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August 15, 2008

B.C. Sustainable Energy Association and
Sierra Club of Canada (British Columbia Chapter)
1958 Parkside Lane
North Vancouver, BC
V7G 1X5

Attention: Mr. William J. Andrews, Barrister & Solicitor

Dear Mr. Andrews:

Re: Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively the "Companies" or the "Terasen Utilities")
Energy Efficiency and Conservation Programs Application - Project No. 3698512

Response to the B.C. Sustainable Energy Association and Sierra Club of Canada (British Columbia Chapter) ("BCSEA SCBC") Information Request ("IR") No. 1

On May 28, 2008, the Companies filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order No. G-102-08 setting out the Preliminary Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to BCSEA SCBC IR No. 1.

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

Yours very truly,

On behalf of the TERASEN UTILITIES

Original signed

Tom A. Loski

Attachment

cc: Erica M. Hamilton, Commission Secretary, BCUC
Registered Parties (e-mail only)

1.0 Reference: Exhibit B-2, Companies' response to BCUC Staff IR1.3.1

Terasen provides extensive information concerning the difficulties of estimating the effects of free-ridership and spillover from utility energy-efficiency programs and the high costs of the evaluation studies required to estimate them.

1.1 Has Terasen considered the possibility of adopting stipulated or "deemed" net-to-gross ratios, based on less costly means of estimation such as secondary research into prior evaluation studies for specific program types and periodically targeted market research? If so, please explain why Terasen does not favor such an approach over ignoring "naturally occurring" or market-driven efficiency improvements. If not, please explain why not.

Response:

The Terasen Utilities have not considered the possibility of adopting deemed net to gross ratios. These would also be notional and would also diminish the value of the DSM cost-benefit tests. The Companies' view is that the deeming of the net-to-gross ratios would be as contentious as determining free rider rates through other methods. Further, the Companies are unclear on which body would be appropriate or have authority to deem net-to-gross ratios. The inclusion of free riders makes little difference in the TRC of the overall portfolio (i.e. the net change in the TRC ratio is only 0.2% and TRC remains above 1.0 even if free rider effects are included), as noted on page 6 of the Companies' response to BCUC IR 1.3.1. And finally, the Companies are not suggesting that they receive a financial incentive based upon TRC, but rather be given approval to capitalize by way of a regulatory asset deferral account all EEC expenditures. Under the proposed financial treatment, the Companies' return is not affected by free rider effects, as the Companies are not proposing an incentive tied to TRC. The Companies feel that removing the need for significant resources spent on discussion about the slight variances in the TRC that result from finessing free rider results will reduce the administrative burden to the Companies, the Commission, and Stakeholders, thus maximizing value for ratepayers.

1.2 Does Terasen agree with the proposition that some method for accounting for program effects above and beyond what would have transpired in the marketplace is necessary for program design and resource planning? In particular, how else would Terasen determine how much of projected program savings to subtract from future gas delivery requirements for supply planning without netting out the amount of efficiency improvements already implicit or explicit in its future sales forecasts?

Response:

The Terasen Utilities would not agree that some method for accounting for program effects above and beyond what would have transpired in the marketplace is necessary for program design and resource planning.

The problem with estimating program effects above and beyond what would have transpired in the marketplace is that the demand forecast is based upon an analysis of historical data, with known demand drivers such as retrofit activity, changing housing mix, etc. being factored in. Historical data reflects (among other things) the savings which were a result of past DSM programs, and therefore when trending this data going forward, the forecast would already factor in future DSM savings. It would only be the incremental savings achieved by additional DSM programs that are not factored in, but that would only be the case over the short-term until the savings are realized and then become an input to the next forecast.

From a resource planning perspective, the size of the volumes in question are very small in comparison to TGI total annual residential and commercial demand. For example, over the three-year period of the currently proposed DSM programs, the average annual savings represents 0.46% of the total forecast TGI residential and commercial annual demand. Therefore this would have little impact to resource planning.

From a program design perspective, there is also a minimal impact seen when including or excluding free riders. As discussed in the Terasen Utilities' response to BCUC IR 1.3.1, the impact to the TRC ratio when including and excluding free riders is a net change of only 0.2 and TRC remains above the threshold. So long as the TRC ratio remains above the threshold level, no impact would be realized.

2.0 Reference: Exhibit B-1, Application, p. E-2a

Terasen states that natural gas prices have more than doubled since 1998.

2.1 Please provide the beginning and ending values underlying the calculation supporting this statement, stating whether they are in nominal or constant dollars indexed to a specific year.

Response:

Please see Appendix 3 to Exhibit B-1 as well as BCUC IR 1.57.2. These are in nominal dollars i.e. not adjusted for inflation.

3.0 Reference: Exhibit B-1, Application, pp. 47-8, re program principles, program integration

3.1 To what extent should integration of Terasen's gas energy-efficiency programs with BC Hydro's efforts targeting the same customers be a key gas efficiency program principle?

Response:

The Companies' view is that coordination of utility offerings is important, as outlined in section 7.3.2. of Exhibit B-1. The Companies also believe that it is the role of the British Columbia Partnership for Energy Conservation and Efficiency (BCPECE) to coordinate conservation activity in British Columbia, as outlined in the response to BCUC IR 1.19.1. Since BC Hydro and the Terasen Utilities have different owners and ownership structures, and therefore different business prerogatives and therefore key messages to customers, the Companies are of the view that coordination between utilities rather than integration of the Terasen Utilities energy efficiency activity into BC Hydro's energy efficiency activity is the appropriate approach to joint programs.

3.2 Does Terasen agree that in some markets such as new construction, close integration or even joint delivery has the potential to reduce program implementation costs, deepen per-participant savings, and increase market penetration?

Response:

Yes, the Terasen Utilities would agree that joint delivery has the potential to reduce program implementation costs and deepen per-participant savings. As noted above, the Companies favor coordination over integration as an approach. Should the Companies receive funding approval for new construction programs, the Companies would commence discussions with key stakeholder groups such as the Canadian Homebuilders' Association of BC, the Greater Vancouver Homebuilders' Association and the Urban Development Institute as to the best way for their respective members to receive conservation programming.

4.0 Reference: Exhibit B-1, Application, pp. 47-8, re program principles, Principle 3

Principle 3 states: "EEC expenditures will be efficient, with non-incentive costs not exceeding 50% of the expenditure in a given year."

4.1 Please explain the justification for this measure of expenditure efficiency.

Response:

The Companies in their best judgement felt that this is a reasonable approach to the breakdown of incentive vs. non-incentive costs, based on the Companies' previous experience. Please see Exhibit B-1, Table 1, Page E-5: the DSM expenditures currently approved for the Companies are approximately 50% incentive vs. 50% non-incentive costs.

5.0 Reference: Exhibit B-1, Application, pp. 47-8, re program principles, Principle 5

Principle 5 states: "The Total Resource Cost/Benefit of the Portfolio over the funding period will have a ratio of 1 or higher."

5.1 Does Terasen agree that this principle reflects a minimum performance objective for the EE program portfolio? If not, please explain why not.

Response:

The Companies' view is that an overall portfolio TRC of 1.0 or higher is the minimum acceptable threshold for a cost-effective EEC portfolio of activity.

5.2 Does Terasen agree that *maximizing* net resource benefits (as measured under the TRC test as the difference between present worth benefits and costs), is also an appropriate economic objective, subject to a budget constraint, for an EE program portfolio?

Response:

The Companies do agree that maximizing net resource benefits as measured by the TRC, within available budgets, is a worthwhile goal for an EEC program portfolio, however the Companies' view is that there are other principles that must be weighed as well. For example, in Section 5 of Exhibit B-1, the Application, the first Principle outlined by the Companies is one of universality, namely that programs should be available for all residential and commercial customers. As can be seen in Table 6.13 on page 85 of Exhibit B-1, the Commercial Energy Efficiency program area has a higher TRC at 3.7 than the Residential Energy Efficiency program area at a TRC of 2.4. If one were to run an EEC portfolio with the sole goal of maximizing TRC benefits, presumably one would only run Commercial Energy Efficiency programs, which runs counter to the first Principle as outlined by the Company. Similarly, the Companies are proposing to undertake some activities such as the Conservation Education and Outreach campaign that have a cost associated with them, but no quantifiable benefits at this time that would contribute to maximizing TRC, as the Companies believe that creating a conservation mindset in British Columbia is crucial to the success of individual programs and to supporting the energy conservation and greenhouse gas reduction goals established by the Government of British Columbia. Since the Conservation Education and Outreach expenditure could be considered detrimental to TRC as it has costs but no benefits attributed to it, a portfolio that had a sole goal of maximizing TRC would not undertake this very important activity. It should be noted that the portfolio of EEC activity as proposed has a TRC ratio of greater than 1.0, and thus provides benefits that are greater in value than the costs associated with obtaining those benefits.

6.0 Reference: Exhibit B-1, Application, pp. 58-59, re new residential construction program

6.1 Please explain why Terasen's program evidently does not consider improved building shell efficiency improvement beyond baseline levels, such as high-performance windows, reduced air infiltration measures, and added insulation (in contrast to the commercial new construction program).

Response:

Building shell measures were considered in the CPR and in the "Terasen Gas CPR Measures Update". As can be seen in Exhibit 2.6 (p4) of the Measure Update report, the measures were generally not cost effective. The only measures that passed were air sealing (lower mainland and interior only), windows, and the EGNH 80 program. Air sealing was thought to be too small to build a program around. Windows and EGNH 80 are currently being addressed by programs in the marketplace.

6.2 Please explain why Terasen's program evidently does not address gas and non-gas resource efficiency upgrades comprehensively, i.e., integrating electricity and water efficiency upgrades with gas efficiency improvement, particularly thermal load reductions that reduce both heating and cooling energy requirements?

Please include in the response any supporting analysis or studies conducted to support either or both decisions.

Response:

The portfolio of activity put forward in the Terasen Utilities EEC Application is based on natural gas measures as it is proposed that the activity be funded through the Terasen Utilities' customers' rates. That is, the Terasen Utilities customers can only be expected to pay for natural gas measures; as noted in the response to IR 3.1 above, the Companies are supportive of pursuing a coordinated approach to EEC programming.

The CPR, measure rescreening and the EEC programs do consider the benefits to both electricity and natural gas when screening alternatives. As noted in 6.1 above, thermal upgrades were evaluated, but typically did not pass the benefit / cost test for the measures.

7.0 Reference: Exhibit B-1, Application, pp. 77-8, industrial customer efficiency program

Terasen states:

"The Companies' industrial customers generally make energy efficiency decisions based largely on the economic payback. As such, it may be difficult for the Companies to provide the level of EEC financial support that would make an energy efficient decision economic to an industrial customer."

