Cost of Gas	(976,614)	(988,047)	(759)	(821)	(989,627)	(13,013)	- Tab C-13, Schedule 21
12								
13	Gross Margin	$531,158	$444,964	$60,853	$29,526	$535,342	$4,184	
14								
15	Revenue Deficiency (Surplus)	$49,846	$10,340	$1,414	$0	**$11,754**	($38,092)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	9.38%	2.32%	2.32%	0.00%	2.20%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	3.31%	0.72%	2.30%	0.00%	0.77%		
20								

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 4

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	113,863	-	113,863	1,440	- Tab C-13, Schedule 14
3	Transportation	88,255	90,743	-	90,743	2,488	- Tab C-13, Schedule 14
4		200,678	204,606	-	204,606	3,928	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.565	$0.000	$12.565	($0.236)	
8	Transportation	$0.869	$0.811	$0.000	$0.811	($0.058)	
9	Average	$7.554	$7.352	$0.000	$7.352	($0.202)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,430,710	$0	$1,430,710	$16,074	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	24,497	-	-	-	(24,497)	- Tab C-13, Schedule 22
14	RSAM Revenue						
15	Transportation - Existing Rates	73,362	73,591	-	73,591	229	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	3,368		-	-	(3,368)	- Tab C-13, Schedule 22
17	**Total**	1,515,863	1,504,301	-	1,504,301	(11,562)	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	987,970	-	987,970	12,373	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	540,266	516,331	-	516,331	(23,935)	
22							
23	Operation and Maintenance	192,823	177,559	-	177,559	(15,264)	- Tab C-13, Schedule 28
24	Operating Leases	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	49,193	-	49,193	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	103,796	88,893	-	88,893	(14,903)	- Tab C-13, Schedule 33
27	Removal Cost Provision		8,038	-	8,038	8,038	- Tab C-13, Schedule 33
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 33
29	NSP Provision (IFRS -$800 + ESM $225 + RSDA $6537)		5,963	-	5,963	5,963	
30	Other Operating Revenue	(22,422)	(22,455)	-	(22,455)	(33)	- Tab C-13, Schedule 26
31		323,390	307,191	-	307,191	(16,199)	
32	Utility Income Before Income Taxes	216,876	209,140	-	209,140	(7,736)	
33							
34	Income Taxes	31,622	24,923	-	24,923	(6,699)	- Tab C-13, Schedule 35
35							
36	**EARNED RETURN**	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 10
37							
38							
39	**UTILITY RATE BASE**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	- Tab C-13, Schedule 8
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	7.27%		7.27%	-0.04%	- Tab C-13, Schedule 10

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 5

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,326	113,846	-	113,846	1,520	- Tab C-13, Schedule 15
3	Transportation	88,438	91,014	-	91,014	2,576	- Tab C-13, Schedule 15
4		200,764	204,860	-	204,860	4,096	
5							
6	Average Rate per GJ						
7	Sales	$12.997	$12.587	$0.000	$12.678	($0.319)	
8	Transportation	$0.898	$0.810	$0.000	$0.825	($0.073)	
9	Average	$7.668	$7.355	$0.000	$7.412	($0.256)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,416,102	$1,433,011	$0	$1,433,011	$16,909	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	43,822	-	10,341	10,341	(33,481)	- Tab C-13, Schedule 24
14							
15	Transportation - Existing Rates	73,417	73,705	-	73,705	288	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	6,024		1,413	1,413	(4,611)	- Tab C-13, Schedule 24
17	**Total**	1,539,365	1,506,716	11,754	1,518,470	(20,895)	
18							
19	Cost of Gas Sold (Including Gas Lost)	976,614	989,627	-	989,627	13,013	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	562,751	517,089	11,754	528,843	(33,908)	
22							
23	Operation and Maintenance	201,617	184,625	-	184,625	(16,992)	- Tab C-13, Schedule 28
24	Operating Leases	-	-	-	-	-	
25	Property and Sundry Taxes	50,211	50,211	-	50,211	-	- Tab C-13, Schedule 32
26	Depreciation and Amortization	110,496	88,588	-	88,588	(21,908)	- Tab C-13, Schedule 34
27	Removal Cost Provision		11,290	-	11,290	11,290	- Tab C-13, Schedule 34
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 34
29	NSP Provision (IFRS $800 + ESM $225)		1,025	-	1,025	1,025	
30	Other Operating Revenue	(24,359)	(24,394)	-	(24,394)	(35)	- Tab C-13, Schedule 27
31		337,965	311,345	-	311,345	(26,620)	
32	Utility Income Before Income Taxes	224,786	205,744	11,754	217,498	(7,288)	
33							
34	Income Taxes	31,654	21,449	3,115	24,564	(7,090)	- Tab C-13, Schedule 36
35							
36	**EARNED RETURN**	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 11
37							
38							
39	**UTILITY RATE BASE**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	- Tab C-13, Schedule 9
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.37%	7.01%		7.34%	-0.03%	- Tab C-13, Schedule 11

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(110,056)	(109,062)	-	(109,062)	994	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	(2,069)	-	(2,069)	(205)	- Tab C-13, Schedule 37
5	Accounting Income After Tax	73,334	73,086	-	73,086	(248)	
6	Add (Deduct) - Timing Differences	5,999	(4,958)	-	(4,958)	(10,957)	- Tab C-13, Schedule 37
7	Taxable Income After Tax	79,333	68,128	-	68,128	(11,205)	
8	Taxable Income Adj - SCP Landscaping Deduction	-	(7,834)	-	(7,834)	(7,834)	
9	Taxable Income Adj - Tax on SCP Landscaping	-	2,233	-	2,233	2,233	
10	Adjusted Taxable Income After Tax	$79,333	62,527	-	$62,527	(16,806)	
11							
12		28.500%	28.500%	28.500%	28.500%	0.000%	
13	1 - Current Income Tax Rate	71.500%	71.500%	71.500%	71.500%	0.000%	
14							
15	Taxable Income	$110,955	$87,450	$0	$87,450	($23,505)	
16							
17	**Total Income Tax**	$31,622	$24,923	$0	$24,923	($6,699)	
18							

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(115,430)	(114,982)	-	(114,982)	448	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	1,974	(4,769)	-	(4,769)	(6,743)	- Tab C-13, Schedule 38
5	Accounting Income After Tax	79,676	64,544	8,639	73,183	(6,493)	
6	Add (Deduct) - Timing Differences	8,118	(5,053)	-	(5,053)	(13,171)	- Tab C-13, Schedule 38
7	Taxable Income After Tax	87,794	59,491	8,639	68,130	(19,664)	
8	Taxable Income Adjustment	-	-	-	-	-	
9	Taxable Income Adjustment	-	-	-	-	-	
10	Adjusted Taxable Income After Tax	$87,794	59,491	8,639	$68,130	(39,328)	
11							
12		26.500%	26.500%	26.500%	26.500%	0.000%	
13	1 - Current Income Tax Rate	73.500%	73.50%	73.500%	73.500%	0.000%	
14							
15	Taxable Income	$119,448	$80,940	$11,754	$92,694	($26,754)	
16							
17	**Total Income Tax**	$31,654	$21,449	$3,115	$24,564	($7,090)	(X-Ref - Tab C-13, Schedule 5)
18							

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UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,315,365	$0	$3,315,365	($2,225)	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	-	-	-	-	-	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,449,336	3,453,394	-	3,453,394	4,058	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($780,174)	$0	($780,174)	($987)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(840,835)	(835,365)	-	(835,365)	5,470	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($176,845)	($176,845)	$0	($176,845)	$0	- Tab C-13, Schedule 52
9	CIAC, Ending	(183,817)	(183,885)	-	(183,885)	(68)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$44,146	$0	$44,146	$0	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	47,061	47,062	-	47,062	1	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,441,849	$0	$2,441,849	$3,125	
15							
16							
17	Adjustment to 13-Month Average	13,537	13,537	-	13,537	-	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	(27,015)	(30,797)	-	(30,797)	(3,782)	- Tab C-13, Schedule 54
20	Cash Working Capital	(6,778)	(7,563)	-	(7,563)	(785)	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	103,439	103,439	-	103,439	-	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	284,455	284,455	-	284,455	-	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(284,455)	(284,455)	-	(284,455)	-	- Tab C-13, Schedule 61
24	LILO Benefit	(1,648)	(1,648)	-	(1,648)	-	
25	**Utility Rate Base**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	(X-Ref - Tab C-13, Schedule 10)

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UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	Adjustments	Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,449,336	$3,453,394	$0	$3,453,394	$4,058	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,535,828	3,538,378	-	3,538,378	2,550	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($840,835)	($835,365)	$0	($835,365)	$5,470	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(899,386)	(885,651)	-	(885,651)	13,735	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($183,817)	($183,885)	$0	($183,885)	($68)	- Tab C-13, Schedule 53
9	CIAC, Ending	(194,646)	(194,753)	-	(194,753)	(107)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$47,061	$47,062	$0	$47,062	$1	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	50,241	50,245	-	50,245	4	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,481,891	$2,494,713	$0	$2,494,713	$12,822	
15							
16							
17	Adjustment to 13-Month Average	-	-	-	-	-	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	10,347	6,770	-	6,770	(3,577)	- Tab C-13, Schedule 55
20	Cash Working Capital	(6,133)	(6,953)	6	(6,947)	(814)	- Tab C-13, Schedule 57
21	Other Working Capital (incl. Construction Advances)	120,091	120,091	-	120,091	-	- Tab C-13, Schedule 57
22	Future Income Taxes Regulatory Asset	292,155	292,155	-	292,155	-	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(292,155)	(292,155)	-	(292,155)		- Tab C-13, Schedule 61
24	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
25	**Utility Rate Base**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	(X-Ref - Tab C-13, Schedule 11)

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.49%	6.870%	4.22%	
3	Unfunded Debt			88,809	3.50%	2.250%	0.08%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			887,309	35.01%	8.483%	2.97%	
6								
7		- Tab C-13, Schedule 8		$2,534,444	100.00%		7.27%	
8								
9	2010 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.49%	6.870%	4.22%	$107,064
11	Unfunded Debt		$88,809					
12	Adjustment, Revised Rates		-	88,809	3.50%	2.250%	0.08%	1,998
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			887,309	35.01%	8.470%	2.97%	75,155
15		(X-Ref - Tab C-13, Schedule 4)						
16		- Tab C-13, Schedule 8		$2,534,444	100.00%		7.27%	$184,217

TERASEN GAS INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,453	62.06%	6.836%	4.24%	
3	Unfunded Debt			76,982	2.93%	4.500%	0.13%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			920,331	35.01%	7.529%	2.64%	
6								
7		- Tab C-13, Schedule 9		$2,628,766	100.00%		7.01%	
8								
9	2011 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,631,453	62.06%	6.836%	4.24%	$111,518
11	Unfunded Debt		$76,982					
12	Adjustment, Revised Rates		4	76,986	2.93%	4.500%	0.13%	3,464
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			920,333	35.01%	8.470%	2.97%	77,952
15		(X-Ref - Tab C-13, Schedule 5)						
16		- Tab C-13, Schedule 9		$2,628,772	100.00%		7.34%	$192,934

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UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	113,863	-	113,863	1,440	- Tab C-13, Schedule 14
3	Transportation	88,255	90,743	-	90,743	2,488	- Tab C-13, Schedule 14
4		200,678	204,606	-	204,606	3,928	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.565	$0.000	$12.565	($0.236)	
8	Transportation	$0.869	$0.811	$0.000	$0.811	($0.058)	
9	Average	$7.554	$7.352	$0.000	$7.352	($0.202)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,430,710	$0	$1,430,710	$16,074	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	24,497	-	-	-	(24,497)	- Tab C-13, Schedule 22
14		-					
15	Transportation - Existing Rates	73,362	73,591	-	73,591	229	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	3,368		-	-	(3,368)	- Tab C-13, Schedule 22
17	**Total**	1,515,863	1,504,301	-	1,504,301	(11,562)	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	987,970	-	987,970	12,373	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	540,266	516,331	-	516,331	(23,935)	
22							
23	Operation and Maintenance	192,823	177,559	-	177,559	(15,264)	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	49,193	-	49,193	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	103,796	88,893	-	88,893	(14,903)	- Tab C-13, Schedule 33
27	Removal Cost Provision		8,038	-	8,038	8,038	- Tab C-13, Schedule 33
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 33
29	NSP Provision (IFRS -$800 + ESM $225 + RSDA $6537)		5,963	-	5,963	5,963	
30	Other Operating Revenue	(22,422)	(22,455)	-	(22,455)	(33)	- Tab C-13, Schedule 26
31		323,390	307,191	-	307,191	(16,199)	
32	Utility Income Before Income Taxes	216,876	209,140	-	209,140	(7,736)	
33							
34	Income Taxes	31,622	24,923	-	24,923	(6,699)	- Tab C-13, Schedule 35
35							
36	**EARNED RETURN**	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 10
37							
38							
39	**UTILITY RATE BASE**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	- Tab C-13, Schedule 8
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	7.27%		7.27%	-0.04%	- Tab C-13, Schedule 10

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UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,326	113,846	-	113,846	1,520	- Tab C-13, Schedule 15
3	Transportation	88,438	91,014	-	91,014	2,576	- Tab C-13, Schedule 15
4		200,764	204,860	-	204,860	4,096	
5							
6	Average Rate per GJ						
7	Sales	$12.997	$12.587	$0.000	$12.678	($0.319)	
8	Transportation	$0.898	$0.810	$0.000	$0.825	($0.073)	
9	Average	$7.668	$7.355	$0.000	$7.412	($0.256)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,416,102	$1,433,011	$0	$1,433,011	$16,909	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	43,822	-	10,341	10,341	(33,481)	- Tab C-13, Schedule 24
14		-					
15	Transportation - Existing Rates	73,417	73,705	-	73,705	288	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	6,024		1,413	1,413	(4,611)	- Tab C-13, Schedule 24
17	**Total**	1,539,365	1,506,716	11,754	1,518,470	(20,895)	
18							
19	Cost of Gas Sold (Including Gas Lost)	976,614	989,627	-	989,627	13,013	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	562,751	517,089	11,754	528,843	(33,908)	
22							
23	Operation and Maintenance	201,617	184,625	-	184,625	(16,992)	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	50,211	50,211	-	50,211	-	- Tab C-13, Schedule 32
26	Depreciation and Amortization	110,496	88,588	-	88,588	(21,908)	- Tab C-13, Schedule 34
27	Removal Cost Provision		11,290	-	11,290	11,290	- Tab C-13, Schedule 34
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 34
29	NSP Provision (IFRS $800 + ESM $225)		1,025	-	1,025	1,025	
30	Other Operating Revenue	(24,359)	(24,394)	-	(24,394)	(35)	- Tab C-13, Schedule 27
31		337,965	311,345	-	311,345	(26,620)	
32	Utility Income Before Income Taxes	224,786	205,744	11,754	217,498	(7,288)	
33							
34	Income Taxes	31,654	21,449	3,115	24,564	(7,090)	- Tab C-13, Schedule 36
35							
36	**EARNED RETURN**	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 11
37							
38							
39	**UTILITY RATE BASE**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	- Tab C-13, Schedule 9
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.37%	7.01%		7.34%	-0.03%	- Tab C-13, Schedule 11

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Schedule 14

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	June 15, 2009 Application	2010 Terajoules Core and Non-Core	2010 Terajoules Bypass and Special Rates	2010 Terajoules Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,829.2	69,174.3	0.0	69,174.3	1,345.1	
3	Schedule 2 - Small Commercial	24,374.3	24,374.3		24,374.3	0.0	
4	Schedule 3 - Large Commercial	16,818.6	16,818.6		16,818.6	0.0	
5							
6	Schedules 1, 2 and 3	109,022.1	110,367.2	0.0	110,367.2	1,345.1	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,098.5	3,184.6		3,184.6	86.1	
10							
11	Industrials	0.0					
12	Schedule 7 - Interruptible	14.2	22.7		22.7	8.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,423.2	113,862.9	0.0	113,862.9	1,439.7	(X-Ref - Tab C-13, Schedule 4)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	8,103.2	7,795.6	15,898.8	2,808.4	
20	- Interruptible Service	11,849.7	11,080.5	0.0	11,080.5	(769.2)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		137.5	137.5	11.7	
22	Burrard Thermal - Firm	2,343.9		1,719.4	1,719.4	(624.5)	
23	TGVI - Firm	36,368.3		36,368.3	36,368.3	0.0	
24	Schedule 23 - Large Commercial	6,134.0	6,134.0		6,134.0	0.0	
25	Schedule 25 - Firm Service	13,159.6	12,944.4	873.1	13,817.5	657.9	
26	Schedule 27 - Interruptible Service	5,183.5	5,587.4		5,587.4	403.9	
22							
23	Total Transportation Service	88,255.2	43,849.5	46,893.9	90,743.4	2,488.2	(X-Ref - Tab C-13, Schedule 4)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,678.4	157,712.4	46,893.9	204,606.3	3,927.9	(X-Ref - Tab C-13, Schedule 23)

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Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	June 15, 2009 Application	2011 Terajoules Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,190.5	68,578.9	0.0	68,578.9	1,388.4	
3	Schedule 2 - Small Commercial	24,603.1	24,603.1		24,603.1	0.0	
4	Schedule 3 - Large Commercial	17,168.5	17,168.5		17,168.5	0.0	
5							
6	Schedules 1, 2 and 3	108,962.1	110,350.5	0.0	110,350.5	1,388.4	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,061.2	3,184.3		3,184.3	123.1	
10							
11	Industrials	0.0					
12	Schedule 7 - Interruptible	14.2	22.7		22.7	8.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,325.9	113,845.9	0.0	113,845.9	1,520.0	(X-Ref - Tab C-13, Schedule 5)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	8,103.2	7,795.6	15,898.8	2,808.4	
20	- Interruptible Service	11,830.5	11,080.5	0.0	11,080.5	(750.0)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		137.5	137.5	11.7	
22	Burrard Thermal - Firm	2,343.9		1,719.4	1,719.4	(624.5)	
23	TGVI - Firm	36,596.4		36,596.4	36,596.4	0.0	
24	Schedule 23 - Large Commercial	6,177.2	6,177.2		6,177.2	0.0	
25	Schedule 25 - Firm Service	13,102.0	12,944.1	873.1	13,817.2	715.2	
26	Schedule 27 - Interruptible Service	5,171.9	5,587.4		5,587.4	415.5	
22							
23	Total Transportation Service	88,438.1	43,892.4	47,122.0	91,014.4	2,576.3	(X-Ref - Tab C-13, Schedule 5)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,764.0	157,738.3	47,122.0	204,860.3	4,096.3	(X-Ref - Tab C-13, Schedule 25)