7.1 Please provide the results of any research, analysis or study supporting Terasen's contention quoted above.

Response:

The statement made in the application is a result of conversations and discussions that the Terasen Utilities' (account managers and staff) has had with its industrial customers, along with its own knowledge of customer rates, customer volumes, and total number of customers. The Companies do not have a study or separate analysis to support this statement.

7.2 Has Terasen considered the possibility of a custom program for industrial customers providing financial incentives to "buy down" the payback period of efficiency measures identified and characterized through specialized energy analyses to a level consistent with industrial customer financial requirements?

Response:

As noted in the Application, and pending the Commission decision, the Terasen Utilities have proposed to convene an industrial working group to evaluate and determine the needs of this group such that future incentives and programs could be developed. Due to the diverse nature of the industrial group of customers and their specific energy process requirements it is unlikely to be well served by blanket programs other than an energy audit program. Further, with exception of the recent workshop, this group of customers has not historically requested energy efficient programs. As a result, the Terasen Utilities did not have the information necessary to develop programs at this time and as such the Companies felt it would premature to request funds in this Application. As such there has not been any formal discussions or programs (incentive or otherwise) developed for this group of customers.

However, similar to both residential and commercial customers, the effect of a financial incentive to industrial customers is to either overcome the initial capital cost hurdle and/or to "buy down", or shorten, the Return on Investment (ROI) for the energy efficiency upgrade. However, a challenge in creating financial incentives with industrial customers is that the incentives to reduce the ROI to an acceptable level (typically approximately 2 years or less) may have to be substantial. From a rate perspective, due to the limited number of customers in certain rate classes the level of incentives may result in an unacceptable rate increase to industrial customers. Further, due to the limited number of industrial customers in some rates classes, and the potential impact on rates, some industrial customers may not feel it is appropriate that their rate is partly paying for their direct competitor to receive incentives for capital which may make that company more competitive. Prior to implementing financial incentives for this group of customers, these hurdles will have to be overcome.

7.3 If so, why does Terasen conclude that such a program would not be feasible and worthwhile to budget and plan for during the three-year program period covered by the Application? If not, why did Terasen decline to propose such a program in the Application?

Response:

Please refer to the response to BCSEA SCBC IR 1.7.2 above.

8.0 Reference: Exhibit B-1, Application, p. 82, portfolio cost-effectiveness

8.1 Please provide the avoided marginal commodity, transportation, storage, and other supply and distribution costs underlying Terasen's valuation of gas efficiency program savings. Please provide this information on an annual basis as far into the future as Terasen's economic analysis extends, in as much detail as possible (e.g., seasonally), in electronic spreadsheet format (e.g., MS Excel).

Response:

Please see the response to BCUC IR 1.13.1. The information in this response is the greatest degree of detail available.

9.0 Reference: Exhibit B-1, Application, p. E-6, Table 2 re portfolio budget breakdown

9.1 On what basis did Terasen conclude that spending 24% of the three-year portfolio budget on conservation education and outreach ($13.8 million out of $56.6 million) would be cost-effective?

Response:

It is the view of the Companies that supporting the creation of a conservation culture in British Columbia is crucial to the success of the EEC portfolio, and to achieving the larger energy conservation and greenhouse gas emission goals of the government of British Columbia. The Companies' position is that a customer that has been "pre-conditioned" with general mass media messaging about the impacts of natural gas consumption is far more likely to respond to communications regarding a specific program and therefore is more likely to participate in that program. Further, the Companies' view is that the expenditures proposed for Conservation Education and Outreach for natural gas would have the effect of creating spillover in conservation outcomes in other areas, such as water and electricity.

For a discussion on the Companies proposed cost-effectiveness approach to the Conservation Education and Outreach expenditure, please refer to Exhibit B-1, the Application, Section 6.13, page 83. The proposed approach is further explored in the response to BCUC IR 1.47.1. The Companies have not attributed any savings to this expenditure and would develop the methodology and an understanding of impacts and behaviour changes resulting from the proposed expenditure through the ad tracking approach outlined in the response to BCUC IR 1.47.1, with a view to attributing energy savings resulting from Conservation Education and Outreach to the expenditure in the next Application for EEC funding, scheduled at this time for 2010. It should be noted that the overall TRC ratio of the Portfolio of EEC activity proposed is 2.9 with free riders and 3.1 without free riders, well above the proposed Portfolio level TRC ratio of 1.0, and that the Portfolio level analysis results cited above include the <u>expenditures</u> for Conservation Education and Outreach program area, but does not include any accounting for energy savings <u>benefits</u> from this program area.

9.2 Please provide any research, analysis, or studies conducted to assess the probable outcomes of the education and outreach effort, especially in gas energy savings resulting directly from these efforts?

Response:

Please see the response to BCSEA SCBC IR 1.9.1 above.

9.3 Did Terasen examine the share of gas efficiency portfolio budgets devoted to education and outreach by other gas utilities, or other non-gas efficiency program administrators, and compare these values with its own proposal? If so, please provide the results of any such research. If not, please explain why not.

Response:

Please see the response to BCUC IR 1.16.7.

10.0 Reference: general. Fiscal year cf. Calendar year

Information regarding the Companies' finances is presented by year (e.g., 2008, 2009). The Marbek Conservation Potential Review at Appendix 1 refers to, e.g., FY 2003/2004.

10.1 Are Terasen's financial figures presented by calendar year? If not, please explain.

Response:

The Terasen Utilities financial figures are presented by calendar year.

11.0 Reference: Exhibit B-1, Application, 3.6 Government Policy, pp.39-42,

In the following IRs, statutory references are to the Utilities Commission Act, as amended.

11.1 Please confirm that the application includes an “expenditure schedule” filed pursuant to s.44.2(1)(a).

Response:

Confirmed. The Application identifies the EEC, or demand-side, expenditures for which Commission approval is sought.

11.2 Please confirm that the Companies understand this proceeding to be what is referred to in s.44.2(3) as the Commission “reviewing an expenditure schedule submitted under subsection (1)”.

Response:

Confirmed.

11.3 Please confirm that the Companies understand that pursuant to s.44.2(3) the Commission, after reviewing the expenditure schedule, must either (a) accept the schedule if the Commission considers that making the expenditures referred to in the schedule would be in the public interest, or (b) reject the schedule.

Response:

Not confirmed. Subsection (4) also provides that the Commission can accept or reject part of a schedule.

11.4 Please confirm that the Companies understand that in considering whether to accept or reject the expenditure schedule the Commission must consider the factors itemized in s.44.2(5).

Response:

Confirmed.

11.5 Paragraph 44.2(5)(b) requires the Commission to consider "the most recent long-term resource plan filed by the public utility under section 44.1, if any" [underline added]. Is there such a plan? Please confirm that s.44.2(6) is not applicable.

Response:

Confirmed. TGI, TGVI and TG (Whistler) Inc. jointly filed their resource plan on June 27, 2008 (the "TGI-TGVI-TGW 2008 Resource Plan"), pursuant to section 44.1, and is available for download on the Terasen Gas web site www.terasengas.com.

11.6 Paragraph 44.2(5)(c) requires the Commission to consider whether the schedule is consistent with the requirements under section 64.01 and 64.02, if applicable". Please confirm that s.64.01 relates to BC Hydro and is not applicable. Please confirm that s.64.02 is not applicable, or explain how it is applicable.

Response:

Section 64.01 applies only to BC Hydro. Section 64.02 applies only to BC Hydro and "a prescribed public utility", meaning a public utility that has been prescribed by regulation. The Terasen Utilities are not "a prescribed public utility".

11.7 Paragraph 44(5)(d) requires consideration of whether DSM expenditures are "cost-effective with the meaning prescribed by regulation, if any". [underline added] Please confirm that there is no such regulation, or otherwise explain.

Response:

Confirmed.

12.0 Reference: Exhibit B-1, 6.4 Residential Fuel-Switching Program Area; Exhibit B-2, BCUC IR 2.4

The Companies say that the residential fuel switching activity for the retrofit market is focused on Vancouver Island and would be based on encouraging residents to switch from oil to gas heating. (p.63)

12.1 Please confirm that the proposed retrofit fuel-switching programs would apply only on Vancouver Island.

Response:

Please see table 6.4 on page 63 of Exhibit B-1, the Application, for an outlined of proposed measures and geographic locations for fuel-switching activity.

12.2 To what extent is TGVI competing with BC Hydro (e.g., natural gas versus electricity) for heating retrofits from oil or propane on Vancouver Island? Please discuss whether this changes the appropriate comparison to a comparison between natural gas and electricity instead of a comparison between natural gas and oil.

Response:

Currently at TGVI, residential natural gas rates are set at the prevailing BC Hydro electric rate (on an efficiency adjusted basis). As such, electricity is a competitive alternative for heating retrofits from fuel oil or propane for consumers in the TGVI service territory. However, the Companies maintain that it is appropriate to make the comparison between natural gas and fuel oil as it is the opinion of the Terasen Utilities that natural gas is a more efficient energy source for home heating applications than electricity (please refer to the response to BCSEA IR 1.17.1).

12.3 In what way does the "current regulatory regime for TGVI … not allow Terasen to offer customers who switch to natural gas an incentive to install Energy Star equipment"? (p.65) What is the rationale?

Response:

Please refer to the response to BCUC IR 1.27.1.

13.0 Reference: Exhibit B-1, Application, 7.2.1 Revenue Requirements and Rate Impacts

The Application discusses in some detail the revenue requirement and rate impacts of the additional costs of implementing the EEC proposal; however it does not appear to address the possibility that a successful plan of energy efficiency and conservation could have the effect of reducing or delaying the need for supply-side capital and operating costs.

13.1 Does the current EEC proposal have the effect of reducing or delaying the need for supply-side capital and operating costs?

Response:

Yes, the EEC proposal will have the effect of reducing supply side costs over the long term. While it is difficult to attribute deferral of a particular capital project to the addition of a single customer in any given year, clearly the cumulative affects of DSM programs create efficiencies throughout the natural gas energy system that benefit all existing and future customers. See also the Companies' response to BCUC IR 2.21.1.

The impact of the Companies' EEC Application on reducing or delaying the need for supply-side capital costs and supply-side operating costs on its own transmission system is discussed in Chapters 3, 4 and 5 of the 2008 Terasen Gas Resource Plan, submitted to the Commission on June 27th and available for download on the Terasen Gas web site www.terasengas.com. The impact that EEC programs could have on these costs are limited to those costs related to system expansion requirements that result from core demand growth. System expansion requirements are for the most part determined by the need to meet core peak demand or the amount of gas used during the coldest days expected. While energy efficiency programs typically help to reduce annual demand, their impact on peak demand is typically smaller in scale since even the most efficient natural gas heating equipment is working hardest during these cold events. The Terasen Utilities have found that the impact of EEC Programs in the Companies' current application on delaying capacity related transmission infrastructure typically ranges from zero to just a few years. More specifically, the Terasen Utilities' review of the impact of the programs included in the 2008 EEC Application on infrastructure expansion projects over the next 20 years is limited to the TGI Interior transmission system since constraints on the TGVI and TGI Coastal systems within this time period have been alleviated by constructing the Mt. Hayes storage facility.

A constraint in the Okanagan area of the TGI Interior transmission system requiring system expansion has been identified by 2016 under the reference case demand scenario. Effective EEC programming is among the factors that could lead to the demand level provided in the low demand forecast. If a low demand forecast were to come true, the Okanagan expansion requirement could be delayed to 2019, however, it is difficult to determine at this time how much of that delay and the related costs would be directly attributable to EEC program effectiveness.

13.2 Is it possible that a very successful energy efficiency and conservation program could have the effect of reducing the TG's or TGVI's revenue requirements? Please discuss.

Response:

Revenue requirements (deficiency) for a particular year depends on many factors driven by impacts on revenue sources and cost inputs as follows:

1. Delivery margin: This includes the impact of demand (use per customer), customer additions, deferral accounts and tariff rates.

2. Cost of Service (excluding cost of gas): This includes O&M expenses, property tax, depreciation, amortization, income tax, interest expenses and return on equity.

Successful energy efficiency and conservation program would likely contribute to reducing overall demand (use per customer) except in those instances where gas is the substituted energy of choice (displacing electricity or heating oil for instance). This is just one of several factors that impacts revenue requirement. Reduced throughput will have a modest favourable impact on some directly variable costs such as compressor and line heater fuel which could reduce revenue requirements. Therefore, the effect of successful energy efficiency and conservation program cannot be viewed in isolation.

13.3 If the answer to the previous question is yes, would this create a conflict of interest for TG and TGVI between their interest in making a return for their investors and their interest in providing their customers with beneficial opportunities to reduce their demand and their gas bills? Please discuss.

Response:

The Companies do not consider there to be any conflict of interest posed by the situation described in the question. It is the Companies' view that the financial treatment proposed (namely capitalizing and amortizing EEC expenditures) removes a disincentive to undertake EEC programs by rendering the Companies indifferent as to whether monies are invested in system expansion or customer demand reduction. In the absence of capital treatment of EEC expenditures, the Companies would be more incented to invest in supply-side resources than demand-side resources because the return to the investor on supply-side resources (assuming a fair return) would be greater; this would put the investor owned utility in a difficult position between protecting investor interests and helping customers to reduce their energy bills.

14.0 Reference: Exhibit B-1, Application, 3.2.1 Terasen Gas Inc. EEC Initiatives

14.1 Please define and describe the “DSM Achievement Incentive.”

Response:

Please refer to the appropriate sections in Order No. G-85-97 provided in Attachment 14.1, as well as the response to BCUC IR 1.8.1.

15.0 Reference: none

BC Hydro uses the avoided cost of new supply as its benchmark for deciding if conservation measures are 'economic'.

15.1 What does Terasen use as its benchmark for whether conservation measures are economic? The market price of natural gas? The avoided cost of new infrastructure?

Response:

The Companies are proposing that the overall EEC Portfolio have a TRC of 1.0 or greater. The avoided cost of gas used in the analysis presented herein, which has a portfolio level TRC of 2.9 including free riders and 3.1 excluding free riders, is outlined in the response to BCUC IR 1.13.1.

16.0 Reference: Exhibit B-1, Application, Appendices 1 and 9

16.1 What portion of the achievable energy savings identified in the Conservation Potential Review (Appendix 1) and the Habart and Associates report (Appendix 9) does the current EEC proposal aim to capture?

Response:

When comparing the projected uptake rates from programs with the CPR, it should be remembered that the CPR methodology assumes that all the opportunities are captured in each year while programs require time to launch and ramp up participation. The following response compares the projected results from the three year EEC program with 5 year forecast from the CPR. Hence the program targets will be lower than the forecast due to the differences in time periods and the ramp up of program savings.

The EEC addresses about 23% of the CPR “Most Likely” potential for 2010/11. However the EEC does not address all the end uses outlined in the CPR as it was not possible to develop cost effective initiatives for all the areas noted in the CPR.

Comparing the end uses addressed in the EEC, with the CPR results for those same end uses, the share of the CPR addressed by the EEC increases to about 31%.

On a sector basis, the Residential EEC plan addresses 8% of the identified potential while the commercial sector addresses 69%. Looking at just the end uses addressed, the Residential sector addresses 10% while the commercial sector addresses 95%.

There are a number of reasons for the differences in the EEC targets for Residential and Commercial.

- The CPR treats MURBs as part of the residential sector while the EEC treats them as part of the Commercial sector. This understates the residential EEC impact and overstates the commercial impact.
- In the residential sector EEC program, targeted savings are lower than the CPR estimates.
  - o Furnaces target 81K GJ of savings vs 949K GJ in the CPR. The difference is due to legislation which is in place for New Construction and is expected by 2010 for the Retrofit segment. While the EEC does not take credit for the savings from regulation, past furnace programs were instrumental in building support for the legislation.
  - o E* Appliance EEC program only targets the top 15 – 20% of E* sales due to the high number of free riders as E* has a high market share. The program targets 61K GJ vs 1,254 GJ in the CPR.
  - o The Fireplace program targets 98K GJ vs 137k GJ in the CPR.

In the residential sector, the following end uses from the CPR are not addressed.

- Efficient DHW Equipment.
  - o This opportunity was based largely around an integrated space and water

heating concept that has not reached commercialization.

- DHW Load Reduction
    - This opportunity was based around efficient shower heads, faucets and pipe insulation, and would have a high free rider rate that would likely make a program not cost effective.
- DHW Heat Recovery and Heat Traps
    - Heat traps on DWH tanks are only cost effective if a plumber is in the house, while heat recovery applies to MURBs and is included in the Commercial programs.
- Efficient Windows
    - Programs supporting windows are already available in the marketplace
- Air Sealing
    - Only cost effective in the Lower Mainland and on Vancouver Island.
- Integrated Design (MURBs)
    - Included in Commercial
- Building Operation (MURBs)
    - Included in Commercial

In the commercial sector, the following end uses from the CPR are not addressed.

- EE Food Preparation (new and retrofit)
    - Slated for future development
- Hot Water Reduction for Food Preparation
    - Pilot project (Sarah – is this correct)
- Small Commercial EE Initiative
    - Not specifically targeted, but embedded with other commercial initiatives.
- Recreational and Other.
    - Not specifically targeted, but embedded with other commercial initiatives.

17.0 Reference: Exhibit B-1, Application, 6.4. Residential Fuel-Switching Program Area ($3.7 million), pp. 63-65; 7.2 Greenhouse Gas Emission Reductions, pp. 98-100

The Application asserts that displacing electricity with efficiently used natural gas will reduce greenhouse gas (GHG) emissions. Footnote 29 on page 63 appears to offer the only justification for this claim.

17.1 Please provide a detailed analysis of the basis for claiming that “the use of natural gas ... in place of electricity results in lower GHG emissions overall in the region” (Application, p. 63). Please address in this analysis the basis for assigning a GHG factor to electricity that would be displaced; and please address current government policy affecting GHGs in B.C.’s electricity sector, particularly Policy Actions 10, 18, 19 and 20 of the 2007 Energy Plan.

Response:

As stated in BCUC IR 1.62.1 and supported by the Northwest Power and Conservation Council[1], the marginal source of electricity generation for the Pacific Northwest is made up of primarily natural gas and coal fired generation. Appendix H of BC Hydro’s 2008 LTAP provides additional evidence of the marginal source of electricity generation in the region being thermal-based and its implications for GHG reductions as follows:

> “…the WCI is reviewing studies done by the California Energy Commission (CEC) that show amounts of GHG reductions in each Western state under different penetrations of energy efficiency and renewables.
>
> The CEC studies discussed in the above paragraph were performed by running hourly simulations of the WECC power grid with hourly loads across WECC being served by economic dispatch of generation available in the region. …the CEC studies demonstrate the reality that much load in WECC is served by natural gas fired generation. As the CEC increased penetration of renewables in the future in its alternative views of the future, the renewables will run to meet the load, thereby displacing natural gas fired generation that would otherwise be needed to meet loads. The CEC ran a few sensitivities with high GHG taxes in place. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal fired generation… …because coal generation emits about twice the amount of GHG/kWh than does natural gas fired generation. The CEC concludes that a good way to reduce GHG is to

[1] Northwest Power and Conservation Council, June 2008. Marginal Carbon Dioxide Production Rates of the Northwest Power System. 23p.

> reduce thermal generation levels by causing higher penetration of energy efficiency and renewable power supplies."[2]

Once BC Hydro reaches a position of self-sufficiency, they will be in a position to be a net exporter of electricity in all but a critical water year, since that criteria is used by the Province to define the self-sufficiency limit. Since BC Hydro trades electricity within the WECC, and will continue trading in accordance with the 2007 BC Energy Plan, replacing the use of electricity where practical with fuel switching energy efficiency programs will displace natural gas and coal fired generation as described in the quote above, both before and beyond 2016. The assigning of a GHG factor for the electricity that would be displaced and further supporting analysis is discussed below.

According to BC Hydro's 2005 Resource Options report the Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh) for a 560 MW Super Pulverized Coal Combustion Plant and 250 MW Combined Cycle Gas Turbine Plant are 855 and 350 tonnes per GWh respectively. In BC Hydro's 2007 Conservation Potential Review Summary Report a GHG factor of 550 tonnes per GWh was assigned for BC Hydro's electricity imports in F2006[3]. A modern combined cycle gas fired generator operates at 50 to 55% efficiency; whereas modern direct gas fired appliances operate at much higher efficiencies. For example, new high efficiency natural gas fired furnaces operate at 95% efficiency or higher. The Greenhouse Gas Emission Factor for a high efficiency furnace is 180 tonnes CO2 equivalent/GWh[4]. Therefore, there is a clear GHG reduction advantage to using natural gas in direct use applications to reduce the quantity of electricity produced by gas or coal fired generation and therefore reduces GHG emissions in the region.

Terasen Gas provided a detailed analysis on this issue in the 2007 BC Hydro Rate Design proceeding. We have included an excerpt of this evidence as Attachment 17.1. A discussion of the regional GHG impact analysis can be found in Section 5.1, pages 5 to 7 of this attachment. In the Commission's October 26, 2007 Decisions in the Matter of BC Hydro's 2007 Rate Design – Phase 1, the Commission agreed with Terasen's assertion that the direct use of natural gas for space and water heating in BC will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest.