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Schedule 16

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$897,420	$912,822	$0	$912,822	$15,402	
3	Schedule 2 - Small Commercial	297,556	297,556		297,556	-	
4	Schedule 3 - Large Commercial	189,604	189,604		189,604	-	
5	Schedules 1, 2 and 3	1,384,580	1,399,982	-	1,399,982	15,402	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,404	28,012		28,012	609	
9		28,881	29,490	-	29,490	609	
10	Industrials						
11	Interruptible - Schedule 7	130	194	-	194	64	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,414,636	1,430,710	-	1,430,710	16,074	(X-Ref - Tab C-13, Schedule 4)
16							(X-Ref - Tab C-13, Schedule 12)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,189	1,270	6,459	79	
19	- Interruptible Service	9,743	9,270	-	9,270	(473)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,411	16,411	-	16,411	-	
24	Schedule 25 - Firm Service	24,509	23,970	775	24,744	235	
25	Schedule 27 - Interruptible Service	6,270	6,658	-	6,658	388	
26	Total T-Service	73,362	61,497	12,094	73,591	229	(X-Ref - Tab C-13, Schedule 4)
27							(X-Ref - Tab C-13, Schedule 12)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,487,998	$1,492,207	$12,094	$1,504,300	$16,302	(X-Ref - Tab C-13, Schedule 23)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C Tab 13 Schedule 17

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$891,764	$907,735	$0	$907,735	$15,971	
3	Schedule 2 - Small Commercial	300,831	300,831		300,831	-	
4	Schedule 3 - Large Commercial	193,720	193,720		193,720	-	
5	Schedules 1, 2 and 3	1,386,315	1,402,286	-	1,402,286	15,971	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,135	28,009		28,009	874	
9		28,613	29,487	-	29,487	874	
10	Industrials						
11	Interruptible - Schedule 7	130	194	-	194	64	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,416,102	1,433,011	-	1,433,011	16,908	- Tab C-13, Schedule 5
16							(X-Ref - Tab C-13, Schedule 13)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,189	1,270	6,459	79	
19	- Interruptible Service	9,729	9,270	-	9,270	(459)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,525	16,525	-	16,525	-	
24	Schedule 25 - Firm Service	24,475	23,969	775	24,744	269	
25	Schedule 27 - Interruptible Service	6,258	6,658	-	6,658	400	
26	Total T-Service	73,417	61,612	12,094	73,705	288	- Tab C-13, Schedule 5
27							(X-Ref - Tab C-13, Schedule 13)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,489,519	$1,494,622	$12,094	$1,506,716	$17,197	(X-Ref - Tab C-13, Schedule 25)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	51,798.7	$8.830	$457,371	15,692.9	$8.325	$130,649	1,682.7	$8.394	$14,124	$602,144
4	Schedule 2 - Small Commercial	17,866.8	8.972	160,297	5,791.0	8.449	48,931	716.5	8.554	6,129	215,357
5	Schedule 3 - Large Commercial	13,802.1	8.756	120,855	2,703.0	8.260	22,327	313.5	8.140	2,552	145,734
6	Schedules 1, 2 and 3	83,467.6		738,523	24,186.9		201,907	2,712.7		22,805	963,235
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,729.0	6.632	18,099	415.7	6.608	2,747	39.9	6.677	266	21,112
10											
11	Industrials										
12	Interruptible - Schedule 7	-	-	-	22.7	6.608	150	-	-	-	150
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	86,376.4		757,803	24,733.9		205,520	2,752.6		23,071	986,394
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	5,514.3	0.017	94	2,588.9	0.081	210	304
20	- Interruptible Service	10,726.2	0.007	71	329.1	0.365	120	25.2	-	-	191
21	Schedule 23 - Large Commercial	4,950.9	0.008	40	1,124.1	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,356.3	0.008	75	3,318.8	0.016	53	269.3	0.080	22	150
23	Schedule 27 - Interruptible Service	4,820.0	0.008	39	747.7	0.016	12	19.7	-	-	51
24	Total T-Service	29,853.4		225	11,034.0		297	2,962.1		237	759
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	116,229.8		$758,028	35,767.9		$205,817	5,714.7		$23,308	$987,153

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	15	7,475.8	-	-	319.8	0.050	16	31
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	137.5	0.049	7	7
6	Burrard Thermal - Firm	1,719.4	0.020	35	-	-	-	-	-	-	35
7	TGVI - Firm	36,368.3	0.020	730	-	-	-	-	-	-	730
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	873.1	0.016	14	-	-	-	14
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,087.7		780	8,348.9		14	457.3		23	817
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,317.5		$758,808	44,116.8		$205,831	6,172.0		$23,331	$987,970

(X-Ref - Tab C-13, Schedule 12) , (X-Ref - Tab C-13, Schedule 4)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	51,350.2	$8.846	$454,251	15,555.0	$8.342	$129,766	1,673.7	$8.410	$14,076	$598,093
4	Schedule 2 - Small Commercial	18,027.1	8.991	162,072	5,851.0	8.471	49,566	725.0	8.580	6,221	217,859
5	Schedule 3 - Large Commercial	14,042.4	8.770	123,157	2,801.4	8.259	23,136	324.7	8.149	2,646	148,939
6	Schedules 1, 2 and 3	83,419.7		739,480	24,207.4		202,468	2,723.4		22,943	964,891
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,728.9	6.632	18,098	415.5	6.606	2,745	39.9	6.677	266	21,109
10											
11	Industrials										
12	Interruptible - Schedule 7	-	-	-	22.7	6.608	150	-	-	-	150
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	86,328.4		758,759	24,754.2		206,079	2,763.3		23,209	988,047
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	5,514.3	0.017	94	2,588.9	0.081	210	304
20	- Interruptible Service	10,726.2	0.007	71	329.1	0.365	120	25.2	-	-	191
21	Schedule 23 - Large Commercial	4,974.0	0.008	40	1,144.2	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,356.0	0.008	75	3,318.8	0.016	53	269.3	0.080	22	150
23	Schedule 27 - Interruptible Service	4,820.0	0.008	39	747.7	0.016	12	19.7	-	-	51
24	Total T-Service	29,876.2		225	11,054.1		297	2,962.1		237	759
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	116,204.6		$758,984	35,808.3		$206,376	5,725.4		$23,446	$988,806

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	15	7,475.8	-	-	319.8	0.056	18	33
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	137.5	0.032	4	4
6	Burrard Thermal - Firm	1,719.4	0.020	35	-	-	-	-	-	-	35
7	TGVI - Firm	36,596.4	0.020	735	-	-	-	-	-	-	735
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	873.1	0.016	14	-	-	-	14
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,315.8		785	8,348.9		14	457.3		22	821
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,520.4		$759,769	44,157.2		$206,390	6,182.7		$23,468	$989,627

(X-Ref - Tab C-13, Schedule 13) , (X-Ref - Tab C-13, Schedule 5)

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue -- At Existing 2009 Rates -- Revenue ($000s)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Gross Margin -- At Existing 2009 Rates -- Margin ($000s)	Effective Increase / (Decrease) 0.00% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000s)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	69,174.3	$13.196	$912,822	$4.491	$310,678	$0.000	$0	754,076	$13.196	$912,822
4	Schedule 2 - Small Commercial	24,374.3	12.208	297,556	3.372	82,200	-	0	76,536	12.208	297,556
5	Schedule 3 - Large Commercial	16,818.6	11.273	189,604	2.608	43,870	-	0	5,022	11.273	189,604
6	Total Schedules 1 , 2 and 3	110,367.2		1,399,982		436,747		0	835,633		1,399,982
7											
8	Schedule 4 - Seasonal Service	184.6	8.003	1,477	1.343	248	-	0	16	8.003	1,477
9	Schedule 5 - General Firm Service	3,184.6	8.796	28,012	2.167	6,901	-	0	281	8.796	28,012
10											
11	Industrials										
12	Schedule 7 - Interruptible	22.7	8.542	194	1.938	44	-	0	2	8.542	194
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.062	1,044	3.628	377	-	0	32	10.062	1,044
15											
16	Total Core Sales	113,862.9		1,430,710		444,316		0	835,964		1,430,710
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	8,103.2	0.640	5,189	0.603	4,885	-	0	13	0.640	5,189
20	- Interruptible Service	11,080.5	0.837	9,270	0.819	9,079	-	0	22	0.837	9,270
21	Schedule 23 - Large Commercial	6,134.0	2.675	16,411	2.665	16,348	-	0	1,309	2.675	16,411
22	Schedule 25 - Firm Service	12,944.4	1.852	23,970	1.840	23,820	-	0	573	1.852	23,970
23	Schedule 27 - Interruptible Service	5,587.4	1.192	6,658	1.183	6,607	-	0	98	1.192	6,658
24											
25	Total T-Service	43,849.5		61,497		60,739		0	2,015		61,497
26											
27	Total Non-Bypass Sales & Transportation Service	157,712.4		$1,492,207		$505,055		$0	837,979		$1,492,207
28		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)				(X-Ref - Tab C-13, Schedule 2)			

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 0.00% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	7,795.6	0.163	1,270	0.159	1,239	-	-	8	0.163	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	137.5	0.386	53	0.338	46	-	-	1	0.386	53
6	Burrard Thermal - Firm	1,719.4	5.814	9,996	5.794	9,962	-	-	1		9,996
7	TGVI - Firm	36,368.3	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	873.1	0.887	775	0.871	761	-	-	7	0.887	775
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	46,893.9		12,094		12,008		-	19		12,094
12											
13	Total Bypass Sales and										
14	Transportation Service	46,893.9		12,094		12,008		-	19		12,094
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	204,606.3		$1,504,300		$517,063		$0	837,998		$1,504,300
18		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)				(X-Ref - Tab C-13, Schedule 2)			

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Margin ($000s)	Effective Increase / (Decrease) 2.32% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	68,578.9	$13.236	$907,735	$4.515	$309,643	$0.105	$7,196	759,267	$13.341	$914,931
4	Schedule 2 - Small Commercial	24,603.1	12.227	300,831	3.372	82,972	0.078	1,928	77,252	12.305	302,759
5	Schedule 3 - Large Commercial	17,168.5	11.283	193,720	2.608	44,781	0.061	1,040	5,126	11.344	194,760
6	Total Schedules 1 , 2 and 3	110,350.5		1,402,286		437,395		10,164	841,644		1,412,450
7											
8	Schedule 4 - Seasonal Service	184.6	8.0030	1,477	1.3430	248	0.0330	6	16	8.036	1,483
9	Schedule 5 - General Firm Service	3,184.3	8.7960	28,009	2.1670	6,900	0.0510	161	281	8.847	28,170
10											
11	Industrials										
12	Schedule 7 - Interruptible	22.7	8.5420	194	1.9380	44	0.0440	1	2	8.586	195
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.0620	1,044	3.6280	377	0.0870	9	32	10.149	1,053
15											
16	Total Core Sales	113,845.9		1,433,011		444,964		10,341	841,975		1,443,352
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	8,103.2	0.6400	5,189	0.6030	4,885	0.0140	113	13	0.654	5,302
20	- Interruptible Service	11,080.5	0.8370	9,270	0.8190	9,079	0.0190	210	22	0.856	9,480
21	Schedule 23 - Large Commercial	6,177.2	2.6750	16,525	2.6650	16,462	0.0620	383	1,318	2.737	16,908
22	Schedule 25 - Firm Service	12,944.1	1.8520	23,969	1.8400	23,819	0.0430	554	573	1.895	24,523
23	Schedule 27 - Interruptible Service	5,587.4	1.1920	6,658	1.1830	6,607	0.0270	153	98	1.219	6,811
24											
25	Total T-Service	43,892.4		61,612		60,853		1,413	2,024		63,025
26											
27	Total Non-Bypass Sales & Transportation Service	157,738.3		$1,494,622		$505,817		$11,754	843,999		$1,506,376
28		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)			(X-Ref - Tab C-13, Schedule 3)				

TERASEN GAS INC.

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 25

APPENDIX A
to Order G-141-09
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REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

			Revenue -- At Existing 2009 Rates --		Gross Margin -- At Existing 2009 Rates --		Increase / (Decrease) 2.32% of Margin			Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	7,795.6	0.1630	1,270	0.1587	1,237	-	-	8	0.1630	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	137.5	0.3860	53	0.3543	49	-	-	1	0.3860	53
6	Burrard Thermal - Firm	1,719.4	5.8140	9,996	5.7936	9,962	-	-	1	5.8140	9,996
7	TGVI - Firm	36,596.4	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	873.1	0.8870	775	0.8711	761	-	-	7	0.8870	775
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	47,122.0		12,094		12,008		-	19		12,094
12											
13	Total Bypass Sales and										
14	Transportation Service	47,122.0		12,094		12,008		-	19		12,094
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	204,860.3		$1,506,716		$517,825		$11,754	844,018		$1,518,470
18		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)				(X-Ref - Tab C-13, Schedule 3)			

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,982	$3,014	$32	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,879	2,880	1	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	74	74	-	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,017	6,050	33	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,457	3,457	-	(X-Ref - Tab C-13, Schedule 2)
16					
17	SCP Third Party Revenue	12,819	12,819	-	(X-Ref - Tab C-13, Schedule 2)
18					
19	TGVI SAP Lease Income	129	129	-	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	16,405	16,405	-	
23					(X-Ref - Tab C-13, Schedule 12)
24	**Total Other Operating Revenue**	$22,422	$22,455	$33	(X-Ref - Tab C-13, Schedule 4)

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OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,987	$3,020	$33	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,905	2,907	2	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	76	76	-	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,050	6,085	35	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,455	3,455	-	(X-Ref - Tab C-13, Schedule 3)
16					
17	SCP Third Party Revenue	14,798	14,798	-	(X-Ref - Tab C-13, Schedule 3)
18					
19	TGVI SAP Lease Income	56	56	-	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	18,309	18,309	-	
23					(X-Ref - Tab C-13, Schedule 13)
24	**Total Other Operating Revenue**	$24,359	$24,394	$35	(X-Ref - Tab C-13, Schedule 5)

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OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	M&E Costs	$ 43,087	$ 45,496	$ 48,663	
2	COPE Costs	24,792	29,505	31,938	
3	IBEW Costs	22,301	24,870	26,559	
4					
5	**Labour Costs**	**90,179**	**99,871**	**107,160**	
6					
7	Vehicle Costs	4,626	3,111	3,084	
8	Employee Expenses	3,979	5,212	5,227	
9	Materials and Supplies	5,579	7,251	7,191	
10	Computer Costs	7,612	11,192	11,991	
11	Fees and Administration Costs	27,369	27,860	28,512	
12	Contractor Costs	58,251	60,112	60,052	
13	Facilities	11,717	13,973	14,318	
14	Recoveries & Revenue	(14,235)	(22,117)	(22,854)	
15					
16	**Non-Labour Costs**	**104,899**	**106,593**	**107,520**	
17					
18					
19	**Total Gross O&M Expenses**	**195,078**	**206,464**	**214,680**	
20					
21	Less: Vehicle Lease Reclass	(1,804)	-	-	
22	Less: Capitalized Overhead	(28,113)	(28,905)	(30,055)	
23					(X-Ref - Tab C-13, Schedule 4)
24	**Total O&M Expenses**	**$ 165,162**	**$ 177,559**	**$ 184,625**	(X-Ref - Tab C-13, Schedule 5)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 29

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Supervision	100-11	$ 9,782	$ 10,331	$ 10,609	
2	Distribution Supervision Total	100-10	9,782	10,331	10,609	
3						
4	Operation Centre - Distribution	100-21	6,747	9,798	10,451	
5	Asset Management - Distribution	100-22	1,113	1,925	2,437	
6	Preventative Maintenance - Distribution	100-23	2,026	1,927	2,377	
7	Distribution Operations - General	100-24	4,720	5,096	5,512	
8	Emergency Management	100-25	6,582	5,240	5,488	
9	Distribution Operations Total	100-20	21,189	23,986	26,266	
10						
11	Distribution Corrective - Meters	100-31	1,176	1,433	1,524	
12	Distribution Corrective - Propane	100-32	5	5	5	
13	Distribution Corrective - Leak Repair	100-33	931	939	996	
14	Distribution Corrective - Stations	100-34	490	681	727	
15	Distribution Corrective - General	100-35	486	505	534	
16	Distribution Maintenance Total	100-30	3,089	3,562	3,785	
17						
18	**Distribution Total**	**100**	**34,060**	**37,879**	**40,660**	
19						
20	Transmission Supervision	200-11	2,448	3,079	3,161	
21	Transmission Supervision Total	200-10	2,448	3,079	3,161	
22						
23	Pipeline Operation	200-21	2,094	2,627	2,836	
24	Right of Way	200-22	1,407	1,282	1,345	
25	Compression	200-23	1,650	1,919	1,922	
26	Gas Control	200-24	2,264	2,896	3,105	
27	Transmission Pipeline Integrity Project (TPIP)	200-25	5,355	3,177	3,317	
28	Transmission Operations Total	200-20	12,771	11,902	12,525	
29						
30	Pipeline - Maintenance	200-31	167	189	194	
31	Compression - Maintenance	200-32	163	167	172	
32	TPIP - Maintenance	200-33	373	671	929	
33	Transmission Maintenance Total	200-30	702	1,027	1,295	
34						
35	**Transmission Total**	**200**	**15,921**	**16,008**	**16,980**	
36						
37	LNG Plant Operations	300-11	825	1,036	1,088	
38	LNG Plant Operations Total	300-10	825	1,036	1,088	
39	LNG Plant Maintenance	300-21	200	269	277	
40	LNG Plant Maintenance Total	300-20	200	269	277	
41						
42	**LNG Plant Total**	**300**	**1,025**	**1,305**	**1,365**	
43						
44	Measurement Operations	400-11	3,759	4,083	4,297	
45	Measurement Operations Total	400-10	3,759	4,083	4,297	
46						
47	Measurement Maintenance	400-21	1,804	2,208	2,334	
48	Measurement Maintenance Total	400-20	1,804	2,208	2,334	
49						
50	**Measurement Total**	**400**	**5,562**	**6,291**	**6,630**	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 30

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Facilities Management	500-10	5,580	6,277	5,968	
2	Shops & Stores	500-20	3,699	4,018	4,152	
3	Operations Engineering	500-30	6,368	8,121	8,679	
4	Property Services	500-40	988	1,174	1,307	
5	System Integrity	500-50	2,040	2,393	2,492	
6	Environmental Health & Safety	500-60	1,490	2,352	2,504	
7	Operations Governance	500-70	1,515	1,692	1,800	
8						
9	**General Operations Total**	**500**	**21,679**	**26,025**	**26,903**	
10						
11	Energy Efficiency	600-10	$ 1,624	$ -	$ -	
12	Marketing - Supervision	600-20	1,208	621	634	
13	Corporate & Marketing Communications	600-30	2,574	3,593	3,673	
14	Marketing Planning & Development	600-40	749	655	669	
15	**Marketing Total**	**600**	**6,156**	**4,868**	**4,976**	
16						
17	Customer Care - Supervision	700-10	1,089	2,069	2,126	
18	Customer Contact - ABSU contract	700-20	47,127	48,470	49,422	
19	Bad Debt Management and Administration	700-30	6,112	5,874	6,018	
20	Customer Management & Sales	700-40	3,349	3,949	4,176	
21	**Customer Care Total**	**700**	**57,677**	**60,361**	**61,742**	
22						
23	Business & IT Services - Supervision	800-10	1,419	1,239	1,268	
24	Application Management	800-20	9,313	12,682	13,512	
25	Infrastructure Management	800-30	5,208	6,461	6,775	
26	Procurement Services	800-40	736	824	874	
27	**Business & IT Services Total**	**800**	**16,675**	**21,205**	**22,428**	
28						
29	Administration & General	900-11	3,229	(207)	(1,185)	
30	Insurance	900-12	4,725	4,410	4,631	
31	Finance and Regulatory Affairs	900-13	9,585	9,641	9,994	
32	Shared Services Agreement	900-14	3,541	2,116	1,899	
33	Corporate Administration Total	900-10	21,080	15,960	15,339	
34	Forecasting	900-20	1,022	1,632	1,672	
35	Public Affairs	900-30	1,375	1,731	1,762	
36	Business Development	900-40	1,416	3,123	3,183	
37	Human Resources	900-50	5,440	6,687	6,930	
38	Other Post Employment Benefits (OPEB)	900-60	5,991	3,389	4,111	
39	**Administration & General Total**	**900**	**36,324**	**32,522**	**32,996**	
40						
41	**Total Gross O&M Expenses**		**195,078**	**206,464**	**214,680**	
42						
43	Less: Vehicle Lease Reclass		(1,804)	-	-	
44	Less: Capitalized Overhead		(28,113)	(28,905)	(30,055)	
45						(X-Ref - Tab C-13, Schedule 4)
46	**Total O&M Expenses**		**$ 165,162**	**$ 177,559**	**$ 184,625**	(X-Ref - Tab C-13, Schedule 5)

* Note : Line 29 "Administration and General" expenses show a reduction of $1.0 million. The allocation of this $1.0 million reduction will be determined at a later date.

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 31

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Total Expenses	2010 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,187	$16,187	$16,187	$0	
4						
5	General, School and Other	33,006	33,006	33,006	-	
6						(X-Ref - Tab C-13, Schedule 4)
7	Total	$49,193	$49,193	$49,193	$0	(X-Ref - Tab C-13, Schedule 12)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 32

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

			2011			
Line No.	Particulars	June 15, 2009 Application	Total Expenses	Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,067	$16,067	$16,067	$0	
4						
5	General, School and Other	34,144	34,144	34,144	-	
6						(X-Ref - Tab C-13, Schedule 5)
7	Total	$50,211	$50,211	$50,211	$0	(X-Ref - Tab C-13, Schedule 13)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 33

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$113,009	$98,312	($14,697)	- Tab C-13, Schedule 49
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,849)	(6,850)	(1)	- Tab C-13, Schedule 52
6		106,160	91,462	(14,698)	
7					
8	Add: Removal Cost Provision	-	8,038	8,038	(X-Ref - Tab C-13, Schedule 4)
9					
10		106,160	99,500	($6,660)	
11			(X-Ref - Tab C-13, Schedule 37)		
12	**Amortization Expense**				
13					
14	Amortization of Deferred Charges	($2,364)	($2,569)	($205)	- Tab C-13, Schedule 54
15					
16		(2,364)	(2,569)	(205)	
17					(X-Ref - Tab C-13, Schedule 4)
18	TOTAL	$103,796	96,931	($6,865)	(X-Ref - Tab C-13, Schedule 12)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 34

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$115,696	$100,534	($15,162)	- Tab C-13, Schedule 51
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,674)	(6,677)	(3)	- Tab C-13, Schedule 53
6		109,022	93,857	(15,165)	
7					
8	Add: Removal Cost Provision	-	11,290	11,290	(X-Ref - Tab C-13, Schedule 5)
9					
10		109,022	105,147	(15,165)	
11			(X-Ref - Tab C-13, Schedule 38)		
12	**Amortization Expense**				
13					
14	Amortization of Deferred Charges	$1,474	($5,269)	($6,743)	- Tab C-13, Schedule 55
15					
16		1,474	(5,269)	(6,743)	
17					(X-Ref - Tab C-13, Schedule 5)
18	TOTAL	$110,496	$99,878	($21,908)	(X-Ref - Tab C-13, Schedule 13)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 35

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(110,056)	(109,062)	-	(109,062)	994	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	(2,069)	-	(2,069)	(205)	- Tab C-13, Schedule 37
5	Accounting Income After Tax	73,334	73,086	-	73,086	(248)	
6	Add (Deduct) - Timing Differences	5,999	(4,958)	-	(4,958)	(10,957)	- Tab C-13, Schedule 37
7	Taxable Income After Tax	79,333	68,128	-	68,128	(11,205)	
8	Taxable Income Adj - SCP Landscaping Deduction	-	(7,834)	-	(7,834)	(7,834)	
9	Taxable Income Adj - Tax on SCP Landscaping	-	2,233	-	2,233	2,233	
10	Adjusted Taxable Income After Tax	$79,333	$62,527	$0	$62,527	($16,806)	
11							
12		28.500%	28.500%	28.500%	28.500%	0.000%	
13	1 - Current Income Tax Rate	71.500%	71.500%	71.500%	71.500%	0.000%	
14							
15	Taxable Income	110,955	$87,450	$0	$87,450	($23,505)	
16							(X-Ref - Tab C-13, Schedule 4)
17	**Total Income Tax**	$31,622	$24,923	$0	$24,923	($6,699)	(X-Ref - Tab C-13, Schedule 12)

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(115,430)	(114,982)	-	(114,982)	448	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	1,974	(4,769)	-	(4,769)	(6,743)	- Tab C-13, Schedule 38
5	Accounting Income After Tax	79,676	64,544	8,639	73,183	(6,493)	
6	Add (Deduct) - Timing Differences	8,118	(5,053)	-	(5,053)	(13,171)	- Tab C-13, Schedule 38
7	Taxable Income After Tax	87,794	59,491	8,639	68,130	(19,664)	
8	Taxable Income Adjustment	-	-	-	-	-	
9	Taxable Income Adjustment	-	-	-	-	-	
10	Adjusted Taxable Income After Tax	$87,794	$59,491	$8,639	$68,130	($19,664)	
11							
12		26.500%	26.500%	26.500%	26.500%	0.000%	
13	1 - Current Income Tax Rate	73.500%	73.500%	73.500%	73.500%	0.000%	
14							
15	Taxable Income	119,448	$80,940	$11,754	$92,694	($26,754)	
16							(X-Ref - Tab C-13, Schedule 5)
17	**Total Income Tax**	$31,654	$21,449	$3,115	$24,564	($1,767)	(X-Ref - Tab C-13, Schedule 13)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 37

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	($2,364)	($2,569)	($205)	- Tab C-13, Schedule 54
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	($1,864)	($2,069)	($205)	(X-Ref - Tab C-13, Schedule 35)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation & Removal Cost Provision	$106,160	99,500	($6,660)	- Tab C-13, Schedule 33
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	1,597	1,597	-	
15	Pension Expense	4,779	4,779	-	
16	OPEB Expense	5,320	5,320	-	
17	2010 Revenue Surplus (Net of Tax)	-	6,537	6,537	
18					
19	Deductions:				
20	Capital Cost Allowance	(98,544)	(96,990)	1,554	- Tab C-13, Schedule 39
21	Cumulative Eligible Capital Allowance	(1,001)	(1,001)	-	
22	Debt Issue Costs	(1,206)	(1,206)	-	
23	Vehicle Lease Payment	(3,149)	(3,149)	-	
24	Pension Contributions	(7,115)	(7,115)	-	
25	OPEB Contributions	(503)	(503)	-	
26	Overheads Capitalized Expensed for Tax Purposes	-	(12,388)	(12,388)	
27	Overhead Capitalization Rate Change	-	-	-	
28	CCA Rate Change of 2007 & 2008	-	-	-	
29	Long Term Compensation	-	-	-	
30	Discounts on Debt Issue and Other	-	-	-	
31	Major Inspection Costs	(1,060)	(1,060)	-	
32					
33	Total Timing Differences	$5,999	($4,958)	($10,957)	(X-Ref - Tab C-13, Schedule 35)
					(X-Ref - Tab C-13, Schedule 6)

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 38

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	$1,474	($5,269)	($6,743)	- Tab C-13, Schedule 55
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	$1,974	($4,769)	($6,743)	(X-Ref - Tab C-13, Schedule 36)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation & Removal Cost Provision	$109,022	105,147	($3,875)	- Tab C-13, Schedule 34
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	2,029	2,029	-	
15	Pension Expense	5,704	5,704	-	
16	OPEB Expense	5,297	5,297	-	
17	2010 Revenue Surplus	-	-	-	
18					
19	Deductions:				
20	Capital Cost Allowance	(100,844)	(97,259)	3,585	- Tab C-13, Schedule 40
21	Cumulative Eligible Capital Allowance	(937)	(937)	-	
22	Debt Issue Costs	(1,003)	(1,003)	-	
23	Vehicle Lease Payment	(3,736)	(3,736)	-	
24	Pension Contributions	(7,322)	(7,322)	-	
25	OPEB Contributions	(503)	(503)	-	
26	Overheads Capitalized Expensed for Tax Purposes	-	(12,881)	(12,881)	
27	Overhead Capitalization Rate Change	-	-	-	
28	CCA Rate Change of 2007 & 2008	-	-	-	
29	Long Term Compensation	-	-	-	
30	Discounts on Debt Issue and Other	-	-	-	
31	Major Inspection Costs	(310)	(310)	-	
32					
33	Total Timing Differences	$8,118	($5,053)	($13,171)	(X-Ref - Tab C-13, Schedule 36)
					(X-Ref - Tab C-13, Schedule 7)

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CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Class	CCA Rate %	12/31/2009 UCC Balance	Adjustments	2010 Net Additions	2010 CCA	12/31/2010 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,190,923	($7,834)	$371	($47,331)	$1,136,129
2	1.3	6%	8,120	-	2,755	(570)	10,305
3	2	6%	164,165	-	-	(9,850)	154,315
4	3	5%	2,826	-	-	(141)	2,685
5	6	10%	206	-	-	(21)	185
6	7	15%	3,824	-	2,188	(738)	5,274
7	8	20%	15,184	-	2,441	(3,281)	14,344
8	10	30%	3,135	-	1,629	(1,185)	3,579
9	12	100%	-	3,087	11,604	(8,889)	5,802
10	13	Manual	2,682	-	167	(890)	1,959
11	14	Manual	2	-	-	(2)	-
12	17	8%	223	-	-	(18)	205
13	38	30%	225	-	30	(72)	183
14	39	25%	-	-	-	-	-
15	45	45%	891	-	-	(401)	490
16	47	8%	4,798	-	451	(402)	4,847
17	49	8%	65,970	-	12,903	(5,794)	73,079
18	50 / 52	55% / 100%	1,432	-	4,489	(5,276)	645
19	51	6%	168,386	-	67,541	(12,129)	223,798
20							
21		Total	$1,632,992	($4,747)	$106,569	($96,990)	$1,637,824
22						(X-Ref - Tab C-13, Schedule 37)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate %	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,136,129	$0	$0	($45,445)	$1,090,684
2	1.3	6%	10,305	-	3,590	(726)	13,169
3	2	6%	154,315	-	-	(9,259)	145,056
4	3	5%	2,685	-	-	(134)	2,551
5	6	10%	185	-	-	(19)	166
6	7	15%	5,274	-	1,617	(912)	5,979
7	8	20%	14,344	-	2,214	(3,090)	13,468
8	10	30%	3,579	-	1,607	(1,315)	3,871
9	12	100%	5,802	-	11,000	(11,302)	5,500
10	13	Manual	1,959	-	51	(883)	1,127
11	14	Manual	-	-	-	-	-
12	17	8%	205	-	-	(17)	188
13	38	30%	183	-	30	(59)	154
14	39	25%	-	-	-	-	-
15	45	45%	490	-	-	(220)	270
16	47	8%	4,847	-	1,651	(454)	6,044
17	49	8%	73,079	-	6,024	(6,087)	73,016
18	50 / 52	55% / 100%	645	-	5,000	(1,729)	3,916
19	51	6%	223,798	-	72,667	(15,608)	280,857
20							
21		Total	$1,637,824	$0	$105,451	($97,259)	$1,646,016
22						(X-Ref - Tab C-13, Schedule 38)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
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Schedule 41

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,315,365	$0	$3,315,365	($2,225)	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	-				-	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,449,336	3,453,394	-	3,453,394	4,058	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($780,174)	$0	($780,174)	($987)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(840,835)	(835,365)	-	(835,365)	5,470	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($176,845)	($176,845)	$0	($176,845)	$0	- Tab C-13, Schedule 52
9	CIAC, Ending	(183,817)	(183,885)	-	(183,885)	(68)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$44,146	$0	$44,146	$0	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	47,061	47,062	-	47,062	1	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,441,849	$0	$2,441,849	$3,125	
15							
16	Adjustment to 13-Month Average	13,537	13,537	-	13,537	-	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	(27,015)	(30,797)	-	(30,797)	(3,782)	- Tab C-13, Schedule 54
19	Cash Working Capital	(6,778)	(7,563)	-	(7,563)	(785)	- Tab C-13, Schedule 56
20	Other Working Capital (incl. Construction Advances)	103,439	103,439	-	103,439	-	- Tab C-13, Schedule 56
21	Future Income Taxes Regulatory Asset	284,455	284,455	-	284,455	-	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(284,455)	(284,455)	-	(284,455)	-	- Tab C-13, Schedule 61
23	LILO Benefit	(1,648)	(1,648)	-	(1,648)	-	
24	**Utility Rate Base**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	(X-Ref - Tab C-13, Schedule 10)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 42

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	Adjustments	Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,449,336	$3,453,394	$0	$3,453,394	$4,058	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-				-	
3	Gas Plant in Service, Ending	3,535,828	3,538,378	-	3,538,378	2,550	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($840,835)	($835,365)	$0	($835,365)	$5,470	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(899,386)	(885,651)	-	(885,651)	13,735	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($183,817)	($183,885)	$0	($183,885)	($68)	- Tab C-13, Schedule 53
9	CIAC, Ending	(194,646)	(194,753)	-	(194,753)	(107)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$47,061	$47,062	$0	$47,062	$1	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	50,241	50,245	-	50,245	4	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,481,891	$2,494,713	$0	$2,494,713	$12,822	
15							
16	Adjustment to 13-Month Average	0	-	-	-	-	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	10,347	6,770	-	6,770	(3,577)	- Tab C-13, Schedule 55
19	Cash Working Capital	(6,133)	(6,953)	6	(6,947)	(814)	- Tab C-13, Schedule 57
20	Other Working Capital (incl. Construction Advances)	120,091	120,091	-	120,091	-	- Tab C-13, Schedule 57
21	Future Income Taxes Regulatory Asset	292,155	292,155	-	292,155	-	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(292,155)	(292,155)	-	(292,155)	-	- Tab C-13, Schedule 61
23	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
24	**Utility Rate Base**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	(X-Ref - Tab C-13, Schedule 11)

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2009 - 2011
($000)

Line No.	Particulars	Projected 2009	Forecast 2010	Forecast 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4	Regular Capital Expenditures	85,425	93,511	93,597	
5	Gateway Project *	11,174	6,750	10,433	
6					
7	Total Regular Capital Expenditures	$ 96,599	$ 100,261	$ 104,030	
8					
9	Special Projects - CPCN's				
10	Vancouver LP Replacement	250	-	-	
11	Fraser River SBSA Rehabilitation	25,000	520	-	
12	Okanagan Reinforcement Project	500	500	500	
13	CCE CPCN	7,476	49,662	57,761	
14	Kootenay River Crossing	-	2,000	4,000	
15	Huntingdon Bypass	-	200	12,000	
16		0.00	0	0	
17	Total CPCN's	$ 33,226	$ 52,882	$ 74,261	
18					
19					
20	TOTAL CAPITAL EXPENDITURES	$ 129,825	$ 153,143	$ 178,291	
21					
22					
23	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
24					
25	Regular Capital				
26	Regular Capital Expenditures	96,599	100,260	104,030	
27	Add - Opening WIP	18,760	26,434	24,877	
28	Less - Opening WIP Adjustment	-	-	-	
29	Less - Closing WIP	(26,434)	(24,877)	(25,706)	
30	Capital Spares Inventory Reclassification	8,593	-	-	
31	Capital Vehicle Lease Addition	-	3,869	2,735	
32	Add - AFUDC	267	230	241	- Tab C-13, Schedule 45
33	Add - Overhead Capitalized	28,113	28,905	30,055	- Tab C-13, Schedule 47
34					
35	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 125,898	$ 134,821	$ 136,232	
36					
37	Special Projects - CPCN's				
38	CPCN Expenditures	33,226	52,882	74,261	
39	Add - Opening WIP	14,676	35,291	62,672	
40	Less - Closing WIP	(35,291)	(62,672)	(143,095)	
41	Less: Vancouver LP Removal costs (added to Accumulated Depreciation)	(394)	-	-	
42	Add - AFUDC	662	2,102	6,162	
43					- Tab C-13, Schedule 45
44	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$ 12,879	$ 27,603	-$ 0	- Tab C-13, Schedule 47
45		(X-Ref - Tab C-13, Schedule 41)			
46	TOTAL PLANT ADDITIONS	$ 138,777	$ 162,424	$ 136,232	
47					
48	Capital Vehicle Lease Opening Adjustment	-	26,103	-	- Tab C-13, Schedule 45
49					
50	TOTAL PLANT ADDITIONS and OPENING ADJUSTMENTS	$ 138,777	$ 188,527	$ 136,232	
51					
52					
53	* Spending associated with the Gateway Project is expected to be fully recovered via a contribution in aid of construction.				