> "Commission Panel commends Terasen for its initiative in leading evidence both concerning the use of electricity for space and water heating in BC Hydro's service area, and concerning the potential growth in demand for electric space and water heat that BC Hydro is forecasting. The implications of the growth in demand were among the reasons that led the Commission Panel to encourage and guide BC Hydro to

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[2] Global Energy, 2008. Renewable Energy Credit – Market Analysis of Potential Renewable Energy Sale in WECC. Prepared for BC Hydro and Appearing as Appendix H to BC Hydro's 2008 LTAP. P 10-11 of 47.
[3] BC Hydro, 2007 Conservation Potential Review, Summary Report, Date Nov. 20 2007. p. 12.
[4] 3600 (GJ per GWh) x 48.5 (kg CO2e per GJ) / 97% (assumed furnace efficiency)

> implement an inclining block residential rate, so that customers receive the correct pricing signal in this regard. **The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest**[5]" (emphasis added).

A recent American Gas Foundation, *Direct Use of Natural Gas: Implications for Power Generation, Energy Efficiency and Carbon Emissions* supports the argument that the direct use of natural gas lowers total energy consumption and carbon emissions[6]. The study found that:

- The direct natural gas in residential and commercial applications can increase the productivity of available energy supplies, reduce the cost of energy and reduce CO2 emissions.
- In all direct use scenarios considered by the study CO2 emissions are reduced.
- The direct use of natural gas would result in significant avoidance of electricity generation capacity.

Utilities in other jurisdictions have also identified British Columbia's resources as an opportunity to help them meet renewable requirements and greenhouse gas emission targets. For example, in June 2008, Pacific Gas and Electric Company ("PG&E") in California completed Phase 1 of a BC Renewable Study which identified a "…vast amount of renewable resources in BC, …strong feasibility of building a transmission line and good indicators of commercial viability…" for acquiring renewable resources from BC[7]. PG&E is proceeding with Phase 2 of the study. This study provides an example of a possible solution cross political boundaries to find the optimal solution in reducing GHG emission for the PNW region.

It is The Companies' view the achievement of energy self sufficiency and net zero emissions from thermal generation in BC does not alter the regional GHG benefits of the direct use of natural gas for space and water heating in BC. When BC achieves energy self sufficiency the region would benefit from British Columbia exporting its clean power and displacing the use of coal and natural gas fired generation. The direct use of natural gas in British Columbia for space and water heating will reduce the amount of new generation required in BC to make self sufficiency possible and/or make available larger quantities of clean electricity for export and help reduce overall GHG emissions.

[5] BCUC Decision in the Matter of British Columbia Hydro and Power Authority 2007 Rate Design Application – Phase 1, October 26, 2007, p. 191.
[6] American Gas Foundation, "Direct Use of Natural Gas: Implications for Power Generation, Energy Efficiency and Carbon Emissions, April 2008.
[7] Pacific Gas and Electric Company – BC Renewable Study Phase 1 report. June 2008.

17.2 Please clarify to what extent "ensuring that the Terasen Utilities' distribution infrastructure is used to its maximum efficiency" (Application p. 63) is relevant to the calculation of GHG emissions.

Response:

The statement "ensuring that the Terasen Utilities; distribution infrastructure is used to its maximum efficiency" is referring to the economic benefits customers receive through lower delivery rates as a result of higher utilization rates. It is not referring to GHG reductions.

17.3 Please comment on the extent to which "ensuring that the Terasen Utilities' distribution infrastructure is used to its maximum efficiency" (Application p. 63) would cause the Companies to increase their bulk transmission capacity, for example by expanding compression in the TGVI system or extra looping to address increased demand, and please comment on the effect of such changes on the calculation of GHG emissions.

Response:

The increase in gas load from the displacing of electricity with efficiently used natural gas will have minimal impact on TGI and TGVI requirements for expanded transmission capacity, and therefore minimal impact on GHG's emission increases that would result from such expansion. Also, increases in gas load from fuel switching programs would generally be offset by load reductions from other efficiency and conservation programs that are part of the Terasen Utilities' EEC application and it is the Companies' view that these programs should be considered collectively. Further, overall regional GHG emissions will be reduced by the proposed fuel switching programs (see response to IR 17.1 above). Additional information on the Terasen Utilities' transmission expansion requirements is provided in the TGI-TGVI-TGW 2008 Resource Plan.

18.0 Reference: Exhibit B-1, Application, 3.1 Energy Use in British Columbia, Figure 3.1, p. 17; 6.4. Residential Fuel-Switching Program Area ($3.7 million), text and Table 6.4, p. 63

The Application asserts, “fuel switching activity for the retrofit market is focused on Vancouver Island, and would be based on encouraging residents in the TGVI service area to get off oil ...”; however, Figure 3.1 indicates that heating oil provides only 0.6% of residential energy requirements in B.C. Table 6.4 lists several program measures, of which only ‘Furnace Fuel Substitution’ and ‘Fireplace Fuel Substitution’ might involve substitution of gas in the place of oil.

18.1 Please provide a version of Table 6.4, showing the numbers of customers that would be expected to participate in each program, and the type of fuel or energy source they would be expected to switch from.

Response:

Please see the tables below. As noted in the response to BC Hydro IR 1.1.1, in the case of the TGVI programs, the Companies are unable to predict which energy source participants would be switching from.

TGI Residential New Construction		
Measure Name	# of Participants	Alternate Fuel Source
NG Range	10,431	electricity
NG Dryer	3,634	electricity
TGVI Residential New Construction		
Measure Name	# of Participants	Alternate Fuel Source
NG Water Heating	1,339	electricity
NG Range	233	electricity
NG Dryer	464	electricity
TGVI Residential Retrofits		
Measure Name	# of Participants	Alternate Fuel Source
NG Range	1,170	propane, electricity
NG Dryer	1,170	propane, electricity
Energy Star Furnace/Boiler	1,593	propane, oil, wood, electricity
EnerChoice Gas Fireplace	722	propane, wood

18.2 Please discuss the low proportion of residential heating oil users in B.C. in relation to the $3.7 million expenditure proposed to address fuel switching for this group, clarifying why this rate of expenditure is justified for such an apparently small group.

Response:

It should be noted that the $3.7 million expenditure is intended to address not only oil to gas fuel switching for retrofits on TGVI, but as can be seen in the response to BC Hydro IR 1.1.1, other fuel switching activities related to new construction.

As discussed on pages 51 and 52 of Exhibit B-1, the Application, expenditure levels for Fuel Switching were developed "from the bottom up", that is, by estimating the incentive level needed to spur participation, participation levels and non-incentive costs. More information on the expenditures for each individual measure can be found in the attachments filed in response to BCUC IR 1.56.2.

The information below is taken from Natural Resources Canada's Survey of Household Energy Use for 2005.

Source: (http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_21_e_2.cfm?attr=0)

Heating System Type	**Number of units**
Heating Oil – Normal Efficiency	48,000
Heating Oil – High Efficiency	13,000

It shows that there are over 60,000 heating systems still using oil in British Columbia. It is the Companies' view that proposing to spend $681,000 out of the proposed $3.7 million for the Residential Fuel Switching program area to switch about 1,500 of those systems on Vancouver Island from oil to natural gas is not an unreasonable amount, and that this expenditure will reduce greenhouse gas emissions as natural gas has a much lower GHG profile than heating oil.

18.3 Please discuss whether the Companies' assessment of GHG emissions avoided through fuel switching would be affected by the assumption of whether electrical heating were provided by resistance heating or by heat pumps.

Response:

Please see the Companies' response to BC Hydro IR 1.1.1., CEC IR 1.3.1 and CEC IRs 1.16.1 and 1.16.2. The Companies have used the emissions factor associated with electricity as a proxy, given that the Companies cannot adequately assess the number of program participants in the TGVI residential retrofit Energy Star furnace/boiler program that would be fuel switching from each energy source. In general, any assessment of GHG emissions avoided through fuel switching to natural gas from electrical heat would be lowered if electrical heating were assumed to be provided by heat pumps rather than by electrical resistance heating, because heat pumps consume less electricity than resistance heating.

18.4 Please define the expression "optimal balance" on page 64 of the Application. Where, in the Companies' view, does this balance lie, quantitatively?

Response:

It is the Companies' position, as expressed in the responses to BCUC IRs 1.2.4 and 1.23.4, that British Columbia's valuable electricity resources are best used in end-use applications that reflect that value, such as keeping the lights on and powering computers and household appliances, while natural gas is best used for space and water heating, and for displacing electricity in some end uses such as cooking and clothes drying. The optimal balance of the energy system in the Province would be one where British Columbians are not squandering electricity on end uses that could be provided for by other more efficient energy sources, thus reducing our need to import electricity from other jurisdictions that generate it using inefficient coal and natural gas as inputs. Further, this would make more of British Columbia's clean electricity available to export to those jurisdictions to displace inefficient thermal generation, thus reducing GHG emissions in the region overall. (See also the response to BCSEA 1.17.1).

British Columbia has electricity rates that are among the lowest in North America. The electricity rates and rate structures, particularly for residential and smaller commercial accounts, have not to this point provided price signals to electricity consumers about the much higher costs of new electricity supply and have masked the true costs of inefficient use of the province's Heritage electricity resources. Natural gas, on the other hand, is subject to market-based commodity pricing so natural gas consumers experience price signals much more directly. BC Hydro's proposed Residential Inclining Block rate, if approved by the Commission, will be a significant step towards rectifying this imbalance. Similar rate structures anticipated for other electricity rate classes and additional rate structures enabled by the provincially-mandated Smart Meters will also improve this situation.

July 25, 2008 Revision. The following two Information Requests are added:

19.0 Reference: Exhibit B-1, Application, 6.6 Joint Initiatives Program Area ($3 million), pp. 66-68; 7.3.2 Policy Action #2, pp. 101-102

19.1 Please confirm whether the DSM for Affordable Housing, Support for Audits for a Provincial Home Retrofit Program and Building Labeling programs are programs that are being coordinated through the government's Policy Action #2.

Response:

The Terasen Utilities' involvement in DSM for Affordable Housing is being coordinated through the Working Group on DSM for Affordable Housing, discussed in BCUC IR 1.29.1, and in MEMPR IR 1.2.0. Support for Audits for a Provincial Home Retrofit Program is discussed in MEMPR IR 1.3.0. Building Labeling is a program that has been proposed by government and that work is being coordinated through the Public Sector Energy Conservation (PSECA) initiative. As described in the responses to BCUC IR 1.77.1, and BCUC IR 2.51.1, the Companies believe that BCPECE is an appropriate forum for the coordination of conservation activity in British Columbia.