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 44

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars (1)	Balance 12/31/2009 (2)	CPCN'S (3)	2010 Additions (4)	2010 AFUDC (5)	Retirements (6)	Transfers/ Recovery (7)	Balance 12/31/2010 (8)	Mid-year GPIS for Depreciation (9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688
10	461-00 Land Rights - Transmission	43,782	-	121	-	-	-	43,903	43,843
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-
14	402-01 Application Software - 12.5%	55,628	-	11,604	66	(8,954)	-	58,344	56,986
15	402-02 Application Software - 20%	8,051	-	-	-	(1,847)	-	6,204	7,128
16	TOTAL INTANGIBLE PLANT	111,006	-	11,725	66	(10,801)	-	111,996	111,501
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475
21	433 Manufact'd Gas - Equipment	425	-	425	-	-	-	850	638
22	434 Manufact'd Gas - Gas Holders	663	-	-	-	-	-	663	663
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885
27	443 Gas Holders - Storage	16,655	-	519	4	-	-	17,178	16,917
28	446 Compressor Equipment	-	-	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-
30	448 Purification Equipment	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	-	-	-	-	-	23,410	23,410
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	47,834	-	944	4	-	-	48,782	48,308
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690
37	463-00 Measuring Structures	4,949	-	-	-	-	-	4,949	4,949
38	464-00 Other Structures & Improvements	5,960	-	-	-	-	-	5,960	5,960
39	465-00 Mains	736,398	27,349	21,172	79	(1,063)	(1,985)	781,950	772,849 *
40	465-00 Mains - Inspection	-	-	1,505	6	-	1,985	3,496	1,748
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932
42	466-00 Compressor Equipment	111,042	-	1,769	7	-	-	112,818	111,930
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	-	-	-	-	-	29,409	29,409
45	467-10 Telemetering	8,494	-	106	-	-	-	8,600	8,547
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	919,667	27,349	24,552	92	(1,063)	-	970,597	958,807
50									
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.								

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 45

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	**DISTRIBUTION PLANT**									
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418	
3	472-00 Structures & Improvements	14,697	-	-	-	-	-	14,697	14,697	
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107	
5	473-00 Services	640,145	254	31,160	-	(7,790)	-	663,769	652,084	**
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229	
7	474-00 House Regulators & Meter Installations	134,325	-	13,786	3	(11,032)	-	137,082	135,704	
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070	
9	475-00 Mains	844,063	-	21,883	31	(2,192)	-	863,785	853,924	
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704	
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571	
12	477-00 Measuring & Regulating Equipment	82,546	-	5,423	21	(817)	-	87,173	84,860	
13	477-00 Telemetering	5,916	-	256	1	(13)	-	6,160	6,038	
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163	
15	478-10 Meters	184,767	-	9,883	-	(7,907)	-	186,743	185,755	
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027	
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251	
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	
19	TOTAL DISTRIBUTION PLANT	2,030,999	254	82,391	56	(29,751)	-	2,083,949	2,057,601	
20										
21	**GENERAL PLANT & EQUIPMENT**									
22	480-00 Land in Fee Simple	21,905	-	126	-	-	-	22,031	21,968	
23	481-00 Land Rights	-	-	-	-	-	-	-	-	
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286	
26	- Masonry Buildings	83,527	-	2,228	-	-	-	85,755	84,641	
27	- Leasehold Improvement	473	-	167	1	-	-	641	557	
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-	
29	483-30 GP Office Equipment	4,480	-	87	-	(90)	-	4,477	4,479	
30	483-40 GP Furniture	19,730	-	509	1	(5)	-	20,235	19,983	
31	483-10 GP Computer Hardware	18,220	-	4,489	10	(6,245)	-	16,474	17,347	
32	483-20 GP Computer Software	853	-	-	-	(20)	-	833	843	
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-	
34	484-00 Transportation Equipment	2,279	-	1,629	-	-	-	3,908	3,094	
35	484-00 Vehicles - Leased	-	-	3,869	-	(2,321)	26,103	27,651	26,877	
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209	
37	485-20 Heavy Mobile Equipment	561	-	30	-	-	-	591	576	
38	486-00 Small Tools & Equipment	32,177	-	1,137	-	-	-	33,314	32,746	
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24	
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-	
42	- Telephone	11,239	-	504	-	(202)	-	11,541	11,390	
43	- Radio	4,896	-	204	-	-	-	5,100	4,998	
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-	
45	TOTAL GENERAL PLANT	205,859	-	14,979	12	(8,883)	26,103	238,070	235,016	
46										
47	**UNCLASSIFIED PLANT**									
48	499 Plant Suspense	-	-	-	-	-	-	-	-	
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-	
53										
54	TOTAL CAPITAL	$3,315,365	$27,603	$134,591	$230	($50,498)	$26,103	$3,453,394	$3,411,233	
55	(X-Ref - Tab C-13, Schedule 8)		(X-Ref - Tab C-13, Schedule 43)					(X-Ref - Tab C-13, Schedule 49)		
56	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.							(X-Ref - Tab C-13, Schedule 8)		

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688
10	461-00 Land Rights - Transmission	43,903	-	124	-	-	-	44,027	43,965
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-
14	402-01 Application Software - 12.5%	58,344	-	11,000	66	(10,840)	-	58,570	58,457
15	402-02 Application Software - 20%	6,204	-	-	-	(1,147)	-	5,057	5,631
16	TOTAL INTANGIBLE PLANT	111,996	-	11,124	66	(11,987)	-	111,199	111,598
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475
21	433 Manufact'd Gas - Equipment	850	-	-	-	-	-	850	850
22	434 Manufact'd Gas - Gas Holders	663	-	-	-	-	-	663	663
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885
27	443 Gas Holders - Storage	17,178	-	1,894	17	-	-	19,089	18,134
28	446 Compressor Equipment	-	-	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-
30	448 Purification Equipment	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	-	-	-	-	-	23,410	23,410
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	48,782	-	1,894	17	-	-	50,693	49,738
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690
37	463-00 Measuring Structures	4,949	-	-	-	-	-	4,949	4,949
38	464-00 Other Structures & Improvements	5,960	-	-	-	-	-	5,960	5,960
39	465-00 Mains	781,950	-	18,761	78	(942)	-	799,847	790,899
40	465-00 Mains - Inspection	3,496	-	444	2	-	-	3,942	3,719
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932
42	466-00 Compressor Equipment	112,818	-	1,851	8	-	-	114,677	113,748
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	-	-	-	-	-	29,409	29,409
45	467-10 Telemetering	8,600	-	71	-	-	-	8,671	8,636
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	970,597	-	21,127	88	(942)	-	990,870	980,734

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418
3	472-00 Structures & Improvements	14,697	-	-	-	-	-	14,697	14,697
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107
5	473-00 Services	663,769	-	33,776	-	(8,444)	-	689,101	676,435
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229
7	474-00 House Regulators & Meter Installations	137,082	-	14,821	3	(11,859)	-	140,047	138,565
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070
9	475-00 Mains	863,785	-	22,408	31	(2,244)	-	883,980	873,883
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571
12	477-00 Measuring & Regulating Equipment	87,173	-	5,560	24	(838)	-	91,919	89,546
13	477-00 Telemetering	6,160	-	258	1	(13)	-	6,406	6,283
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163
15	478-10 Meters	186,743	-	10,391	-	(8,313)	-	188,821	187,782
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION PLANT	2,083,949	-	87,214	59	(31,711)	-	2,139,511	2,111,730
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,031	-	129	-	-	-	22,160	22,096
23	481-00 Land Rights	-	-	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286
26	- Masonry Buildings	85,755	-	2,869	-	-	-	88,624	87,190
27	- Leasehold Improvement	641	-	51	-	-	-	692	667
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,477	-	60	-	(991)	-	3,546	4,012
30	483-40 GP Furniture	20,235	-	418	1	(1,230)	-	19,424	19,830
31	483-10 GP Computer Hardware	16,474	-	5,000	10	-	-	21,484	18,979
32	483-20 GP Computer Software	833	-	-	-	(198)	-	635	734
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,908	-	1,607	-	-	-	5,515	4,712
35	484-00 Vehicles - Leased	27,651	-	2,735	-	(1,641)	-	28,745	28,198
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209
37	485-20 Heavy Mobile Equipment	591	-	30	-	-	-	621	606
38	486-00 Small Tools & Equipment	33,314	-	1,105	-	-	-	34,419	33,867
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-
42	- Telephone	11,541	-	464	-	(1,596)	-	10,409	10,975
43	- Radio	5,100	-	166	-	(954)	-	4,312	4,706
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	238,070	-	14,634	11	(6,610)	-	246,105	242,088
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	-	-	-	-	-	-	-
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-
53									
54	TOTAL CAPITAL	$3,453,394	$0	$135,993	$241	($51,250)	$0	$3,538,378	$3,495,886
55		(X-Ref - Tab C-13, Schedule 9)		(X-Ref - Tab C-13, Schedule 43)				(X-Ref - Tab C-13, Schedule 9)	(X-Ref - Tab C-13, Schedule 51)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 48

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	365	366
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	156	234
5	178-00 Organization Expense	728	1.00%	7	-	-	-	369	376
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	49	69
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	27	42
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	151	166
10	461-00 Land Rights - Transmission	43,843	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	-	19	$19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	56,986	12.50%	7,123	(4,264)	(8,954)	-	31,197	25,102
15	402-02 Application Software - 20%	7,128	20.00%	1,426	-	(1,847)	-	4,160	3,739
16	TOTAL INTANGIBLE PLANT	111,501		8,685	(4,264)	(10,801)	-	37,147	30,767
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	89	105
21	433 Manufact'd Gas - Equipment	638	6.30%	40	-	-	-	51	91
22	434 Manufact'd Gas - Gas Holders	663	3.90%	26	-	-	-	173	199
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	24	27
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	152	212
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	3.65%	178	-	-	-	2,252	2,430
27	443 Gas Holders - Storage	16,917	2.18%	369	-	-	-	9,684	10,053
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	3.36%	787	-	-	-	8,336	9,123
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	48,308		1,479	-	-	-	20,762	22,241
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	3.84%	564	-	-	-	5,264	5,828
37	463-00 Measuring Structures	4,949	4.27%	211	-	-	-	1,314	1,525
38	464-00 Other Structures & Improvements	5,960	2.88%	172	-	-	-	1,365	1,537
39	465-00 Mains	772,849 *	1.63%	12,597	-	(1,063)	-	182,855	194,389
40	465-00 Mains - INSPECTION	1,748	Term	691	-	-	-	-	691
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	794	841
42	466-00 Compressor Equipment	111,930	3.18%	3,559	-	-	-	35,074	38,633
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	7.19%	2,115	-	-	-	6,266	8,381
45	467-10 Telemetering	8,547	1.33%	114	-	-	-	6,083	6,197
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.01%	2	-	-	-	7	9
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	277	295
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	958,807		20,090	-	(1,063)	-	239,700	258,727
50									
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.								

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
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Schedule 49

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision: 2010 (Cr.)	Provision: Adjust-ments	Provision: Retirements	Provision: Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,697	3.60%	529	-	-	-	3,231	3,760
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	16	21
5	473-00 Services	652,084 **	2.25%	14,672	-	(7,790)	-	78,219	85,101
6	473-00 Services - LILO	43,229	2.20%	951	-	-	-	16,079	17,030
7	474-00 House Regulators & Meter Installations	135,704	5.21%	7,070	-	(11,032)	-	(2,418)	(6,380)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,272	8,624
9	475-00 Mains	853,924	1.89%	16,139	-	(2,192)	-	235,807	249,754
10	475-00 Mains - LILO	39,704	2.00%	794	-	-	-	15,605	16,399
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	403	546
12	477-00 Measuring & Regulating Equipment	84,860	5.72%	4,854	-	(817)	-	12,756	16,793
13	477-00 Telemetering	6,038	0.25%	15	-	(13)	-	6,386	6,388
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	185,755	5.31%	9,864	-	(7,907)	-	38,504	40,461
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,067	4,397
17	478-20 Instruments	11,251	4.03%	453	-	-	-	2,815	3,268
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,057,601		56,171	-	(29,751)	-	419,972	446,392
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,968	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	4,633	-	-	(3,059)	1,768
26	- Masonry Buildings	84,641	2.50%	2,116	1,048	-	-	7,996	11,160
27	- Leasehold Improvement	557	10.00%	56	218	-	-	88	362
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,479	6.67%	299	726	(90)	-	1,937	2,872
30	483-40 GP Furniture	19,983	5.00%	999	(824)	(5)	-	12,176	12,346
31	483-10 GP Computer Hardware	17,347	20.00%	3,469	(7,882)	(6,245)	-	17,871	7,213
32	483-20 GP Computer Software	843	20.00%	169	-	(20)	-	445	594
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,094	7.70%	238	(2,099)	-	-	2,832	971
35	484-00 Vehicles - Leased	26,877	Lease Term	2,464	14,066	(2,321)	-	-	14,209
36	485-10 Heavy Work Equipment	209	6.64%	14	39	-	-	73	126
37	485-20 Heavy Mobile Equipment	576	8.48%	49	424	-	-	(332)	141
38	486-00 Small Tools & Equipment	32,746	5.00%	1,637	570	-	-	14,380	16,587
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	6	8
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	11,390	6.67%	760	506	(202)	-	5,647	6,711
43	- Radio	4,998	6.67%	333	(696)	-	-	2,527	2,164
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	235,016		12,799	10,729	(8,883)	-	62,600	77,245
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,411,233		$99,224	$6,465	($50,498)	$0	$780,174	$835,365
52		(X-Ref - Tab C-13, Schedule 45)						(X-Ref - Tab C-13, Schedule 8)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(912)					
54									
55	**Net Depreciation Expense**			$98,312					
56				(X-Ref - Tab C-13, Schedule 33)					
57	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.								

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 50

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	366	367
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	234	312
5	178-00 Organization Expense	728	1.00%	7	-	-	-	376	383
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	69	89
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	42	57
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	166	181
10	461-00 Land Rights - Transmission	43,965	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	$0	$19	19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	58,457	12.50%	7,307	-	(10,840)	-	25,102	21,569
15	402-02 Application Software - 20%	5,631	20.00%	1,126	-	(1,147)	-	3,739	3,718
16	TOTAL INTANGIBLE PLANT	111,598		8,569	-	(11,987)	-	30,767	27,349
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	105	121
21	433 Manufact'd Gas - Equipment	850	6.30%	54	-	-	-	91	145
22	434 Manufact'd Gas - Gas Holders	663	3.90%	26	-	-	-	199	225
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	27	30
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	212	272
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	3.65%	178	-	-	-	2,430	2,608
27	443 Gas Holders - Storage	18,134	2.18%	395	-	-	-	10,053	10,448
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	3.36%	787	-	-	-	9,123	9,910
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	49,738		1,519	-	-	-	22,241	23,760
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	3.84%	564	-	-	-	5,828	6,392
37	463-00 Measuring Structures	4,949	4.27%	211	-	-	-	1,525	1,736
38	464-00 Other Structures & Improvements	5,960	2.88%	172	-	-	-	1,537	1,709
39	465-00 Mains	790,899	1.63%	12,892	-	(942)	-	194,389	206,339
40	465-00 Mains - INSPECTION	3,719	Term	553	-	-	-	691	1,244
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	841	888
42	466-00 Compressor Equipment	113,748	3.18%	3,617	-	-	-	38,633	42,250
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	7.19%	2,115	-	-	-	8,381	10,496
45	467-10 Telemetering	8,636	1.33%	115	-	-	-	6,197	6,312
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.01%	2	-	-	-	9	11
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	295	313
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	980,734		20,306	-	(942)	-	258,727	278,091

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,697	3.60%	529	-	-	-	3,760	4,289
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	21	26
5	473-00 Services	676,435	2.25%	15,220	-	(8,444)	-	85,101	91,877
6	473-00 Services - LILO	43,229	2.20%	951	-	-	-	17,030	17,981
7	474-00 House Regulators & Meter Installations	138,565	5.21%	7,219	-	(11,859)	-	(6,380)	(11,020)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,624	8,976
9	475-00 Mains	873,883	1.89%	16,516	-	(2,244)	-	249,754	264,026
10	475-00 Mains - LILO	39,704	2.00%	794	-	-	-	16,399	17,193
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	546	689
12	477-00 Measuring & Regulating Equipment	89,546	5.72%	5,122	-	(838)	-	16,793	21,077
13	477-00 Telemetering	6,283	0.25%	16	-	(13)	-	6,388	6,391
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	187,782	5.31%	9,971	-	(8,313)	-	40,461	42,119
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,397	4,727
17	478-20 Instruments	11,251	4.03%	453	-	-	-	3,268	3,721
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,111,730		57,621	-	(31,711)	-	446,392	472,302
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,096	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	-	-	-	1,768	1,962
26	- Masonry Buildings	87,190	2.50%	2,180	-	-	-	11,160	13,340
27	- Leasehold Improvement	667	10.00%	67	-	-	-	362	429
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,012	6.67%	268	-	(991)	-	2,872	2,149
30	483-40 GP Furniture	19,830	5.00%	991	-	(1,230)	-	12,346	12,107
31	483-10 GP Computer Hardware	18,979	20.00%	3,796	-	-	-	7,213	11,009
32	483-20 GP Computer Software	734	20.00%	147	-	(198)	-	594	543
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	4,712	7.70%	363	-	-	-	971	1,334
35	484-00 Vehicles - Leased	28,198	Lease Term	2,709	-	(1,641)	-	14,209	15,277
36	485-10 Heavy Work Equipment	209	6.64%	14	-	-	-	126	140
37	485-20 Heavy Mobile Equipment	606	8.48%	51	-	-	-	141	192
38	486-00 Small Tools & Equipment	33,867	5.00%	1,693	-	-	-	16,587	18,280
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	8	10
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	10,975	6.67%	732	-	(1,596)	-	6,711	5,847
43	- Radio	4,706	6.67%	314	-	(954)	-	2,164	1,524
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	242,088		13,521	-	(6,610)	-	77,245	84,156
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,495,886		$101,536	$0	($51,250)	$0	$835,365	$885,651
52		(X-Ref - Tab C-13, Schedule 47)					(X-Ref - Tab C-13, Schedule 9)		
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(1,002)					
54									
55	**Net Depreciation Expense**			$100,534					
56				(X-Ref - Tab C-13, Schedule 34)					

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
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Schedule 52

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	Adjustment	2010 Additions	2010 Retirements	Balance 12/31/2010	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$141,389	$0	$6,424	$0	$147,813	
4							
5	Transmission Contributions	10,915	-	4,550	-	15,465	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	24,541	-	-	(3,934)	20,607	
11							
12	TOTAL Contributions	176,845	-	10,974	(3,934)	183,885	(X-Ref - Tab C-13, Schedule 8)
13							(X-Ref - Tab C-13, Schedule 41)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(32,291)	-	(3,765)	-	(36,056)	
19							
20	Transmission Contributions	-	-	(263)	-	(263)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(11,854)	-	(2,822)	3,934	(10,742)	
26							
27	TOTAL Amortization	(44,146)	-	(6,850)	3,934	(47,062)	(X-Ref - Tab C-13, Schedule 8)
28							(X-Ref - Tab C-13, Schedule 41)
29	**NET CONTRIBUTIONS**	$132,699	$0	$4,124	$0	$136,823	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 53

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$147,813	$0	$6,029	$0	$153,842	
4							
5	Transmission Contributions	15,465	-	8,333	-	23,798	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	20,607	-	-	(3,494)	17,113	
11							
12	TOTAL Contributions	183,885	-	14,362	(3,494)	194,753	(X-Ref - Tab C-13, Schedule 9)
13							(X-Ref - Tab C-13, Schedule 42)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(36,056)	-	(3,928)	-	(39,984)	
19							
20	Transmission Contributions	(263)	-	(391)	-	(654)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(10,742)	-	(2,358)	3,494	(9,606)	
26							
27	TOTAL Amortization	(47,062)	-	(6,677)	3,494	(50,245)	(X-Ref - Tab C-13, Schedule 9)
28							(X-Ref - Tab C-13, Schedule 42)
29	**NET CONTRIBUTIONS**	$136,823	$0	$7,685	$0	$144,508	

APPENDIX A
to Order G-141-09

TERASEN GAS INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Forecast Balance 12/31/2009	Opening Balance Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2010	Mid-Year Average 2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	($22,742.7)	$0.0	$31,808.0	($9,065.3)	$22,742.7	$0.0	$0.0	$0.0	$0.0	($11,371.4)
3	CCRA Interest	(895.9)		1,253.0	(357.1)	895.9	-	-	-	(0.0)	(448.0)
4	Midstream Cost Reconciliation Account (MCRA)	36,423.3		(50,941.7)	14,518.4	(36,423.3)	-	-	-	(0.0)	18,211.7
5	MCRA Interest	(1,779.2)		2,488.4	(709.2)	1,779.2	-	-	-	-	(889.6)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(13,165.6)		-	-	-	-	6,137.8	(1,749.3)	(8,777.1)	(10,971.4)
7	RSAM Interest	(38.4)		(5.3)	1.5	(3.8)	-	18.3	(5.2)	(29.1)	(33.8)
8	Revelstoke Propane Cost Deferral Account	(38.8)		54.3	(15.5)	38.8	-	-	-	(0.0)	(19.4)
9	SCP Mitigation Revenues Variance Account	(4,118.1)	(1,538.2)	-	-	-	1,723.2	-	-	(3,933.1)	(4,794.7)
10	SCP West to East Transmission	(1,538.2)	1,538.2	-	-	-	-	-	-	-	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	6,370.2		25,845.0	(7,365.8)	18,479.2	(1,012.0)	-	-	23,837.4	15,103.8
14	NGV Conversion Grants	136.9		77.5	(22.1)	55.4	(43.5)	-	-	148.8	142.9
15											
16	Non-Controllable Items										
17	Property Tax Deferral	(743.8)		-	-	-	398.1	-	-	(345.7)	(544.8)
18	Insurance Variance	(686.0)		-	-	-	686.0	-	-	-	(343.0)
19	Pension & OPEB Variance	(686.4)		-	-	-	686.4	-	-	-	(343.2)
20	BCUC Levies Variance	(262.0)		-	-	-	262.0	-	-	-	(131.0)
21	Interest Variance	(2,232.2)		-	-	-	633.9	-	-	(1,598.3)	(1,915.3)
22	Interest Variance - Funding benefits via Customer Deposits	214.2		-	-	-	(13.1)	-	-	201.1	207.7
23	Income Tax Rate Variance	(615.9)		-	-	-	205.3	-	-	(410.6)	(513.3)
24	Olympics Security Costs Deferral	522.8		2,651.6	(755.7)	1,895.9	-	-	-	2,418.7	1,470.8
25	IFRS Conversion Costs	399.5		265.3	(75.6)	189.7	-	-	-	589.2	494.4
26											
27	Cost of Current Applications										
28	2009 ROE & Cost of Capital Application	$441.0		$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$352.8	$396.9
29	2010-2011 Revenue Requirement Application	795.2		-	-	-	(397.6)	-	-	397.6	596.4
30	CCE CPCN Application	189.0		-	-	-	(37.8)	-	-	151.2	170.1
31											
32	Other										
33	IFRS Transitional Adjustments	-		(7,602.7)	-	(7,602.7)	-	-	-	(7,602.7)	(7,602.7)
34	OPEB Funding	(32,551.8)	32,551.8	-	-	-	-	-	-	-	(16,275.9)
35	Pension & OPEB Funding	-	(32,551.8)	20,476.7	-	20,476.7	-	-	-	(12,075.1)	(6,037.6)
36	2010 Revenue Surplus Deferral Account	-		(6,537.0)	-	(6,537.0)	-	-	-	(6,537.0)	(3,268.5)
37											
38	Residual Deferred Charges										
39	SCP Tax Reassessment	7,408.3		-	-	-	-	-	-	7,408.3	7,408.3
40	Deferred Service Line Installation Fee	1,442.9		(1,442.9)	-	(1,442.9)	-	-	-	-	-
41	Earnings Sharing Mechanism	(13,123.6)		3,372.0	(961.0)	2,411.0	-	6,168.7	(1,758.1)	(6,302.0)	(9,712.8)
42	CCT Assessment	(2.5)		-	-	-	2.5	-	-	-	(1.3)
43	Carbon Tax Implementation	(95.0)		-	-	-	95.0	-	-	-	(47.5)
44	TGS Amalgamation	132.0		-	-	-	(132.0)	-	-	-	66.0
45	TGS O&M Variance	352.0		-	-	-	(352.0)	-	-	-	176.0
46	Carbon Tax Cost of Service	(44.0)		-	-	-	44.0	-	-	(0.0)	(22.0)
47	OSC Certification Compliance	91.1		-	-	-	(91.1)	-	-	-	45.6
48	Bad Debt Allowance for Rates 14 & 14A	(140.2)	140.2	-	-	-	-	-	-	-	-
49											
50	Total Deferred Charges for Rate Base	($40,581.9)	$140.2	$21,762.2	($4,807.4)	$16,954.8	$2,569.1	$12,324.8	($3,512.6)	($12,105.6)	($30,796.6)
51							(X-Ref - Tab C-13, Schedule 33)			(X-Ref - Tab C-13, Schedule 8)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Forecast Balance 12/31/2010	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
3	CCRA Interest	(0.0)	-	-	-	-	-	-	(0.0)	-
4	Midstream Cost Reconciliation Account (MCRA)	(0.0)	-	-	-	-	-	-	(0.0)	-
5	MCRA Interest	-	-	-	-	-	-	-	-	-
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,777.1)	-	-	-	-	5,970.8	(1,582.3)	(4,388.6)	(6,582.9)
7	RSAM Interest	(29.1)	199.0	(52.7)	146.3	-	19.3	(5.1)	131.4	51.2
8	Revelstoke Propane Cost Deferral Account	(0.0)	-	-	-	-	-	-	(0.0)	-
9	SCP Mitigation Revenues Variance Account	(3,933.1)	-	-	-	1,735.9	-	-	(2,197.2)	(3,065.2)
10	SCP West to East Transmission	-	-	-	-	-	-	-	-	-
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	23,837.4	29,619.0	(7,849.0)	21,770.0	(2,524.9)	-	-	43,082.5	33,460.0
14	NGV Conversion Grants	148.8	255.0	(67.6)	187.4	(51.1)	-	-	285.1	217.0
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(345.7)	-	-	-	184.2	-	-	(161.5)	(253.6)
18	Insurance Variance	-	-	-	-	-	-	-	-	-
19	Pension & OPEB Variance	-	-	-	-	-	-	-	-	-
20	BCUC Levies Variance	-	-	-	-	-	-	-	-	-
21	Interest Variance	(1,598.3)	-	-	-	721.6	-	-	(876.7)	(1,237.5)
22	Interest Variance - Funding benefits via Customer Deposits	201.1	-	-	-	(13.1)	-	-	188.0	194.6
23	Income Tax Rate Variance	(410.6)	-	-	-	205.3	-	-	(205.3)	(308.0)
24	Olympics Security Costs Deferral	2,418.7	-	-	-	(806.2)	-	-	1,612.5	2,015.6
25	IFRS Conversion Costs	589.2	119.3	(31.6)	87.7	(196.4)	-	-	480.5	534.9
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$352.8	$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$264.6	$308.7
29	2010-2011 Revenue Requirement Application	397.6	-	-	-	(397.6)	-	-	-	198.8
30	CCE CPCN Application	151.2	-	-	-	(37.8)	-	-	113.4	132.3
31										
32	Other									
33	IFRS Transitional Adjustments	(7,602.7)	68,819.0	-	68,819.0	-	-	-	61,216.3	26,806.8
34	OPEB Funding	-	-	-	-	-	-	-	-	-
35	Pension & OPEB Funding	(12,075.1)	(69,232.0)	-	(69,232.0)	-	-	-	(81,307.1)	(46,691.1)
36	2010 Revenue Surplus Deferral Account	(6,537.0)	-	-	-	6,537.0	-	-	-	(3,268.5)
37										
38	Residual Deferred Charges									
39	SCP Tax Reassessment	7,408.3	-	-	-	-	-	-	7,408.3	7,408.3
40	Deferred Service Line Installation Fee	-	-	-	-	-	-	-	-	-
41	Earnings Sharing Mechanism	(6,302.0)	1,686.0	(446.8)	1,239.2	-	6,888.2	(1,825.4)	-	(3,151.0)
42	CCT Assessment	-	-	-	-	-	-	-	-	-
43	Carbon Tax Implementation	-	-	-	-	-	-	-	-	-
44	TGS Amalgamation	-	-	-	-	-	-	-	-	-
45	TGS O&M Variance	-	-	-	-	-	-	-	-	-
46	Carbon Tax Cost of Service	(0.0)	-	-	-	-	-	-	(0.0)	-
47	OSC Certification Compliance	-	-	-	-	-	-	-	-	-
48	Bad Debt Allowance for Rates 14 & 14A	-	-	-	-	-	-	-	-	-
49										
50	Total Deferred Charges for Rate Base	($12,105.6)	$31,465.3	($8,447.7)	$23,017.6	$5,268.7	$12,878.3	($3,412.8)	$25,646.2	$6,770.4
51						(X-Ref - Tab C-13, Schedule 34)			(X-Ref - Tab C-13, Schedule 9)	

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
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WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$2,324	$1,539	$1,539	($785)	- Tab C-13, Schedule 58
4						
5	Customer Deposits	-	0	-	-	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(5,940)	(5,940)	(5,940)	-	
10						
11	Withholdings From Employees	(3,162)	(3,162)	(3,162)	-	
12						
13	Subtotal	(6,778)	(7,563)	(7,563)	(785)	(X-Ref - Tab C-13, Schedule 8)
14						(X-Ref - Tab C-13, Schedule 41)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	-	
17	Transmission Line Pack Gas	2,413	2,413	2,413	-	
18	Gas in Storage	100,494	100,494	100,494	-	
19	Inventory - Materials & Supplies	1,202	1,202	1,202	-	
20						
21	Subtotal	103,439	103,439	103,439	0	(X-Ref - Tab C-13, Schedule 8)
22						(X-Ref - Tab C-13, Schedule 41)
23	Total	$96,661	$95,876	$95,876	($785)	

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Tab 13
Schedule 57

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$3,186	$2,366	$2,372	($814)	- Tab C-13, Schedule 58
4						
5	Customer Deposits	-	0	-	0	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(6,063)	(6,063)	(6,063)	0	
10						
11	Withholdings From Employees	(3,256)	(3,256)	(3,256)	0	
12						
13	Subtotal	(6,133)	(6,953)	(6,947)	(814)	(X-Ref - Tab C-13, Schedule 9)
14						(X-Ref - Tab C-13, Schedule 42)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	0	
17	Transmission Line Pack Gas	4,731	4,731	4,731	-	
18	Gas in Storage	114,804	114,804	114,804	0	
19	Inventory - Materials & Supplies	1,226	1,226	1,226	0	
20						
21	Subtotal	120,091	120,091	120,091	0	(X-Ref - Tab C-13, Schedule 9)
22						(X-Ref - Tab C-13, Schedule 42)
23	Total	$113,958	$113,138	$113,144	($814)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Days	2009 Expenses	2009 Cash Working Capital	2010 Days	2010 Expenses	2010 Cash Working Capital	2011 Days	2011 Expenses	2011 Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
4	Expense Lead Days	39.0			38.4			38.2			- Tab C-13, Schedule 60
5											(X-Ref - Tab C-13, Schedule 56)
6	Net Lead/(Lag) Days	(4.0)	$1,306,297	($14,316)	0.4	$1,404,291	$1,539	0.6	$1,439,545	$2,366	(X-Ref - Tab C-13, Schedule 57)
7											
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
13	Expense Lead Days	39.0			38.4			38.2			- Tab C-13, Schedule 60
14											(X-Ref - Tab C-13, Schedule 56)
15	Net Lead/(Lag) Days	(4.0)	$1,306,297	($14,316)	0.4	$1,404,291	$1,539	0.6	$1,443,164	$2,372	(X-Ref - Tab C-13, Schedule 57)
16											
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$0			$0			$6	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

TERASEN GAS INC. Nov 5, 2009 NSP Agreement

Section C
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Schedule 59

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											- Tab C-13, Schedule 22
3	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
4	Residential and Commercial	$1,344,218	34.6	$46,509,939	$1,399,982	38.3	$53,675,914	$1,402,286	38.3	$53,763,147	
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,860	41.0	3,233,260	77,496	45.0	3,489,083	77,608	45.0	3,494,126	
6	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,044	41.7	43,552	
7											
8	Rates 22, Burrard, TGVI (Oth Rev), SCP (Oth Rev)	40,576	37.8	1,533,765	42,054	42.5	1,788,524	44,031	42.3	1,864,247	
9											
10	Total Gas Sales	1,464,730	35.0	51,318,621	1,520,576	38.8	58,997,073	1,524,969	38.8	59,165,072	
11					(X-Ref - Tab C-13, Schedule 2)			(X-Ref - Tab C-13, Schedule 3)			- Tab C-13, Schedule 26
12	Other Revenues										- Tab C-13, Schedule 27
13	Late Payment Charges	2,878	26.7	76,843	3,014	38.3	115,444	3,020	38.3	115,681	
14	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
15	Connection Charges	2,926	37.3	109,140	2,880	38.3	110,315	2,907	38.3	111,323	
16	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
17											
18											
19	Total Revenue	$1,470,895	35.0	$51,516,942	$1,526,755	38.8	$59,233,763	$1,531,110	38.8	$59,400,256	
20											
21											
22	**REVENUE, REVISED RATES**										
23											- Tab C-13, Schedule 22
24	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
25	Residential and Commercial	$1,344,218	34.6	$46,509,939	$1,399,982	38.3	$53,675,914	$1,412,450	38.3	$54,152,948	
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,860	41.0	3,233,260	77,496	45.0	3,489,083	78,866	45.0	3,550,934	
27	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,053	41.7	43,927	
28											
29	Rates 22, Burrard, TGVI, SCP (Other)	40,576	37.8	1,533,765	42,054	42.5	1,788,524	44,354	42.4	1,878,846	
30											
31	Total Gas Sales	1,464,730	35.0	51,318,621	1,520,576	38.8	58,997,073	1,536,723	38.8	59,626,655	
32											- Tab C-13, Schedule 26
33	Other Revenues										- Tab C-13, Schedule 27
34	Late Payment Charges	2,878	26.7	76,843	3,014	38.3	115,444	3,020	38.3	115,681	
35	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
36	Connection Charges	2,926	37.3	109,140	2,880	38.3	110,315	2,907	38.3	111,323	
37	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
38											
39											
40	Total Revenue	$1,470,895	35.0	$51,516,942	$1,526,755	38.8	$59,233,763	$1,542,864	38.8	$59,861,839	

TERASEN GAS INC.