19.2 Please discuss what other Terasen efficiency and conservation programs might be expedited through joint initiatives. Please provide an approximate indication of the magnitude of additional energy savings that might be achieved.

Response:

At this time, there have been no additional discussions about coordinated activity other than those described in the Application and in the responses to Information Requests, so the Companies are unable to speculate as to other natural gas EEC activities, that might be offered on a coordinated basis, and the energy savings that might arise. The changes in natural gas usage that result from the measures and areas of program activity for which funding is being requested in this Application are outlined within the Application.

19.3 Please discuss in more detail the objectives and timelines for the Joint Initiatives Program Area, including the extent to which the objectives could be effectively expanded if more money were allocated to this program area.

Response:

As noted in Exhibit B-1, Application, Section 6.6, "*The funding for this program area will be used to support the initiatives of partners, and as such, the initiatives outlined below are those that the Companies are aware of today.*" So the objective of the Joint

Initiatives program area is to support partner initiatives. Given that, as indicated, the Companies have outlined the initiatives that they are aware of today, the Companies cannot speculate as to the potential expansion of activity. In terms of timelines, the Companies would expect that the Companies' participation in the initiatives outlined in Sections 6.6.1, 6.6.2, 6.6.3 and 6.6.4 could commence three months after the Commission grants approval for the Joint Initiatives funding.

20.0 Reference: Application, 6.9.1 Innovative Technologies – Solar Thermal, p. 72

20.1 Please describe the Companies' proposal in regard to solar thermal energy in more detail, addressing why the Companies propose to limit their incentives to $500 and to limit the scope of their program to solar pre-piping.

Response:

Solar thermal is still a developing technology and the Companies believe there will be more CSA approved products on the market for customers to choose from in the near term. Due to solar thermal technology at this point being cost prohibitive and only one solar thermal system available in Canada that is CSA approved, the Companies believe it is appropriate to limit the incentive to solar pre-piping only. The Companies believe that as cost of solar thermal systems become cheaper, buyers of homes from builders who have installed solar pre-piping will be able to take advantage of future incentives offered by local, provincial and federal governments.

Attachment 14.1

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-85-97

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

and

An Application by BC Gas Utility Ltd.
for Approval of a Performance Based Rate Plan to
Determine Revenue Requirements for the Years 1998 - 2002

BEFORE: L.R. Barr, Deputy Chair)
and Acting Chair) July 23, 1997
K.L. Hall, Commissioner)
P.G. Bradley, Commissioner)

O R D E R

WHEREAS:

A. On February 5, 1997 BC Gas Utility Ltd. ("BC Gas") filed with the Commission its Performance Based Rate Plan and Revenue Requirements Application 1998 - 2002 (the "Application") for approval to set rates for the years ending December 31, 1998 through 2002; and

B. The Commission reviewed the Application and issued Order No. G-13-97 setting down a Pre-Hearing Conference to commence on February 28, 1997. Following the Pre-Hearing Conference, the Commission issued Order No. G-24-97, which included a Regulatory Agenda and Timetable, setting a second Pre-Hearing Conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. On April 24, 1997 the Commission, by Order No. G-47-97, amended the dates set out in the Regulatory Timetable and revised the public hearing date to June 23, 1997; and

C. Commission Order No. G-68-97 cancelled the public hearing scheduled for June 23, 1997 and allowed for a rescheduling by way of a future Commission Order; and

D. The Alternative Dispute Resolution ("ADR") process commenced on June 2, 1997 and, on June 26, 1997, BC Gas, ADR participants and Commission staff agreed to a proposed settlement agreement; and

E. On July 10, 1997 the proposed settlement agreement was circulated to all Registered Intervenors and the Commission Panel. No comments were received; and

F. The Commission has reviewed the proposed settlement agreement and sets out its views in the Reasons for Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The Commission accepts the terms of the proposed settlement agreement as revised by its Consolidated Settlement Document and issues its Reasons for Decision.

2. BC Gas will comply with all the terms contained in the Consolidated Settlement Document accompanying the Reasons for Decision.

3. BC Gas is to inform all customers of the effect on rates of this Decision.

4. The public hearing into the application is not required and is therefore cancelled.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of July, 1997.

BY ORDER

Original signed by:

Lorna R. Barr
Deputy Chair and
Acting Chair

Attachment

IN THE MATTER OF

BC Gas Utility Ltd.

REVENUE REQUIREMENTS APPLICATION 1998 - 2002

Reasons for Decision

July 23, 1997

BEFORE:

Lorna R. Barr, Deputy Chair
and Acting Chair
Ken L. Hall, Commissioner
Paul G. Bradley, Commissioner

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REASONS FOR DECISION

Introduction

BC Gas Utility Ltd. ("BC Gas") filed an application dated February 5, 1997 (the “Application”) with the British Columbia Utilities Commission (the “Commission”, "BCUC") to establish the method for determining its revenue requirements and for approval to set rates for the five years ending December 31, 1998 to 2002.

On February 10, 1997, the Commission issued Order G-13-97 setting a pre-hearing conference to commence February 28, 1997. Following the pre-hearing conference, the Commission issued Order No. G-24-97 which included a regulatory timetable, setting a second pre-hearing conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. Subsequent to the second pre-hearing conference the Commission issued Order No. G-47-97 setting down a revised regulatory timetable which provided for, among other matters, rescheduling the public hearing to June 23, 1997. The timetable also provided for public workshops regarding the Application; a process for filing information requests by parties and responses by BC Gas; and an Alternative Dispute Resolution process ("ADR") to negotiate a settlement of issues related to the Application. BC Gas conducted public workshops on March 10, 11 and April 16, 1997. Information requests were filed and an additional 3 volumes of information responses and other data were provided by BC Gas.

The negotiation sessions commenced on June 2, 1997 and continued on various dates through to June 26, 1997 when a negotiated settlement was reached between BC Gas and the parties to the negotiation. The three year proposed settlement agreement was circulated to the ADR participants. Endorsements of the proposed settlement agreement by all of the ADR participants were received at the Commission by July 10, 1997. Subsequently, the proposed settlement agreement was circulated to all registered intervenors for comments by July 18, 1997 and no comments were received. The Commission panel for this proceeding also received a copy of the proposed settlement agreement and letters of endorsement.

The impact of the applied-for rates and the proposed settlement agreement on customer costs for natural gas service (gross margin) is as follows:

	1998	1999	2000	2001	2002
Rate Impact as a % of Gross Margin applied for in original application (May 5, 1997 revision)	6.40	3.40	2.70	1.90	1.60
Rate Impact as a % of Gross Margin (proposed settlement agreement)	1.85	2.00	2.00	N/A	N/A

The Commission notes that the participants expect that the gross margin rate impact on the Company's firm sales customers will be further reduced as a result of amortization of Gas Cost Reconciliation Account balances.

The Commission Panel has now reviewed the proposed settlement agreement as well as the letters of endorsement and comment from the ADR participants and has concluded that it should accept the settlement. Many of the elements within the proposed settlement agreement do not require special comment. However, the Commission did wish to express its views on several key issues that it noted in arriving at its decision and these Reasons for Decision provide those views.

Table 1 sets out key comparisons between the proposed settlement agreement and the Application as revised on May 5, 1997 by BC Gas.

Table 1
Key Aspects of proposed Settlement Agreement

	BC Gas Application	Proposed Settlement Agreement
Term	5 years	3 years
Productivity	1998 - 1% 1999 - 1% 2000 - 1%	1998 - 2% 1999 - 2% 2000 - 3%
Capital Structure	35%	33%
Capitalization of Overhead	1998 - 10.27% 1999 - 10.27% 2000 - 10.27%	1998 - 20% 1999 - 20% 2000 - 16%

The Commission has also created a new document called the Consolidated Settlement Document which incorporates editorial changes as proposed by BC Gas, and one other change as follows. In the subsection entitled "DSM Achievement Incentive" paragraph 6 originally read "The Company will apply to the Commission for funding of new programs where required". The Commission has changed this wording to "The Company will apply to the Commission for **program changes** where required". The Commission made the change as it concluded that the proposed wording may have arguably fettered the Commission in its discretion as provided for in the B.C. Utilities Commission Act.

Commission Comments on Key Issues:

Term

BC Gas applied for a five year term while the parties to the agreement agreed to a term of three years. The Commission considers a three year term is appropriate. It provides a long enough period to allow incentives to perform and at the same time balances the risks and other concerns with respect to changes that could occur over an extended period of time. The Commission is aware of some five year settlements which have been implemented for pipelines, but the Commission is of the view that the number of variables of change that can occur for a Local Distribution Company ("LDC") make it more appropriate to look at shorter terms. Pipelines typically have a limited number of shippers and more discrete cost projections.

Operating and Maintenance Costs ("O&M")

The formula used to develop O&M costs has been previously utilized in the settlements with respect to BC Gas and West Kootenay Power. From this experience, the Commission is satisfied that the methodology of adjusting a base cost for the growth in customers, productivity and inflation has provided appropriate targets for developing incentives. Attached to the Consolidated Settlement Document is a letter from Commission staff dated July 15, 1997 (Appendix B) which provides three examples of how productivity from capital projects will be eligible for inclusion within the O&M productivity targets.

Demand Side Management ("DSM")

The DSM Achievement Incentive represents the second time the Commission has endorsed a mechanism to pursue cost effective DSM resources. However, it is still a new feature in the regulatory environment and very little knowledge has yet been accumulated as to its success or failure. The Inland/Industrial group, in their letter of acceptance of the settlement, pointed out that "the settlement agreement should explain that the DSM programs and incentives are to be accounted for within the rate classes to which they relate." In the Commission's view, this is adequately covered in the settlement agreement, paragraph 9 in the subsection entitled "DSM Achievement Incentive".

Capital Efficiency Mechanism

This is the first significant capital efficiency mechanism that the Commission has approved. It is designed to provide an incentive for the utility to improve its costs of installing mains, services, meters and "other" plant. The range of incentive has been narrowed and the amount of the efficiency adjustment reduced from that originally filed in the Application. Due to the innovative nature of this particular mechanism, the Commission will be closely monitoring both the operation and results flowing from the use of the mechanism.

Overhead Capitalization

The Commission is in agreement with the move to reduce the capitalization of overheads from 22.5% to 16% over the three year period. The change is directionally correct in that a mature utility such as BC Gas should be lowering its overhead charges as capital projects are reduced as a proportion of total expenditures, and the customers that are benefiting from the capital projects are paying for them in an accelerated manner. The Commission also believes that, in undertaking and achieving the changes in overheads capitalization, the reductions should not lead to significant rate impacts.

Annual Review and Quality of Service

The Commission endorses the provision for an annual review. This allows the Commission to discharge its responsibility to maintain oversight of the utility and establish rates for each year. The Commission views the inclusion of service quality indicators as an important component of any incentive rate scheme. Such indicators ensure a utility will appropriately balance its obligation to provide safe, secure, high quality and non-discriminatory service to customers at the lowest rates possible while also providing an opportunity for shareholders to earn a fair return on their investment.

DATED at the City of Vancouver, in the Province of British Columbia this 25th day of July, 1997.

Original signed by:
Lorna R. Barr, Deputy Chair
and Acting Chair

Original signed by:
Ken L. Hall
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

CONSOLIDATED SETTLEMENT DOCUMENT
BC GAS UTILITY LTD. 1998 - 2000 REVENUE REQUIREMENTS

Background

BC Gas Utility Ltd. (“BC Gas") filed an application dated February 5, 1997 (the “Application”) with the British Columbia Utilities Commission (the “Commission”, "BCUC") to establish the method for determining its revenue requirements for the years 1998 to 2002.

On February 10, 1997, the Commission issued Order G-13-97 setting a pre-hearing conference to commence February 28, 1997. Following the pre-hearing conference, the Commission issued Order No. G-24-97 which included a regulatory agenda and timetable, setting a second pre-hearing conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. Subsequent to the second pre-hearing conference the Commission issued Order No. G-47-97 setting down a revised regulatory agenda and timetable rescheduling the public hearing to June 23, 1997. The regulatory agenda included public workshops regarding the Application; a process for filing information requests by parties and responses by BC Gas; and an Alternative Dispute Resolution process ("ADR") to negotiate settlement of issues related to the Application. BC Gas conducted public workshops on March 10, 11 and April 16. Information requests were filed and an additional 3 volumes of information responses and other data were provided by BC Gas.

The negotiation sessions commenced on June 2, 1997 and continued on various dates through to June 26, 1997. Parties represented during the settlement negotiations were BC Gas; Consumers Association of Canada (B.C.), B.C. Old Age Pensioners’ Organization, Council of Senior Citizen’s Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizen’s Association of B.C., West End Senior’s Network, and the End Legislative Poverty & Tenant’s Right Coalition, represented by the British Columbia Public Interest Advocacy Centre; Lower Mainland Large Volume Gas Users Association; R.T. O’Callaghan & Associates (not available for the final two negotiating sessions); Fording Coal Ltd.; Association for the Advancement of Sustainable Energy Policy; Cominco Ltd., Weyerhaeuser Canada Ltd. and Celgar Pulp Company; and British Columbia Utilities Commission Staff.

Multi-Year Settlement

This document sets out the terms of a three year settlement reached during the negotiations for setting the revenue requirements and rates of BC Gas. The margin and rate impacts arising from the settlement are summarized on the schedules in Appendix A. The impacts are estimates and are based on several assumptions (subject to vary in the manner as discussed below). These are subject to change each year and relate to factors including:

a) the rate of return on common equity
b) revenues
c) customer additions
d) taxes
e) inflation
f) short and long term debt interest rates
g) rate base additions
h) effect of capital efficiency mechanism
i) capital projects approved under applications for Certificate of Public Convenience and Necessity (CPCN’s)

The estimated gross margin impacts resulting from the settlement, as set out in Appendix A, are:

	1998		**1999**		**2000**	
	Core	Non-Core	Core	Non-Core	Core	Non-Core
Rate Impact as a % of Gross Margin	1.85	1.85	2.00	2.00	2.00	2.00

Based on the underlying assumptions, the gross margin rate impact on Core market customers are expected to be further reduced to about 0% in each year as a result of amortization of GCRA balances.

The settlement is the culmination of negotiations among parties who have many diverse interests. The settlement represents numerous compromises among the parties and consists of a settlement package from which no part can be severed. The issues resolved in the settlement negotiations are numerous and complex. Taken as a whole, the settlement represents a balance of interests and an overall consensus among the participating parties.

Term

The parties have agreed to a term of 3 years, namely the calendar years 1998, 1999 and 2000 (the "Term").

Productivity

Productivity shall be 2% in 1998, 2% in 1999 and 3% in 2000. References to "Productivity" in this document are references to those productivities except where stated otherwise.

Inflation

Several elements of the revenue requirement determination methodology are dependent on an inflation rate forecast. The forecast rate of inflation to be applied will be the consumer price index forecast for British Columbia.

The BC Gas proposal utilizing the forecasts for the next calendar year B.C. CPI by the Toronto-Dominion Bank, the Royal Bank of Canada, B.C. Ministry of Finance and the Conference Board of Canada (produced July to September) is accepted (hereinafter referred to as "forecast B.C. CPI").

References to "Inflation" in this document are references to this forecast of B.C. CPI except where stated otherwise.

Capital Structure

The common equity thickness for BC Gas will remain at 33%. In respect to its preference shares which are redeemable in 1999 and 2000, BC Gas will redeem such preference shares and replace the same with long term debt as redemption occurs.

Rate Of Return On Common Equity

The rate of return on common equity for BC Gas will be reset annually in accordance with the Commission's automatic rate of return adjustment mechanism.

Gas Costs

- The gas costs of BC Gas will be set in the manner currently approved by the Commission and customer rates will be adjusted in accordance with the currently approved gas cost allocation methodology.
- The Gas Cost Reconciliation Account will continue in the manner as approved by the Commission.
- The current Off System Incentive Plan will expire November 1, 1997. The parties agree to enter into discussions to determine the form of a successor gas cost incentive plan both for the short term and the long term. Any subsequent plan will be reviewed by interested parties before being submitted to the Commission for approval.

Revenues

- Both core market and non-core market revenues will be forecast each year in accordance with the methodologies employed by BC Gas and will be reviewed at the Annual Review before being submitted.
- The methodology for forecasting residential and commercial sales is established but industrial sales forecasts will be reviewed annually.
- The Rate Stabilization Adjustment Mechanism ("RSAM") will continue in the manner as approved by the Commission.
- Customer Additions will be forecast for each year of the Term, in accordance with the methodology employed by BC Gas and approved by the Commission.

Operating & Maintenance Costs ("O&M")

The O & M levels for each year of the Term will be determined in accordance with the following formula:

[Base Cost x (1 + Growth in Customers - Productivity) x (1 + Inflation)] + Cost of Defined Required Incremental Activities

Where:

Base Cost means: for 1998 this will be $142,760,000.

e.g., 1998 O&M level base cost $142,760,000 x (1 + 2.10% - 2.00%) x 1.01 = $144,334,000 allowed O&M for 1998 excluding DRIA for calculating the allowed O&M level for each subsequent year, the previous year's allowed O&M adjusted for projected actual customers will be the revised base to which customer growth, productivity and inflation will be added.

$$\text{e.g., 1999 O\&M level \$144,334,000} \times \frac{\text{1998 Projected Actual Customers}}{\text{1998 Forecast Customers}}$$

= revised base x formula = 1999 allowed O&M excl. DRIA

Growth in Customers means:	the forecast percentage growth in the average number of customers for the year over the previous year.
1998 Projected Actual Customers:	The estimate of actual average customers during 1998 at the November 1998 workshop
1998 Forecast Customers:	The forecast of average customers during 1998 at the November 1997 workshop.

In the event BC Gas files an application for a revenue requirement increase in 2001, the Base Cost O&M level to be reflected in rates for 2001, before any increase for inflation and growth in customers, will be that arising from 2000, subject to exogenous factors and DRIA.

Productivity and Retail Markets Downstream of the Meter (RMDM)

One instrument that the Company may use to achieve the targeted productivity gains is shedding, altering or reducing utility activities pursuant to the Commission’s policy on RMDM.

BC Gas will be entitled to capture the benefits of improved efficiencies, reduced costs, or other financial savings achieved through RMDM, for the duration of the test period. Adjustments in utility rates during the test period arising from RMDM will be limited to reflecting the reduction of services that had been previously included in customers’ bundled utility services. For further clarity the following hypothetical example distinguishes between improved efficiencies eligible for productivity and reduced services not eligible for productivity

Example:

BC Gas determines that outsourcing customer billing will reduce the cost of this function from $1.00/per customer to $0.79 and the third party will charge customers directly. The efficient gain of $0.21 is eligible for productivity but the rates will be rebased to reflect the $0.79 now paid directly to the third party.

O&M Productivity and Capital Projects

Improved efficiencies, reduced costs, or other financial savings achieved by BC Gas as a result of capital projects approved by the Commission pursuant to applications for Certificates of Public Convenience and Necessity may also be used by BC Gas to achieve the targeted O&M productivity levels.

DEMAND SIDE MANAGEMENT AND INCENTIVES

The Demand Side Management expenditure levels are forecast to remain constant over the Term, namely $1.624 million per year as a DRIA.

DSM Achievement Incentive

The following DSM Achievement Incentive is to be implemented. It is designed to encourage BC Gas to pursue cost effective demand side management resources.

1. Only energy efficiency programs are included in the mechanism.

2. A threshold level of 75% of the annual forecast gas savings must be achieved before any incentive is earned.

3. Calculation of incentive payments for gas savings greater than the threshold will be based on the net TRC benefits.

4. Recognizing that incremental energy savings become progressively more difficult to achieve, incentive payments will be earned according to the following schedule:

% of Annual Forecast GJ Savings	Before Tax Earnings as % of TRC Net Benefits
75% up to 100%	3%
100% and above	5%

5. DSM results (both positive and negative) from programs developed within the Utility but which at some point are moved outside the utility will be included in the DSM calculation where those program results are tracked by the Utility. This is consistent with the Company's goal of maximizing customer value in offering cost effective, competitive DSM services.

6. In order to maximize DSM efficiencies, BC Gas will be allowed to reallocate resources to modify existing programs, discontinue programs and develop new programs as the Company considers necessary. The Company will apply to the Commission for program changes where required.

7. A protocol for measuring DSM savings and TRC benefits needs to be established with the Commission and interested parties prior to the incentive mechanism taking effect.

8. The status of all DSM programs will be reviewed on a semi-annual basis with one of the reviews timed to coincide with the Annual Review of Service Quality Indicators.

9. The incentive mechanism will operate through the RSAM. The DSM Achievement Incentive operates outside of the Earnings Sharing Mechanism.

DSM Achievement Incentive Sample Calculations

Three cases are provided below representing the range of possible incentive payments for BC Gas achieving a minimum of 75% of forecast DSM gas savings.