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2											
3	Operating And Maintenance										- Tab C-13, Schedule 4
4	Expenses	$166,966	19.3	$3,222,444	$177,559	25.5	$4,527,755	$184,625	25.5	$4,707,938	- Tab C-13, Schedule 5
5											- Tab C-13, Schedule 4
6	Gas Purchases	930,677	40.7	37,878,554	987,970	40.2	39,716,394	989,627	40.2	39,783,006	- Tab C-13, Schedule 5
7											
8	Taxes Other Than Income										- Tab C-13, Schedule 31
9	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
10	Franchise Fees	10,044	430.0	4,318,920	10,259	420.3	4,311,858	10,292	420.3	4,325,728	
11	Carbon Tax	71,753	43.6	3,128,449	98,953	29.1	2,879,519	127,206	29.1	3,701,686	
12	GST - Net	12,520	7.2	90,131	12,997	38.8	504,291	13,034	38.8	505,738	
13	PST	40,647	43.6	1,772,209	42,437	37.1	1,574,413	43,101	37.1	1,599,047	
14	Income Tax	26,096	15.2	396,659	24,923	15.2	378,830	21,449	15.2	326,025	- Tab C-13, Schedule 6
15											- Tab C-13, Schedule 7
16	Total	$1,306,296	39.0	$50,997,738	$1,404,291	38.4	$53,991,446	$1,439,545	38.2	$55,049,590	
17											
18											
19	**EXPENSES, REVISED RATES**										
20											
21	Operating And Maintenance										- Tab C-13, Schedule 4
22	Expenses	$166,966	19.3	$3,222,444	$177,559	25.5	$4,527,755	$184,625	25.5	$4,707,938	- Tab C-13, Schedule 5
23											- Tab C-13, Schedule 4
24	Gas Purchases	930,677	40.7	37,878,554	987,970	40.2	39,716,394	989,627	40.2	39,783,006	- Tab C-13, Schedule 5
25											
26	Taxes Other Than Income										- Tab C-13, Schedule 31
27	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
28	Franchise Fees	10,044	430.0	4,318,920	10,259	420.3	4,311,858	10,376	420.3	4,361,033	
29	Carbon Tax	71,753	43.6	3,128,449	98,953	29.1	2,879,519	127,206	29.1	3,701,686	
30	GST - Net	12,520	7.2	90,131	12,997	38.8	504,291	13,136	38.8	509,665	
31	PST	40,647	43.6	1,772,209	42,437	37.1	1,574,413	43,420	37.1	1,610,882	
32	Income Tax	26,096	15.2	396,659	24,923	15.2	378,830	24,564	15.2	373,373	- Tab C-13, Schedule 6
33											- Tab C-13, Schedule 7
34	Total	$1,306,296	39.0	$50,997,738	$1,404,291	38.4	$53,991,446	$1,443,164	38.2	$55,148,005	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 61

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	($2,447,020)	($2,535,462)	($2,625,708)
3	Less: Undepreciated Capital Cost	(1,712,991)	(1,760,477)	(1,853,515)
4		(734,029)	(774,985)	(772,193)
5	Weighted Average Future Tax Rate	25%	25%	25%
6		(184,037)	(194,075)	(193,048)
7				
8	Total FIT Liability- After Tax (PP&E)	(184,037)	(194,075)	(193,048)
9	Total FIT Liability- After Tax (Non-PP&E)	(24,298)	(23,948)	(27,038)
10	Total FIT Liability- After Tax	(208,335)	(218,023)	(220,086)
11				
12	Tax Gross Up	(69,713)	(72,839)	(73,362)
13				
14	FIT Liability/Asset - End of Year	(278,048)	(290,862)	(293,448)
15				
16	FIT Liability/Asset - Opening Balance	(278,048)	(278,048)	(290,862)
17				
18	FIT Liability/Asset - Mid Year	(278,048)	(284,455)	(292,155)
19		(X-Ref - Tab C-13, Schedule 8)	(X-Ref - Tab C-13, Schedule 9)	
20			(X-Ref - Tab C-13, Schedule 41)	
21	Note: * Excludes Land, Software CIAC, and WIP.		(X-Ref - Tab C-13, Schedule 42)	

TERASEN GAS INC.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Nov 5, 2009 NSP Agreement

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Tab 13
Schedule 62

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.490%	6.870%	4.220%	$107,064
3	Unfunded Debt			88,809	3.500%	2.250%	0.080%	1,998
4	Common Equity			887,309	35.010%	8.483%	2.970%	75,270
5								
6		- Tab C-13, Schedule 8		$2,534,444	100.000%		7.270%	$184,332
7								
8	2010 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,558,326	61.490%	6.870%	4.220%	$107,064
10	Unfunded Debt		$88,809					
11	Adjustment, Revised Rates		0	88,809	3.500%	2.250%	0.080%	1,998
12	Common Equity			887,309	35.010%	8.470%	2.970%	75,155
13								
14		- Tab C-13, Schedule 8		$2,534,444	100.000%		7.269%	$184,217
15							(X-Ref - Tab C-13, Schedule 4)	

TERASEN GAS INC.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 63

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 At 2010 Rates							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,453	62.060%	6.836%	4.242%	$111,518
3	Unfunded Debt			76,982	2.930%	4.500%	0.132%	3,464
4	Common Equity			920,331	35.010%	7.529%	2.636%	69,292
5								
6		- Tab C-13, Schedule 9		$2,628,766	100.000%		7.010%	$184,274
7								
8	2011 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,631,453	62.060%	6.836%	4.242%	$111,518
10	Unfunded Debt		$76,982					
11	Adjustment, Revised Rates		4	76,986	2.930%	4.500%	0.132%	3,464
12	Common Equity			920,333	35.010%	8.470%	2.965%	77,952
13								
14		- Tab C-13, Schedule 9		$2,628,772	100.000%		7.339%	$192,934
15							(X-Ref - Tab C-13, Schedule 5)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
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Schedule 64

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855 *	$65,598	12.054%	$66,453	$8,010	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Apr-2010	1-Apr-2020	5.188%	100,000	1,000	99,000	5.318%	75,342	4,007	
12									-	-	
13											
14	LILO Obligations - Kelowna							5.905%	26,735	1,579	
15	LILO Obligations - Nelson							7.011%	4,258	299	
16	LILO Obligations - Vernon							8.150%	12,731	1,038	
17	LILO Obligations - Prince George							7.171%	32,685	2,344	
18	LILO Obligations - Creston							6.418%	3,098	199	
19											
20	Vehicle Lease Obligation							5.380%	12,740	685	
21											
22									$1,561,316	$107,269	
23											
24	Sub-Total								$1,561,316	$107,269	
25	Less - Fort Nelson Division Portion of Long Term Debt								(2,990)	(205)	
26	Total								$1,558,326	$107,064	
27								(X-Ref - Tab C-13, Schedule 10)	, (X-Ref - Tab C-13, Schedule 62)		
28	*Includes adjustment of $5,049 for BC Hydro Premium								Average Embedded Cost	6.870%	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 65

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855	$65,990 *	12.054%	$66,845	$8,057	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Apr-2010	1-Apr-2020	5.188%	100,000	1,000	99,000	5.318%	100,000	5,318	
12	2011 Medium Term Debt Issue- Series 26	1-Jul-2011	1-Jul-2021	5.650%	100,000	1,000	99,000	5.783%	50,411	2,915	
13											
14	LILO Obligations - Kelowna							5.919%	25,729	1,523	
15	LILO Obligations - Nelson							7.093%	4,110	292	
16	LILO Obligations - Vernon							8.242%	12,267	1,011	
17	LILO Obligations - Prince George							7.256%	31,571	2,291	
18	LILO Obligations - Creston							6.496%	2,996	195	
19											
20	Vehicle Lease Obligation							7.631%	13,455	1,027	
21											
22									$1,634,658	$111,737	
23											
24	Sub-Total								$1,634,658	$111,737	
25	Less - Fort Nelson Division Portion of Long Term Debt								(3,205)	(219)	
26	Total								$1,631,453	$111,518	
27								(X-Ref - Tab C-13, Schedule 11)	(X-Ref - Tab C-13, Schedule 63)		
28	*Includes adjustment of $7,772 for BC Hydro Premium								Average Embedded Cost	6.836%	

TERASEN GAS INC.

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 66

GROSS MARGIN RECONCILIATION WITH 2010 RATES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	2.961	69,174.3	$204,825	11.840	754,076	-1.20%	$105,858	-	-	$0	$310,683	$310,678	$5
4	Schedule 2 - Small Commercial	2.479	24,374.3	60,424	24.840	76,536	-4.54%	21,777	-	-	-	82,201.3	82,199.7	1.6
5	Schedule 3 - Large Commercial	2.136	16,818.6	35,925	132.520	5,022	-0.50%	7,945	-	-	-	43,869.8	43,869.5	0.3
6	Total Schedules 1 , 2 and 3		110,367.2	301,174		835,633		135,580		-	-	436,753.7	436,747.0	6.7
7														
8	Schedule 4 - Seasonal Service	0.762	184.6	141	439.000	16		83	-	-	-	224.1	247.9	(23.8)
9	Schedule 5 - General Firm Service	0.593	3,184.6	1,888	587.000	281		1,979	14.655	207	3,033	6,900.5	6,900.5	0.0
10														
11	Industrials													
12	Schedule 7 - Interruptible	0.990	22.7	22	880.000	2		21	-	-	-	43.6	44.0	(0.4)
13														
14	Schedule 6 - N G V Fuel - Stations	3.398	103.8	353	61.000	32		23	-	-	-	376.1	376.6	(0.5)
15														
16	Total Industrials		103.8	353		32		23		-	-	376.1	376.6	(0.5)
17														
18	Total Core Sales		113,862.9	303,578		835,964		137,666		207	3,033	444,298.0	444,316.0	(18.0)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.081	8,103.2	659.3	4,783.000	13		746	11.174	255.8	2,858.3	4,263.7	4,885.4	(621.7)
22	- Interruptible Service	0.739	11,080.5	8,190.3	3,742.000	22		988	-	14.5	-	9,178.2	9,078.6	99.5
23	Schedule 23 - Large Commercial	2.136	6,134.0	13,102	210.520	1,309		3,308	-	-	-	16,410.1	16,348.0	62.1
24	Schedule 25 - Firm Service	0.593	12,944.4	7,676	665.000	573		4,573	14.655	813	11,910	24,158.5	23,819.5	339.0
25	Schedule 27 - Interruptible Service	0.990	5,587.4	5,532	958.000	98		1,127	-	-	-	6,658.1	6,607.2	50.9
26														
27	Total T-Service		43,849.5	35,159		2,015		10,741		1,083	14,768	60,668.7	60,738.7	(70.0)
28														
29	Total Non-Bypass Sales & Transportation Service		157,712.4	338,737.2		837,979		148,407.4		1,290	17,800.9	504,966.7	505,054.7	(88.0)
30			(X-Ref - Tab C-13, Schedule 14)			(X-Ref - Tab C-13, Schedule 22)				(X-Ref - Tab C-13, Schedule 22 Columns 6 + 8, line 27)				

TERASEN GAS INC.

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 67

GROSS MARGIN RECONCILIATION WITH 2011 RATES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	3.066	68,578.9	$210,263	11.840	759,267	-1.20%	$106,586	-	-	$0	316,848.9	316,838.8	10.1
4	Schedule 2 - Small Commercial	2.557	24,603.1	62,910	24.840	77,252	-4.54%	21,981	-	-	-	84,891.4	84,899.5	(8.1)
5	Schedule 3 - Large Commercial	2.197	17,168.5	37,719	132.520	5,126	-0.51%	8,110	-	-	-	45,828.8	45,820.9	7.9
6	Total Schedules 1 , 2 and 3		110,350.5	310,892		841,644		136,677		-	-	447,569.1	447,559.2	9.9
7														
8	Schedule 4 - Seasonal Service	0.790	184.6	146	256.080	16		49	-	-	-	194.5	253.9	(59.4)
9	Schedule 5 - General Firm Service	0.611	3,184.3	1,946	587.000	281		1,979	15.134	207	3,132	7,056.8	7,061.3	(4.5)
10														
11	Industrials													
12	Schedule 7 - Interruptible	1.018	22.7	23	880.000	2		21	-	-	-	44.2	45.0	(0.8)
13														
14	Schedule 6 - N G V Fuel - Stations	3.485	103.8	362	61.000	32		23	-	-	-	385.2	385.6	(0.4)
15														
16	Total Industrials		103.8	362		32		23		-	-	385.2	385.6	(0.4)
17														
18	Total Core Sales		113,845.9	313,345		841,975		138,728		207	3,132	455,249.7	455,305.0	(55.3)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.083	8,103.2	675	4,783.000	13		746	11.618	256	2,972	4,393.4	4,998.4	(605.0)
22	- Interruptible Service	0.757	11,080.5	8,384	3,742.000	22		988	1.702	15	25	9,396.3	9,288.6	107.7
23	Schedule 23 - Large Commercial	2.197	6,177.2	13,571	210.520	1,318		3,331	-	-	-	16,901.9	16,845.4	56.5
24	Schedule 25 - Firm Service	0.611	12,944.1	7,909	665.000	573		4,573	15.134	813	12,299	24,780.6	24,373.3	407.3
25	Schedule 27 - Interruptible Service	1.018	5,587.4	5,688	958.000	98		1,127	-	-	-	6,814.6	6,760.2	54.4
26														
27	Total T-Service		43,892.4	36,227		2,024		10,764		1,083	15,296	62,286.9	62,265.9	21.0
28														
29	Total Non-Bypass Sales & Transportation Service		157,738.3	349,572.8		843,999		149,492.1		1,290	18,427.5	517,536.6	517,570.9	(34.3)
30			(X-Ref - Tab C-13, Schedule 15)			(X-Ref - Tab C-13, Schedule 24)					(X-Ref - Tab C-13, Schedule 24 Columns 6 + 8, line 27)			

EARNINGS SHARING CALCULATION - 2009
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Description	2009	Reference
	(1)	(2)	(3)
1	Utility rate base	$2,453,485	- Tab C-13, Schedule 74
2			
3	Common Equity Component (35.01%)	858,965	- Tab C-13, Schedule 75
4			
5			
6	Achieved ROE on Common Equity	11.41%	- Tab C-13, Schedule 75
7			
8	Authorized ROE on Common Equity	8.47%	
9			
10	ROE Surplus / (Deficit)	2.94%	
11			
12	After Tax Surplus Available for Sharing	$25,254	
13			
14			
15	Customers' 50% Share of Surplus (net-of-tax)	$12,627	(X-Ref - Tab C-13, Schedule 70)
16			
17			
18	**Customers' 50% Share of Surplus (pre-tax)**	**$18,038**	(X-Ref - Tab C-13, Schedule 70)

TERASEN GAS INC. June 15, 2009 Application Section C
Tab 13
Schedule 69

END-OF-TERM CAPITAL INCENTIVE MECHANISM
FOR THE YEARS ENDING DECEMBER 31, 2004 TO 2011
($000s)

Line. No.		Particulars	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009	2010	2011	2012	Reference
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	a)	Formula Base Capital Expenditure Spending (with Actual Customer adds)										
2		Customer Addition Driven CapEx	$24,283	$26,319	$21,896	$21,441	$20,133	$13,420				
3		Other Base Capital CapEx	67,361	69,090	70,588	72,278	73,595	74,850				
4		Total Base Capital Expenditures - Formula	91,644	95,409	92,484	93,719	93,728	88,270				
5												
6	b)	Actual Base Capital Expenditures										
7		Customer Addition Driven CapEx	$21,896	$25,194	$28,820	$28,903	$32,288	$25,428				
8		Other Base Capital CapEx	48,717	50,840	55,269	44,417	57,859	63,360				
9		Total Base Capital Expenditures - Actual	70,613	76,034	84,089	73,320	90,147	88,788				
10												
11	c)	Capital Incentive	$21,031	$19,375	$8,395	$20,399	$3,581	($518)				
12		Cumulative Capital Incentive for Phase-Out	$21,031	$40,406	$48,801	$69,200	$72,781	$72,263				
13												
14	d)	Capital Incentive @ 14%	$2,944	$5,657	$6,832	$9,688	$10,189	$10,117				
15												
16		Customer Portion (50/50 during term. Total benefit less Phase-Out after)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$6,745	$8,431	$10,117	
17												
18		Company Portion (50/50 during term. 2/3 & 1/3 Phase-Out in 2010 and 2011)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$3,372	$1,686	$0	
19												
20									(X-Ref - Tab C-13, Schedule 70)			

TERASEN GAS INC. June 15, 2009 Application Section C
Tab 13
Schedule 70

CALCULATION OF EARNING SHARING MECHANISM (RIDER 3)
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2011
($000s)

Line No.	Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	TOTAL Volumes (TJ)	2010 Margin ($000s)	2011 Margin ($000s)	TOTAL Margin ($000s)	2010 True-up & Res Amortization ($000s)	2010 & 2011 ESM Amortization ($000s)	2010 & 2011 Capital Incentive Amortization ($000s)	2010 ESM Unit Rider ($/GJ)	2011 ESM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Earnings Sharing Mechanism (ESM) Rider 3 Calculation**											
2												
3												
4	**Non-Bypass**											
5	Rate 1 - Residential	67,829.2	67,190.5	135,019.7	$ 306,966	$ 305,757	$612,724	($304)	($7,715)	$2,232	($0.040)	($0.046)
6	Rate 2 - Small Commercial	24,374.3	24,603.1	48,977.4	82,200	82,972	165,171	(83)	(2,081)	599	($0.029)	($0.034)
7	Rate 3 / 23 - Large Commercial	22,952.6	23,345.7	46,298.3	60,218	61,243	121,461	(60)	(1,529)	441	($0.023)	($0.027)
8	Rate 4 - Seasonal Service	184.6	184.6	369.2	248	248	496	-	(6)	2	($0.011)	($0.011)
9	Rate 5 / 25 - General Firm Service	15,565.0	15,470.1	31,035.1	30,469	30,413	60,882	(30)	(767)	222	($0.017)	($0.020)
10	Rate 6 - NGV	103.8	103.8	207.6	377	377	753	-	(9)	3	($0.024)	($0.033)
11	Rate 7 / 27 - Interruptible	5,197.7	5,186.1	10,383.8	6,258	6,247	12,505	(6)	(157)	45	($0.010)	($0.012)
12	Rate 22 - Large Industrial Transportation	11,579.4	11,560.2	23,139.6	9,332	9,318	18,651	(9)	(235)	68	($0.007)	($0.008)
13	Rate 22A - Inland	4,904.7	4,904.7	9,809.4	3,920	3,920	7,841	(4)	(99)	29	($0.007)	($0.008)
14	Rate 22B - Elkview Coal	646.1	646.1	1,292.2	112	112	224	-	(3)	1	$0.000	($0.002)
15	Rate 22B - All Other	1,856.3	1,856.3	3,712.6	1,037	1,037	2,075	(1)	(26)	8	($0.005)	($0.005)
16												
17	**Total Non-Bypass**	155,193.7	155,051.2	310,244.9	$501,138	$501,645	$1,002,783	($497)	($12,627)	$3,650 [1]		
18		(X-Ref - Tab C-13, Schedule 22; - Tab C-13, Schedule 24)										