Case A	Assuming:	75% of forecast gas savings achieved total TRC net benefits = $2,581,000
	Incentive = 3% of TRC net benefits (before tax) = $77,430	
Case B	Assuming:	100% of forecast gas savings achieved total TRC net benefits = $3,848,000
	Incentive = 5% of TRC net benefits (before tax) = $192,400	
Case C	Assuming:	110% of forecast gas savings achieved total TRC net benefits = $4,350,000
	Incentive = 5% of TRC net benefits (before tax) = $217,500	

Restructuring Deferral Account

A deferral account to record the costs incurred by BC Gas in restructuring its work force to achieve enhanced productivity is to be created and is to be effective upon the approval by the Commission of this settlement. The costs recorded in this deferral account will be recovered in customer rates. The deferral account will not exceed $3 million.

The amortization of this deferral account for restructuring costs will be no greater than $1 million for each year of the Term.

New Revenue Opportunities

The parties recognize that BC Gas should not be dis-incented from seeking legitimate new revenue opportunities which would serve to reduce future revenue deficiencies. To the extent such opportunities arise, but require expenditures greater than those arising from the formula, such revenues and expenditures will be addressed during the Annual Review each year.

Capital Expenditures

Capital expenditures for each year of the Term are established by class and by formula for certain of the classes. The classes are:

1. Mains - Recurring
2. Services - Recurring
3. Gas Measurement
4. Transmission Plant
5. System Improvements/Reinforcements
6. All Other Plant
7. Special Projects and CPCN's

Formulae for determining the expected capital expenditures for each year have been established for classes 1, 2, 3, 4, 5 and 6 as follows:

Note: the operation of the formulae for each class is shown for 1998 and 1999 and applies similarly to year 2000.

1. Mains - Recurring:

1998 Allowed Unit Cost =	Base Unit Cost x (1+ Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Service Additions x 21.6 metres of main per Service Addition
Where:	Base Unit cost = $25.03/metre main Service Additions = 95.1% of forecast Customer Additions
1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Service Additions x 21.6 metres of main per Service Addition

2. Services:

1998 Allowed Unit Cost =	Base Unit cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Service Additions
Where:	Base Unit cost = $884/Service Addition Service Additions = 95.1% of forecast Customer Additions
1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Service Additions

3. Meters:

1998 Allowed Unit Cost =	Base Unit cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x (Customer Additions + Meters Recalled)
Where:	Base Unit cost = $242/meter Customer Additions = forecast Customer Additions Meters Recalled = forecast of meters to be Recalled
1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x (Customer Additions + Meters Recalled)

4. Transmission Plant:

1998 Allowed Unit Cost =	Base Unit cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Transmission System Forecast Peak Day Throughput

Where:	Base Unit cost = $439.50/10^3m^3$ Transmission System Forecast Peak Day Throughput = forecast Transmission System Forecast Peak Day Throughput productivity = 1%

1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Transmission System Forecast Peak Day Throughput

5. System Improvements/Reinforcements:

1998 Allowed Unit Cost =	Base Unit Cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Customers End of Year ("EOY")
Where:	Base Unit cost = $6.52/customer EOY Customer EOY = forecast end of year total customers productivity = 1%

1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Customers EOY

6. All Other Plant:

The Allowed Costs for All Other Plant for each year of the Term will be set with an aggregate base level of $29,317,000 adjusted for Inflation each year less Productivity.

1998 Allowed Cost =	$29,317,000 x (1+ Inflation - Productivity)
1999 Allowed Cost =	1998 Allowed Cost x (1+ Inflation - Productivity)

BC Gas has divided its capital expenditures into 4 categories. They are:

A. Mains, Meters and Services
B. System Integrity and Reliability
C. All Other Plant
D. CPCN's and Special Projects

The costs related to each category will be identified by the accounts prescribed by the BCUC Code of Accounts and the Company's sub-accounts as follows:

	BCUC Account	**BC Gas Sub-Account**[(1)]
Category A		
Distribution Plant - Service Installations	473	xxx excl. 62X[(2)]
Distribution Plant - Meter and Regulator Installations	474	xxx
Distribution Plant - New Mains	475	640
Distribution Plant - Main Installations General	475	649
Distribution Plant - Meters	478	xxx
Category B		
LNG	440 - 449	xxx
Transmission Plant	460 - 469	xxx
Distribution Plant - Main Corrosion Control	475	653 TS[(3)]
Distribution Plant - System Improvements	475	657/659
Distribution Plant - Gate and Regulator Stations	477	671
Distribution Plant - Telemetry	477	672 TS[(3)]
Category C	All other BCUC Capital accounts and BC Gas sub-accounts	
Category D	N/A	N/A

(1) xxx includes all BC Gas sub-accounts in the BCUC account
(2) Account 473-62X- Distribution Plant Renewals and Alteration
(3) TS refers to charges from Technical Services to these Accounts

<u>Special Projects and CPCN's</u>

Special Projects and Certificate of Public Convenience and Necessity ("CPCN") projects are capital projects which BC Gas foresees as being required within the Term, but have not been developed sufficiently (certain of such projects were identified and described in the Application, they include: Southern Crossing, Automated Meter Reading, Single Vendor System, Interior LNG Satellite Facility, Customer Information Systems, Coastal Facilities, SCADA, muster stations), or projects which are not foreseen but could be required, such as the relocation of an urban transmission pipeline. Such projects are subject to approval by the Commission through applications for Certificates of Public Convenience and Necessity. To the extent such applications are approved and the capital projects undertaken, the capital project will form part of the rate base of BC Gas in the year following the year in which the capital project is completed. BC Gas will be entitled to accrue AFUDC on the expenditures associated with the capital project until the capital project is part of rate base.

BC Gas will be entitled to include the prudently incurred total capital expenditures and AFUDC in rate base at the commencement of the year following completion of the capital project.

Capital Efficiency Mechanism

BC Gas should be incented to employ capital more efficiently. A capital efficiency mechanism will operate as set out below. The categories in respect of which the mechanism will operate are categories A and C as described above.

To the extent the actual unit costs for a year vary from the Allowed Unit Costs for Category A, this difference is to be multiplied by the actual number of units (e.g. in the case of Mains - Recurring it would be actual metres of main installed for the year). This amount, together with the difference between the actual and allowed capital expenditures for that year in Category C, will form the basis for an efficiency adjustment to the utility rate base. This adjustment will be an aggregate dollar sum (the "Capital Efficiency Adjustment") which will be added or subtracted from the utility rate base. This mechanism will operate similarly in the case of positive and negative variances in unit costs.

The Capital Efficiency Incentive Adjustment to rate base will be phased out over three years. More specifically, in the immediately following year 66.7% of this variance will be an adjustment to the utility rate base and 33.3% in the subsequent year. This phasing will apply to each year of the Term so that the effect of variances in the second and third year of the Term will continue beyond the Term, e.g., phasing of the year 2000 variances will occur through the year 2002. For examples of the effect of the Capital Efficiency Mechanism, see Cases A1, B1, C1 and D1 in the response to Item 6 of Information Request No. 1 of the Inland Industrial Group (Volume 2, Tab E6).

Depreciation and Amortization Expense

The depreciation rates for BC Gas currently approved by the Commission will continue. BC Gas has indicated that it intends to file a depreciation study. The Commission will consider the study and any changes arising upon receipt and consideration of the study and the recommendation for changes in rates, if any, applied for by the Company.

Deferral Accounts

The following deferral accounts are to be continued or created:

- Continuation of the debt interest deferral accounts.
- Continuation of the NGV conversion grants deferral account for 1998 - 2000 to be amortized over three years.
- Revenue requirement hearing costs to be amortized over three years.
- DSM expenditures for 1998 - 2000 to be amortized over three years.
- IRP costs for 1998 - 2000 to be amortized over three years.
- Deferral of property tax expense variances from forecast and amortized in the following year. 1996/1997 credits amortized as per Appendix A.
- BC Hydro DRIA - amortization as per Appendix A.
- DSM DRIA - amortization as per Appendix A.
- Continuation of Coastal Facilities relocation costs deferral account.

- April 29, 1997 application for Phase 2 of BC 21 Power Smart costs - $303,000.
- Continuation of RSAM and GCRA accounts as described above.
- Deferral of restructuring costs as described above.

Further details of the deferral accounts are found in Appendix A.

Overhead Capitalization

Pursuant to a term of the 1996 and 1997 Negotiated Settlement, BC Gas filed a study on its overheads capitalization policy. The study recommended a significant reduction in the capitalization ratio. The impact of this study was to reduce overhead capitalization from 22.5% to 10.27% as shown in Volume 1, Section C, Tab 9-02 Revised (line 20) of the Application.

The BC Gas study and proposal is accepted, however, the capitalization ratios will be limited to 20%, 20%, and 16% for the years 1998, 1999 and 2000 respectively based on total Gross O&M excluding DRIA. The Company may apply for additional reductions in overheads capitalized in subsequent revenue requirement filings.

Taxes

Changes in taxes and similar costs will continue to be flowed through to customers with variances recorded in deferral accounts and amortized in rates in the following year.

The methodology for determination of the level of taxes for each year of the Term will be determined in the manner as specified in the Application, Volume 1, Section C Tabs 10 and 13 as revised.

Other Cost of Service Categories

All other categories of the cost of service not specifically referred to above will be determined in the manner as specified in the Application, Volume 1 as revised.

Exogenous Factors

During the Term, the BC Gas cost of service will be adjusted for exogenous factors (positive or negative) which are beyond the full control of the utility including: judicial, legislative or administrative changes, orders and directions; changes in generally accepted accounting principles and rules, catastrophic events, bypass or other similar events imposed on BC Gas which are not reflected in the rates of BC Gas.

Earnings Sharing Mechanism

BC Gas will share equally with its customers earnings variances (positive or negative) between the authorized level of earnings as determined annually under this settlement and the actual earnings of the utility net of specific incentive programs; namely, the capital efficiency mechanism, the gas supply incentive plan and the DSM Achievement Incentive all of which will be considered to be non-utility income for the purposes of calculating the earnings of the utility.

The operation of the Earnings Sharing Mechanism is illustrated in Volume 1, Section C, Tab 15 of the Application.

Annual Reviews and Rate Adjustments

BC Gas will conduct an Annual Review of the operation of the settlement and rate adjustments prior to January 1 of each year of the Term with the Commission, its staff and interested parties. The Annual Review is a "proceeding" for purposes of participant cost awards. This process will provide the Commission and all interested parties an opportunity to remain informed about the activities of the Company. The Annual Review will attempt to obtain consensus on issues which must be decided by the Commission in advance of each fiscal year for the matters related to setting the rates for each year of the Term.

At the annual workshop to be held in November of each of the years 1998 through 1999, BC Gas will present projections for the year that is ending and forecasts for the next year. The projections for the year that is ending will include:

- projected utility volumes and revenues
- projected utility expenses
- projected year-end plant balances and other rate base information
- projected deferral account balances and amortization
- projected year-end customers and other cost driver information
- projected utility earnings.