19

20 Note 1:

21 Terasen Gas is projecting a 2009 return on equity of 11.41%, which is 2.94% higher than
22 the allowed ROE of 8.47%. Under the earnings sharing mechanism, Terasen Gas is to share
23 equally with its customers, earnings variances between the authorized level of earnings as
24 determined annually under the settlement and the actual earnings of the utility. Accordingly,
25 customer's portion of the 2009 earnings surplus is $18.038 million. The detailed calculations
26 for 2009 are as follows:

27

28 After Tax surplus available for sharing = $858.965 million x (11.41% - 8.47%) = $25,254 million
29 Customers' 50% share (Net-of-Tax) = $12.627 million
30 Customers' 50% share (Pre-Tax) = $18.038 million

Line No.		Amortization Period	2010 Pre-Tax	2010 Net-Of-Tax	2011 Pre-Tax	2011 Net-Of-Tax	Total Pre-Tax	Total Net-Of-Tax	
31									
32	The total amortization balance of $13.690 is made up of:								
33	2008 true-up ($12.029m per '07 A/Review, $12.739m per '08 A/Rpt)	2011	$710	$508	$0	$0	$710	$508	
34	Tax Adjustment on 2008 ESM True Up		(15)	(11)			(15)	(11)	
35			695	497	-	-	695	497	(Column 8, Line 17)
36									
37	2009 pre-tax Customers' 50% share	2010 and 2011	9,036	6,461	9,003	6,617	18,039	13,078	
38	Tax Adjustment on 2009 ESM		(190)	(136)	(429)	(315)	(618)	(451)	(Column 9, Line 17)
39			8,846	6,325	8,574	6,302	17,420	12,627	(X-Ref - Tab C-13, Schedule 68)
40									
41	2009 End Of Term Capital Incentive Mechanism	2010 and 2011	(3,372)	(2,411)	(1,686)	(1,239)	(5,058)	(3,650)	(Column 10, Line 17)
42									(X-Ref - Tab C-13, Schedule 69)
43	Total Balance - Refund to Customers in 2010 and 2011		$6,169	$4,411	$6,888	$5,063	$13,057	$9,474	(X-Ref - Tab C-13, Schedule 54; Schedule 55 line 39, columns 8 & 9)

TERASEN GAS INC. June 15, 2009 Application Section C
Tab 13
Schedule 71

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	2010 Amortization ($000s)	2011 Amortization ($000s)	2010 Amortization of RSAM Unit Rider ($/GJ)	2011 Amortization of RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**RSAM (Rider 5) Calculation**						
2							
3	Rate 1 - Residential	67,829.2	67,190.5			($0.053)	($0.052)
4	Rate 2 - Small Commercial	24,374.3	24,603.1			($0.053)	($0.052)
5	Rate 3 - Large Commercial	16,818.6	17,168.5			($0.053)	($0.052)
6	Rate 23 - Large Commercial Transportation	6,134.0	6,177.2			($0.053)	($0.052)
7		115,156.1	115,139.3	($6,156)	($5,990) (1)		
8			(X-Ref - Tab C-13, Schedule 54; - Tab C-13, Schedule 55,sum of lines 6 & 7 and columns 8 & 9)				

10 Note 1: RSAM Rider Change

12 Terasen Gas forecasts that there will be approximately -$5.6 million (net-of-tax) of RSAM additions by the end of
13 2009. After offsetting the 2009 RSAM Rider recovery, the RSAM account including interest is now projected to be a
14 credit balance of $13,204,000 on a net-of-tax basis by the end of 2009. In accordance with the 2004-2009 Extended
15 PBR Settlement, the RSAM balance is to be amortized over three years. Accordingly, the net-of-tax RSAM balance to
16 be amortized in 2010 is a credit of $4,402,000. On a pre-tax basis, this amounts to $6,156,000 or a refund to the
17 customer of $0.053/GJ, which is a $.054 reduction from the existing charge of $0.001/GJ. The corresponding 2011
18 refund to the customer is $0.052/GJ.

20 2010 Net-Of-Tax Amortization = 1/3 of Projected December 31, 2009 RSAM Balance
21 = 1/3 * ($-13,166 RSAM + $-38 RSAM Interest)
22 = 1/3 * $-13,204
23 = $-4,402 Net-of-tax amortization

25 2010 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
26 = $-4,402 / (1 - 28.5%)
27 = $-6,156

29 2011 Net-of-Tax Amortization = 1/2 of Projected December 31, 2010 RSAM Balance
30 = 1/2 * ($-8,777 RSAM + $-29 RSAM Interest)
31 = 1/2 * $-8,806
32 = $-4,402 Net-of-tax amortization

34 2011 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
35 = $-4,402 / (1 - 26.5%)
36 = $-5,990

TERASEN GAS INC.

June 15, 2009 Application

Section C
Tab 13
Schedule 72

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 ----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	108,575	115,723	-	115,723	7,148	
3	Transportation	85,478	89,214	-	89,214	3,736	
4		194,053	204,937	-	204,937	10,884	
5							
6	Average Rate per GJ						
7	Sales	$14.892	$11.902	$0.000	$11.902	($2.990)	
8	Transportation	$0.848	$0.830	$0.000	$0.830	($0.018)	
9	Average	$8.706	$7.000	$0.000	$7.000	($1.706)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,591,039	$1,377,376	$0	$1,377,376	($213,663)	
13	- Increase / (Decrease)	25,852	-	-	-	(25,852)	
14	RSAM Revenue		(17,004)	-	(17,004)	(17,004)	
15	Transportation - Existing Rates	68,993	74,087	-	74,087	5,094	
16	- Increase / (Decrease)	3,535		-	-	(3,535)	
17	**Total**	1,689,419	1,434,459	-	1,434,459	(254,960)	
18							
19	Cost of Gas Sold (Including Gas Lost)	1,187,999	931,546	-	931,546	(256,453)	
20							
21	**Gross Margin**	501,420	502,913	-	502,913	1,493	
22							
23	Operation and Maintenance	173,138	165,162	-	165,162	(7,976)	- Tab C-13, Schedule 28
24	Vehicle Lease	1,804	1,804	-	1,804	-	- Tab C-13, Schedule 28
25	Property and Sundry Taxes	47,593	47,593	-	47,593	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	89,685	79,725	-	79,725	(9,960)	- Tab C-13, Schedule 33
27	Other Operating Revenue	(23,444)	(20,906)	-	(20,906)	2,538	- Tab C-13, Schedule 26
28		288,776	273,378	-	273,378	(15,398)	
29	Utility Income Before Income Taxes	212,644	229,535	(1)	229,535	16,891	
30							
31	Income Taxes	26,331	23,010	1	23,010	(3,321)	
32							
33	**EARNED RETURN**	$186,313	$206,525	$0	$206,525	$20,212	(X-Ref - Tab C-13, Schedule 73)
34							
35							
36	**UTILITY RATE BASE**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	- Tab C-13, Schedule 74
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.33%	8.42%		8.42%	1.09%	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 ----Revised Rates----- Revised Revenue	2009 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,313	$206,525	$0	$206,525	$20,212	- Tab C-13, Schedule 72
3	Deduct - Interest on Debt	(110,953)	(108,525)	-	(108,525)	2,428	- Tab C-13, Schedule 75
4	Add- Non-Tax Ded. Expense (Net)	328	428	-	428	100	
5							
6	Accounting Income After Tax	75,688	98,428	-	98,428	22,740	
7	Add (Deduct) - Timing Differences	(14,248)	(44,736)	-	(44,736)	(30,488)	- Tab C-13, Schedule 37
8							
9	Taxable Income After Tax	$61,440	$53,692	$0	$53,692	($7,748)	
10							
11		30.000%	30.000%	30.000%	30.000%	0.000%	
12	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
13							
14	Taxable Income	$87,771	$76,703	$0	$76,703	($11,068)	
15							
16	**Total Income Tax**	$26,331	$23,011	$0	$23,011	($3,320)	
17							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 Adjustments	2009 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,339,098	$3,215,664	$0	$3,215,664	($123,434)	
2	Adjustment - CPCNs	12,855	12,879	-	12,879	24	
3	Gas Plant in Service, Ending	3,442,274	3,317,590	-	3,317,590	(124,684)	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($808,588)	($743,486)	$0	($743,486)	$65,102	
6	Accumulated Depreciation Ending - Plant	(869,177)	(779,187)	-	(779,187)	89,990	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($148,423)	($161,636)	$0	($161,636)	($13,213)	
9	CIAC, Ending	(146,828)	(176,845)	-	(176,845)	(30,017)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$46,175	$45,381	$0	$45,381	($794)	
12	Accumulated Amortization Ending - CIAC	44,846	44,146	-	44,146	(700)	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,456,116	$2,387,253	$0	$2,387,253	($68,863)	
15							
16							
17	Adjustment to 13-Month Average	-	(10,554)	-	(10,554)	(10,554)	
18	Work in Progress, No AFUDC	15,773	15,627	-	15,627	(146)	
19	Unamortized Deferred Charges*	(32,644)	(25,545)	-	(25,545)	7,100	- Tab C-13, Schedule 76
20	Cash Working Capital	(33,719)	(27,183)	-	(27,183)	6,536	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	138,198	115,701	-	115,701	(22,497)	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	-	278,048	-	278,048	278,048	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(552)	(278,048)	-	(278,048)	(277,496)	- Tab C-13, Schedule 61
24	LILO Benefit	(1,814)	(1,814)	-	(1,814)	-	
25	**Utility Rate Base**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	(X-Ref - Tab C-13, Schedule 68, Schedule 72,Schedule 75)

*Not equal to Schedule 8, column (2), line 19 because of differences in MCRA, CCRA and ESM balances for ESM calculation purposes

TERASEN GAS INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2009 RATES							
2	Long-Term Debt			$1,504,299	62.36%	6.959%	4.34%	
3	Unfunded Debt			90,221	2.63%	4.250%	0.11%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			858,965	35.01%	11.740%	4.11%	
6								
7		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.56%	
8								
9	2009 REVISED RATES							
10	Long-Term Debt			$1,504,299	61.31%	6.959%	4.27%	$104,691
11	Unfunded Debt		$90,221					
12	Adjustment, Revised Rates		-	90,221	3.68%	4.250%	0.16%	3,834
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			858,965	35.01%	11.409%	3.99%	97,999
15		(X-Ref - Tab C-13, Schedule 72)						
16		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.42%	$206,525

TERASEN GAS INC. August 17, 2009 Revised Section C
Tab 13
Schedule 76

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2009	Mid-Year Average 2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	($23,164.7)	$602.9	($180.9)	$422.0	$0.0	$0.0	$0.0	($22,742.7)	($22,953.7)
3	CCRA Interest	(596.2)	(428.2)	128.5	(299.7)	-	-	-	(895.9)	(746.1)
4	Midstream Cost Reconciliation Account (MCRA)	(23,588.7)	85,731.4	(25,719.4)	60,012.0	-	-	-	36,423.3	6,417.3
5	MCRA Interest	(1,812.2)	47.2	(14.2)	33.0	-	-	-	(1,779.2)	(1,795.7)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,917.2)	(7,902.9)	2,370.9	(5,532.0)	-	405.1	(121.5)	(13,165.6)	(10,541.4)
7	RSAM Interest	35.3	(133.2)	40.0	(93.2)	-	27.8	(8.3)	(38.4)	(1.6)
8	Revelstoke Propane Cost Deferral Account	(477.8)	627.1	(188.1)	439.0	-	-	-	(38.8)	(258.3)
9	SCP Mitigation Revenues Variance Account	(4,539.0)	(981.7)	324.5	(657.2)	1,078.1	-	-	(4,118.1)	(4,328.6)
10	SCP West to East Transmission	(1,658.0)	(376.1)	124.7	(251.4)	371.2	-	-	(1,538.2)	(1,598.1)
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	1,205.0	8,002.0	(2,400.6)	5,601.4	(436.2)	-	-	6,370.2	3,787.6
14	NGV Conversion Grants	124.0	80.0	(24.0)	56.0	(43.1)	-	-	136.9	130.5
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(732.0)	(700.0)	210.0	(490.0)	478.2	-	-	(743.8)	(737.9)
18	Insurance Variance	(259.0)	(479.5)	143.9	(335.6)	(91.4)	-	-	(686.0)	(472.5)
19	Pension & OPEB Variance	207.0	(581.4)	-	(581.4)	(312.0)	-	-	(686.4)	(239.7)
20	BCUC Levies Variance	(295.0)	(383.7)	115.1	(268.6)	301.6	-	-	(262.0)	(278.5)
21	Interest Variance	(1,629.0)	(790.1)	237.0	(553.1)	(50.1)	-	-	(2,232.2)	(1,930.6)
22	Interest Variance - Funding benefits via Customer Deposits	161.0	76.9	(23.1)	53.8	(0.6)	-	-	214.2	187.6
24	Olympics Security Costs Deferral	-	746.9	(224.1)	522.8	-	-	-	522.8	261.4
25	IFRS Conversion Costs	98.0	430.7	(129.2)	301.5	-	-	-	399.5	248.8
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$0.0	$630.0	($189.0)	$441.0	$0.0	$0.0	$0.0	$441.0	$220.5
29	2010-2011 Revenue Requirement Application	55.0	1,057.5	(317.3)	740.2	-	-	-	795.2	425.1
30	CCE CPCN Application	-	270.0	(81.0)	189.0	-	-	-	189.0	94.5
31										-
32	Other									-
33	IFRS Transitional Adjustments	-	-	-	-	-	-	-	-	-
34	OPEB Funding	(28,644.0)	(5,582.6)	1,674.8	(3,907.8)	-	-	-	(32,551.8)	(30,597.9)
35	Pension & OPEB Funding	-	-	-	-	-	-	-	-	-
36										-
37	Residual Deferred Charges									-
38	SCP Tax Reassessment	7,292.8	165.0	(49.5)	115.5	-	-	-	7,408.3	7,350.6
39	Deferred Service Line Installation Fee	-	1,442.9	-	1,442.9	-	-	-	1,442.9	1,442.9
40	Earnings Sharing Mechanism	(9,879.1)	(18,748.0)	5,624.4	(13,123.6)	-	14,113.0	(4,233.9)	(13,123.6)	(11,501.4)
41	CCT Assessment	(16.0)	-	-	-	13.5	-	-	(2.5)	(9.3)
42	Carbon Tax Implementation	103.0	-	-	-	(198.0)	-	-	(95.0)	4.0
43	TGS Amalgamation	132.0	-	-	-	-	-	-	132.0	132.0
44	TGS O&M Variance	233.0	170.0	(51.0)	119.0	-	-	-	352.0	292.5
45	Carbon Tax Cost of Service	(384.0)	326.0	(97.8)	228.2	111.8	-	-	(44.0)	(214.0)
46	OSC Certification Compliance	90.0	110.7	(33.2)	77.5	(76.4)	-	-	91.1	90.6
47	Bad Debt Allowance for Rates 14 & 14A	(114.0)	(26.6)	0.4	(26.2)	-	-	-	(140.2)	(127.1)
48	2005 ROE Hearing	150.0	-	-	-	(150.0)	-	-	-	75.0
49	2006 LCT Elimination	14.0	-	-	-	(14.0)	-	-	-	7.0
50	NGV Compression Equipment Recovery	249.0	-	-	-	(249.0)	-	-	-	124.5
51	SCP PG&E Contract Cancellation	661.8	-	-	-	(661.8)	-	-	-	330.9
52										
53										
54	Total Deferred Charges for Rate Base	($94,895.0)	$63,403.2	($18,728.2)	$44,675.0	$71.8	$14,545.9	($4,363.7)	($39,966.0)	($66,709.1)
55										

Line No.							
56	Reconciliation with Mid Year Deferred Charges for ESM calculation:						
57							
58	Less:			Add:			
59	Projected Mid Year MCRA balance (+ interest)	4,621.6		Approved Mid Year MCRA balance (+ interest)	7,961.3		
60	Projected Mid Year CCRA balance (+ interest)	(23,699.8)		Approved Mid Year CCRA balance (+ interest)	(12,224.5)		
61	Projected Mid Year Revelstoke Propane balance	(258.3)		Approved Mid Year Revelstoke Propane balance	16.7		
62	Projected Mid Year ESM balance	(11,501.4)		Approved Mid Year Approved balance	3,916.2		
63	Projected Mid Year RSAM balance (+ interest)	(10,543.0)	(41,380.9)	Approved Mid Year RSAM balance (+ interest)	113.7	(216.6)	
64							
65				Net Mid-Year Reconciling items for ESM purposes			41,164.3
66				Mid Year Deferred Charges balance for ESM purposes			($25,544.8)
67							(X-Ref - Tab C-13, Schedule 74)
68							

Terasen Gas Inc. 2010-2011 Revenue Requirements Application
Negotiated Settlement Process
Issues of Particular Concern to the Commission Panel

In accordance with sections 3 and 9 of the Negotiated Settlement Process-Policy, Procedures and Guidelines, the Commission Panel has identified the following issues of particular concern that parties should be aware of during the negotiations:

1. EEC Program-TGI is to provide results of the programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding.

2. Natural Gas for Vehicles ("NGV")-if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?

3. Biogas-to be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost.

4. International Financial Reporting Standards ("IFRS")-no IFRS impact in 2010.

5. 2010 Rate Changes-in the event that a 2010 rate reduction were to occur as a result of the negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability.

6. CPCN threshold-stay at $5million.

7. Unrealized losses in rate base-should some of these losses be to the shareholder? Parties should present a separate settlement package.

The
British Columbia
Public Interest
Advocacy Centre

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Valerie Conrad	687-3017
Sarah Khan	687-4134
Eugene Kung	687-3006
James L. Quail	687-3034
Ros Salvador	488-1315
Leigha Worth	687-3044

Barristers & Solicitors

Peggy Lee
Article Student

Our file: 7432

November 12, 2009

VIA EMAIL

Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Terasen Gas Inc. Revenue Requirements 2010-2011
Negotiated Settlement

This is to confirm that we are satisfied that the draft Settlement Agreement circulated by Mr. Thompson and Mr. Loski on November 5, 2009 accurately captures the consensus reached by the parties to the Negotiated Settlement Process in this proceeding, and that we have been instructed by our clients, BCOAPO et al., to endorse it.

Accordingly, we ask that the Commission incorporate it into a consent Order for the resolution of all issues in the Application.

Our only further comments, made here only "for the record" and in no way detracting from our clients' endorsement of the Settlement, concern the “Alternative Energy Solutions" addressed under heading 13 of the document. While we believe that the ultimately appropriate corporate and regulatory formats for these lines of business are subject-matters which may require eventual determination by the Commission, our clients are content with the treatment of these issues in the Settlement Agreement over its term, in that it provides a “firewall” to ensure that the utility’s natural gas distribution customers do not subsidize or otherwise contribute to these nascent programs through their rates.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by:

Jim Quail
Executive Director

cc: parties of record

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E-mail: cweafer@owenbird.com
Our File: 23841/0040

November 13, 2009

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. ("Terasen") 2010 and 2011 Revenue Requirements and Delivery Rates Application, Project No. 3698562

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). We confirm that the CEC accepts the terms of the final version of the Negotiated Settlement Agreement on the above-noted Application circulated by Terasen on November 5, 2009 and have no comments on that draft.

The CEC thanks the Commission staff and facilitator, Terasen and the other customer representatives for their efforts during these negotiations.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: CEC
cc: Terasen
cc: Registered Intervenors

November 13, 2009

Mr. Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

RE: Negotiated Settlement Terasen Gas Inc. (TGI) Revenue Requirements Settlement 2010/2011

Dear Mr. Nakoneshny:

On November 5, 2009, TGI forwarded a Draft Agreement and requested that edits and comments be forwarded to TGI. Ministry of Energy, Mines and Petroleum Resources staff have reviewed the Draft Agreement and from a policy perspective, have an interest in 5 items:

11. Energy Efficiency and Conservation ("EEC") Funding for 2010
12. EEC Funding for 2011
13. Alternative Energy Solutions
14. Natural Gas for Vehicles
15. Biogas

Other components of the negotiated settlement such as capital cost structure, interest rates, depreciation rates, salvage values, etc., are outside the purview of the Ministry's interests in this agreement. However, we note that, in the future, Use per Customer Rates (8) and Industrial Demand Forecast (9) may be lower depending on the implementation of TGI's EEC programs.

The 2007 Energy Plan and Climate Action Plan, 2008 amendments to the *Utilities Commission Act,* Ministerial Order B.C. Reg. 326/2008, and the Ministry's involvement in the 2008/09 TGI/TGVI Energy Efficiency and Conservation Application indicate the Province's intent to require electric and natural gas utilities to pursue energy efficiency.

The Ministry is particularly pleased with the reallocation of funds for low income and rental housing programs to $2.4 million for 2010 and 2011. The Ministry also appreciates the increase in industrial energy efficiency program funding in 2011.

We believe there is great potential for a significant amount of this industrial funding to be applied collaboratively with existing demand side management programs at electric utilities, especially at BC Hydro, in order to minimize duplication of structural costs and to maximize energy savings benefits at industrial facilities.

Appropriate oversight of EEC funding is maintained through the TRC requirements and annual reporting to the Commission. As a result, the Ministry supports Option 12.1 (a) and (b) to maintain program continuity and effectiveness.

Alternative Energy Solutions is a new type of service that TGI proposes to offer to existing and new customers. Geo-exchange, solar-thermal and district energy systems offer the potential to reduce greenhouse gas emissions, and as such, the Ministry is encouraged that TGI is proposing to offer this new type of service.

The Ministry supports the expanded use of natural gas for vehicles (NGV) and biogass, and is encouraged that TGI intends to apply to the Commission for appropriate rates.

Sincerely,

Paul Wieringa
Executive Director
Renewable Energy and Energy Efficiency Branches
Ministry of Energy, Mines and Petroleum Resources
Telephone: 250-952-0243
Facsimile: 250-952-0258

From: Nakoneshny, Philip BCUC:EX
Sent: Friday, November 13, 2009 12:59 PM
To: Commission Secretary BCUC:EX
Subject: FW: Terasen Gas -Revenue Requirements-Negotiated Settlement

-----Original Message-----
From: Dave Newlands [mailto:dnewlands@telus.net]
Sent: Friday, November 13, 2009 9:40 AM
To: 'Al Kleinschmidt'; Brownell, Bob BCUC:EX; Bystrom, Chris; Chris Weafer; J. David Newlands; Roy, Diane; David Craig (dwcraig@allstream.net); Domingo, Yolanda BCUC:EX; Stout, Douglas; 'Eugene Kung'; 'Frederick Metcalfe'; 'Leigha Worth'; McMahon, Claudia BCUC:EX; Carman, Michelle; Nakoneshny, Philip BCUC:EX; 'Paul Cassidy'; Hill, Shawn; Loski, Tom; Wieringa, Paul EMPR:EX; Ghikas, Matt; Sue, Suzanne BCUC:EX; Thomson, Scott - TGI; James L. Quail (JimQuail@bcpiac.com)
Cc: Bernadet Mark SPO
Subject: Terasen Gas -Revenue Requirements-Negotiated Settlement

Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

Dear Philip

Terasen Gas Revenue Requirements Application-2010/2011
Negotiated Settlement

I write on behalf of Teck Coal.

Teck Coal participated in the Negotiated Settlement Process ("NSP"),facilitated by the Staff of the British Columbia Utilities Commission, and held in the offices of the Commission ,which commenced on October 21,2009.

Teck Coal in the negotiations took into consideration the 7 "Issues of Particular Concern to the Commission Panel ",as provided by the Commission Panel at the commencement of the negotiation.

Issue Number 5 stated " 2010 Rate Changes- in the event that a 2010 rate reduction were to occur as a result of the negotiations ,the current rates should remain unchanged and place the revenue surplus into a deferred account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability"

Teck Coal supports the Negotiated Settlement Agreement Package ("TGI NSP Agreement Package ") dated and circulated by Terasen Gas Inc incorporating a decrease of (1.73%) in the Fiscal Year commencing January 1,2010,previously an increase of 5.3%.and an increase of 3.93% in the Fiscal Year Commencing January 1,2011,previously an increase of 4.1% .

The Negotiated Settlement Agreement Package, incorporates ,amongst others,Issues of Particular Concern to the Commission Panel No. 5

Teck Coal recognizes and emphasizes that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agreed that any compromises resulting from this Agreement are without prejudice to the Parties[1] ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

Yours Truly

J.David Newlands

Cc Mark Bernadet ,General Manager ,Business Improvement,Teck Coal

PHILIP W. NAKONESHNY
DIRECTOR, RATES AND FINANCE
Philip.Nakoneshny@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
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BC TOLL FREE: 1-800-663-1385
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November 13, 2009

Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: Terasen Gas Inc.
2010 and 2011 Revenue Requirements Application
Negotiated Settlement Agreement
Letter of Comment

Commission staff participated in the settlement discussions that led to a Negotiated Settlement Agreement ("Settlement Agreement") being reached between Terasen Gas Inc. ("Terasen Gas") and the registered Intervenors (collectively, the "Parties") in accordance with the *Negotiated Settlement Process-Policy, Procedures and Guidelines, January 2001* ("NSP Guidelines"). Commission staff has informed the Parties that the agreements reached on certain issues were not supported by Commission staff and that Commission staff intended to submit a Letter of Comment in respect of those issues. The Parties agreed to Commission staff adopting that course.

There are three items in the Settlement Agreement that Commission staff do not support:

1. Item 10-Inclusion of SCP Capacity in MCRA

Commission Order G-98-05 states that:
"The Commission approves the debiting of the annual charge of $3.6 million (based on the monthly instalments) against the Midstream Cost Reconciliation Account, with an equal and offsetting amount to be credited to the delivery margin the revenue account for a limited period as a unique and unusual transaction in the circumstances of the SCP and the termination of the BC Hydro TSA. The debiting and the crediting will commence on either November 1, 2005 or January 1, 2006, as consistent with the amount of the BC Hydro/Terasen Inc. TSA revenue that Terasen Gas forecast in its Annual Review submission for 2005 and will end on the earlier of the November 1, 2010 or such other date as the Commission may determine."

The Settlement Agreement continues to include the annual charge of $3.6 million against the MCRA with an offsetting credit to the delivery margin. In Commission staff's view, extending this treatment beyond November 1, 2010 as contemplated by Order G-98-05 requires a determination by the Commission Panel.

Commission staff accepts that such determination will occur if the Commission Panel approves the Settlement Agreement.

2. Item 13-Alternative Energy Solutions

Terasen Gas added 9 enhanced sales and business development staff in 2009 estimated to cost $1.35 million and proposes increases of $3.0 million in 2010 for an additional 10 enhanced sales and business development staff including $1.1 million for consultants and studies and a further $0.6 million in 2011 for 4 enhanced sales and business development staff (BCUC IR 1.72.2 and IR 2.96.2 to 2.96.4; IR 1.114.7). The number of customers are expected to increase between 1.0 to 1.1 percent from 2009 to 2011, but the level of spending in Customer Solutions and Services increases by 17 percent, 27 percent and 8 percent respectively from 2009 to 2011 (BCUC IR 1.96.3).

The New Energy Solutions Deferral Account is to capture direct costs, sales and marketing O&M and other development costs by timesheets or other direct charge and an overhead allocation. In Commission staff's view, due to the modest growth in customer additions from 2009 to 2011, the additional enhanced sales and business development staff were primarily hired in 2009 to 2011 to develop and market Alternative Energy Solutions. The use of timesheets, direct charges and overhead allocations may result in a proper reallocation of costs from the gas utility to the New Energy Solutions Deferral Account.

The down time or idle time that will likely be experienced while the Alternative Energy is being marketed may not be captured by the timesheet allocation and could remain as a cost to the gas utility. In Commission staff's view, it would be preferable to directly charge the fully loaded cost of the additional enhanced sales and business development staff and the costs of consultants and studies to the New Energy Solutions Deferral Account to avoid any of these costs being borne by natural gas customers.

If Terasen Gas is able to demonstrate that the use of timesheets, direct charges and overhead allocations would result in none of the costs that are incurred for Alternative Energy Solutions including down time and the costs of consultants and studies to be borne by gas customers, then Commission staff's concern is addressed.

3. Item 14-Natural Gas for Vehicles ("NGV")

Terasen Gas proposes to treat as general O&M, rather than track separately, NGV marketing and project development costs incurred prior to signing a contract with a customer for compression and refuelling service (BCUC IR 1.21.1).

Commission staff attempted to obtain information on the NGV marketing costs that are currently incurred through information requests, but were unsuccessful. In Commission staff's view, information on the incremental marketing costs being incurred will be required if Terasen Gas, during 2010 and 2011, applies

…/3

for approval of Rate Schedule 6 C NGV Compression and Refuelling Service and 6A NGV Refuelling Service , including recovery of the incremental marketing costs, and the Commission is to review the applications on a case-by-case basis as contemplated in the Settlement Agreement.

Yours truly,

Original Signed by

Philip W. Nakoneshny
Director, Rates and Finance

Terasen Gas

Tom A. Loski
Chief Regulatory Officer

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Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

November 13, 2009

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

Attention: Mr. Philip Nakoneshny, Director, Rates and Finance

Dear Mr. Nakoneshny:

Re: Terasen Gas Inc. ("Terasen Gas")
2010 and 2011 Revenue Requirements Application
Negotiated Settlement Agreement

On June 15, 2009, Terasen Gas filed its 2010 and 2011 Revenue Requirements Application, which was supplemented by a filing on July 9, 2009 and amended by filings on August 14 and September 18, 2009 (the "Application").

In accordance with Commission Order No. G-76-09 issued on June 19, 2009, a Workshop was held on July 6, 2009 for a review of the Application, a Procedural Conference was held on July 15, 2009, and Terasen Gas responded to two rounds of Information Requests. In accordance with Commission Order No. G-89-09 issued on July 20, 2009, a second Procedural Conference was held on September 25, 2009 and on October 2, 2009, the Commission issued Order G-119-09 establishing a Negotiated Settlement Process ("NSP") for the Application. In accordance with Order No. G-120-09, the NSP commenced on Wednesday, October 21, 2009 and concluded on Wednesday, November 4, 2009.

Terasen Gas has reviewed the attached settlement documents, including the Negotiated Settlement Agreement and associated financial schedules (collectively the "Negotiated Settlement") arising from the NSP. Terasen Gas recognizes the Negotiated Settlement as being the product of good faith compromises among parties with diverse interests in the issues raised by the Application. The Parties have expressly considered the Commission Panel's Issues. In fulfilling their role pursuant to the Commission's Negotiated Settlement Process Policy, Procedures and Guidelines (the "Guidelines"), Commission Staff made additional information available to the parties which they believed was in the public interest. The parties considered all such information in reaching the compromise Settlement Agreement and Terasen Gas considers the resulting Negotiated Settlement to be fair, just and reasonable. As the Negotiated Settlement represents compromises among the parties and an overall balance of interests, Terasen Gas stresses that the Negotiated Settlement should be considered as a package, with no part being severed unless otherwise stated in the Agreement. On that basis, Terasen Gas accepts the Negotiated Settlement.

Commission Staff have provided written comment on the NSP, and TGI responds to those comments below.

Inclusion of Southern Crossing Pipeline ("SCP") Capacity in the Midstream Cost Reconciliation Account ("MCRA"): TGI notes for reference that the evidence on the inclusion of the SCP costs in the MCRA is found in the Application on pages 314 to 315 and its response to BCUC IRs 1.68.1 and 2.92.1-7. The result of taking the approach in the Agreement is a lower delivery rate, all else equal, with an offsetting charge to the MCRA.

Alternative Energy Solutions (Geothermal/District Energy Systems and Solar Thermal): Staff's position on this issue turns on its view that, *"due to the modest growth in customer additions from 2009 to 2011, the additional enhanced sales and business development staff were primarily hired in 2009 to 2011 to develop and market Alternative Energy Solutions."* While that may be Staff's position, it is at odds with TGI's evidence. Staff's conclusion appears to rest on the notion that TGI could not truly require additional staff for marketing if there is only modest growth in customer additions, i.e. that there is a linear correlation between marketing effort and customer additions. TGI's evidence was that the competitive factors facing the gas business mean that it is necessary to invest more to maintain and grow the business, including the gas business.

Staff also identifies an issue relating to overhead allocation to the alternative energy class of service, so as to ensure gas customers are not bearing costs attributable to the pursuit of geothermal, solar thermal and district energy systems. The cost allocation methodology outlined in the Agreement is structured to avoid cross subsidization by gas customers. The Agreement contemplates a $500,000 annual overhead allocation to alternative energy solutions, and a corresponding reduction in overhead allocated to gas customers. This is a direct benefit to gas customers. As a point of comparison, the allocation of overhead to alternative energy solutions is approximately two times the allocation to Terasen Gas (Whistler) Inc., suggesting that the issue of overhead allocation is addressed adequately. The risk of non-recovery lies with TGI's shareholder, not gas customers. Notably, the gas customers themselves have endorsed the Agreement.

NGV Marketing Costs: TGI notes that it has an existing NGV tariff and the amount of NGV marketing costs in the revenue requirements for 2010 and 2011 is very modest (see TGI's responses to BCUC IR 1.21.2 (last paragraph) and BCUC IR 2.96.2). Issues relating to NGV have been deferred by the terms of the Settlement Agreement. TGI respectfully submits that there is no need for the Panel to address Staff's issue at this time.

TGI wishes to make one final comment relating to our procedural concerns regarding the publication of Staff's comments. Commission Staff unquestionably plays an important role during the confidential settlement discussions in providing information and assisting the parties, and providing a perspective regarding their view on the public interest. That role is one sanctioned by, and described in, the Commission's Guidelines. However, under the Guidelines (at page 8) Commission Staff is precluded from, "endorsing a particular position". TGI therefore questions whether the letter provided by Commission Staff is consistent with the Guidelines.

TGI respectfully submits that the requirement for the Commission Staff not to take positions on issues makes good sense. Commission Staff is not a party to the resulting Agreement; rather, the Negotiated Settlement Agreement is simply an agreement among intervenors and the applicant that a certain outcome is acceptable to them and should be jointly submitted for consideration by the Panel. In this case, the Agreement is clear that the Parties, having fully considered the information provided by Staff during the course of the NSP, have reached a compromise agreement that they consider to be in all respects fair, just and reasonable. As is inherent in every compromise, there will be outcomes about which a particular party was only supportive in exchange for other concessions. By commenting on the Agreement reached, Commission Staff places the parties in the position of having to justify individual items without being able to detail the steps that led to the outcome (which would not be appropriate in any event). It similarly places focus on isolated issues in the absence of the whole context of the negotiation that occurred in confidence. As a means of highlighting the difficulty this type of commentary creates, it is not possible for TGI to address in this letter Staff's statements about the information on NGV provided by TGI with reference to any additional information provided in the course of the confidential discussions.

To the extent that Staff has decided to make its views known on the present Agreement, TGI appreciates Staff having done so in a transparent manner; the alternative of having these views being conveyed in a non-transparent manner without any ability to respond would have been unpalatable. TGI nevertheless respectfully submits that the overall Settlement Agreement package should be assessed without isolating for consideration three issues where Staff might potentially have preferred a different outcome.

With that comment, Terasen Gas would like to express sincere thanks to Commission Staff and Intervenor representatives for their active participation in achieving this Negotiated Settlement Agreement on the Application. Terasen Gas also wishes to thank the NSP facilitator, Mr. Paul Cassidy, for his leadership, guidance and assistance to all parties throughout the NSP process.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Tom A. Loski

cc (e-mail only): Parties to the NSP