Forecasts for the next year will include:

- forecast customer growth
- forecasts of cost drivers, such as peak day throughput
- forecast Inflation
- forecast utility volumes and revenues
- forecast utility expenses (revised allowed costs)
- forecast utility capital expenditures (revised allowed costs)
- forecast plant balances, deferral account balances and amortization to be included in rates.

Cost drivers for the next year will be updated to reflect the forecasts relating to the year. Cost drivers for the next year will also be updated for projected variances between actual customer growth in the past year and the customer growth that had been forecast for that year.

Opening plant balances and other rate base items for the next year will be adjusted to reflect projected variances which are not included in the capital efficiency mechanism discussed above.

Service quality results will also be reviewed at the Annual Review.

BC Gas proposes to commence its workshops in November of 1997. At that workshop forecasts for 1998 will be presented, together with the projected number of customers as of January 1, 1998 and projected plant balances and other rate base information as of January 1, 1998. Cost drivers for 1998 will be updated to reflect the forecasts for 1998. Rates for 1998 will be set by the Commission based on the projected opening rate base for 1998 and the forecasts for 1998 as agreed upon by the participants or as subsequently determined by the Commission.

Prior to each annual workshop, BC Gas will provide interested parties and the Commission advance information regarding the projections and forecasts to be presented by BC Gas at the workshop. This should be done 3 weeks prior to the workshop to allow parties to submit information requests and receive responses prior to the workshops.

In regard to projected year-end earnings, projected year end capital unit costs related to capital incentives presented for rate-making purposes in the November workshop BC Gas will provide an update in April or May once actual results have been determined and adjustments will be made at the following year end. Incentives will be trued up to the actual results at that time.

Service Quality Indicators

Principle:

Maintenance of existing high levels of service quality is an important feature of this Settlement. However, it is recognized that variance in these statistics may occur due to random events or events beyond the full control of BC Gas.

Process:

- Service Quality Indicators will be reviewed at the Annual Review in November of each year.

- Participants will be given an opportunity to argue whether a deviation from the benchmark for any of the Service Quality Indicators is significant enough to establish that service quality is deteriorating generally or in specific areas.

- For those concerns which are not resolved at the review, participants will retain the option to make submissions to the Commission that it should limit the payments which BC Gas might otherwise earn from the financial incentives in this Settlement.

Service Quality Indicators:

1. Response time to emergency calls[1].
2. Response time for answering service centre calls by a person.
3. Leaks per kilometre of distribution mains due to system deterioration.
4. Transmission system annual reportable incidents.
5. Number of third party distribution system damage incidents per 1000 housing starts[2].

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[1] Applies to Coastal region only. Data for 1994 and 1995 not available. Measure for Interior region will be determined at a later date.

[2] Data for 1994 is not available. Initial benchmark will be set using 2 years of data.

Annual Evaluation:

- Unless otherwise indicated, *benchmarks* will be calculated as the rolling average of the three years prior to the most current year; *performance indicators* will be calculated as the rolling average of the most current year plus the past two years.

- Each performance indicator will be evaluated on its own merits and a material deviation from the benchmark for any single performance indicator is sufficient basis to argue service quality deterioration and the need to limit payments to BC Gas.

- Each performance indicator will be given equal weight.

- The onus of establishing that a benchmark has been met or why it is reasonable that it was not met rests with the utility.

- Interested parties should have access to the service quality evaluation prior to the Annual Review.

- Any party may argue that the benchmarks need to be modified

Appendix A

1998 - 2002 Revenue Requirements Settlement

Illustrative Rate Impacts Summary

BC GAS UTILITY LTD.
SUMMARY
FOR THE YEARS 1998 TO 2000
($000)

APPENDIX A
1998-2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
SUMMARY

Particulars (1)	Volume 1 (Rev.) (2)	Difference (3)	1998-2000 Settlement (4)
1998			
Rate Base	$ 1,581,623	$ (12,734)	$ 1,568,889
Revenue Requirement	$ 24,448	$ (17,552)	$ 6,896
% Gross Margin Increase	6.37%	-4.57%	1.80%
Gross Margin (incl. Increase)	$ 408,468	$ (17,552)	$ 390,916
Operation and Maintenance			
Gross O&M excl. BC Hydro Costs	$ 136,057	$ (2,273)	$ 133,784
O&M Expense (Net)	$ 133,335	$ (16,244)	$ 117,091
Plant Additions			
- Capital Expenditures	$ 93,474	$ (8,782)	$ 84,692
- Overheads Capitalized	15,075	13,792	28,867
- All Other (WIP etc.)	2,445	0	2,445
Total	$ 110,994	$ 5,010	$ 116,004
1999			
Rate Base	$ 1,635,694	$ (4,125)	$ 1,631,569
Revenue Requirement	$ 14,278	$ (6,570)	$ 7,708
% Gross Margin Increase	3.44%	-1.50%	1.94%
Gross Margin (incl. Increase)	$ 429,512	$ (24,421)	$ 405,091
Operation and Maintenance			
Gross O&M excl. BC Hydro Costs	$ 139,981	$ (4,638)	$ 135,343
O&M Expense (Net)	$ 137,133	$ (18,696)	$ 118,437
Plant Additions			
- Capital Expenditures	$ 95,829	$ (9,241)	$ 86,588
- Overheads Capitalized	15,510	13,693	29,203
- All Other (WIP etc.)	8,420	0	8,420
Total	$ 119,759	$ 4,452	$ 124,211
2000			
Rate Base	$ 1,703,373	$ (16,436)	$ 1,686,937
Revenue Requirement	$ 11,984	$ (3,961)	$ 8,023
% Gross Margin Increase	2.73%	-0.79%	1.94%
Gross Margin (incl. Increase)	$ 450,229	$ (28,891)	$ 421,338
Operation and Maintenance			
Gross O&M excl. BC Hydro Costs	$ 144,106	$ (8,468)	$ 135,638
O&M Expense (Net)	$ 141,126	$ (16,581)	$ 124,545
Plant Additions			
- Capital Expenditures	$ 135,013	$ (47,670)	$ 87,343
- Overheads Capitalized	15,967	7,446	23,413
- All Other(WIP etc.)	140	0	140
Total	$ 151,120	$ (40,224)	$ 110,896

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1999
($000)

APPENDIX A
1998 - 2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS

	1998				1999			
	--- Captive ---				--- Captive ---			
	Core	Non-Core	Non-Captive	Total	Core	Non-Core	Non Captive	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
RATE INCREASE REQUIRED								
Gas Sales and Transportation Revenue,								
At Prior Year's Rates	$721,248	$33,574	$15,139	$769,961	$742,055	$33,520	$15,108	$790,683
Add - Other Revenue Related to Burrard								
Thermal / Centra BC (PCEC)	0	336	8,806	9,142	0	336	8,888	9,224
Total Revenue	721,248	33,910	23,945	779,103	742,055	33,856	23,996	799,907
Less - Cost of Gas	(376,727)	(6,192)	(12,164)	(395,083)	(383,994)	(6,366)	(12,164)	(402,524)
Gross Margin	$344,521	$27,718	$11,781	$384,020	$358,061	$27,490	$11,832	$397,383
	========	=======	=======	======	=======	=======	=======	=======
Revenue Deficiency-Volume 1 (Rev)	$22,628	$1,820	$0	$24,448	$13,260	$1,018	$0	$14,278
Difference	(16,245)	(1,307)	0	(17,552)	(6,102)	(468)	0	(6,570)
Revenue Deficiency								
- 1998-2000 Settlement	6,383	513	0	6,896	7,158	550	0	7,708
Refund of Deferred Gas Cost								
Credits (GCRA)	0	0	0	0	0	0	0	0
	$6,383	$513	$0	$6,896	$7,158	$550	$0	$7,708
	========	=======	=======	======	=======	=======	=======	=======
Rate Increase as a % of Gross Margin	1.85%	1.85%	0.00%	1.80%	2.00%	2.00%	0.00%	1.94%
	========	=======	=======	======	=======	=======	=======	=======
Rate Increase as a % of Total Revenue	0.88%	1.51%	0.00%	0.89%	0.96%	1.62%	0. 00%	0.96%
	========	=======	=======	======	=======	=======	=======	=======

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ILLUSTRATIVE RATE IMPACTS
PAGE 01-01.1
2000

Particulars	----- Captive ---- Core	Non-Core	Non-Captive	Total
(1)	(2)	(3)	(4)	(5)
RATE INCREASE REQUIRED				
Gas Sales and Transportation Revenue, At Prior Year's Rates	$765,421	$34,282	$15,082	$814,785
Add - Other Revenue Related to Burrard Thermal / Centra BC (PCEC)	0	336	8,885	9,221
Total Revenue	765,421	34,618	23,967	824,006
Less - Cost of Gas	(392,051)	(6,476)	(12,164)	(410,691)
Gross Margin	$373,370	$28,142	$11,803	$413,315
	========	=======	=======	========
Revenue Deficiency - Volume 1 (Rev.)	$11,144	$840	$0	$11,984
Difference	(3,683)	(278)	0	(3,961)
Revenue Deficiency - 1998-2000 Settlement	7,461	562	0	8,023
Refund of Deferred Gas Cost Credits (GCRA)	0	0	0	0
	$7,461	$562	$0	$8,023
	========	=======	=======	=======
Rate Increase as a % of Gross Margin	2.00%	2.00%	0.00%	1.94%
	========	=======	=======	========
Rate Increase as a % of Total Revenue	0.97%	1.62%	0.00%	0,97%
	========	=======	=======	========

	1998			1999			2000		
Description	Present Rates	Adj	Revised Rates	1998 Rates	Adj	Revised Rates	1999 Rates	Adj	Revised Rates
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Plant in Service, Beginning	$1,842,973	$0	$1,842,973	$1,949,177	$0	$1,949,177	$2,063,288	$0	$2,063,288
Additions	116,004	0	116,004	124 211	0	124 211	110 896	0	110,896
Disposals	(9,800)	0	(9,800)	(10,100)	0	(10,100)	(10,400)	0	(10,400)
Plant in Service, Ending	1,949,177	0	1,949,177	2,063,288	0	2,063,288	2,163,784	0	2,163,784
Add - Intangible Plant	967	0	967	967	0	967	967	0	967
	1,950,144	0	1,950,144	2,064,255	0	2,064,255	2,164,751	0	2,164,751
Contributions In Aid of Construction	(73,964)	0	(73,964)	(87,518)	0	(87,518)	(102,314)	0	(102,314)
Less - Accumulated Depreciation	(314,089)	0	(314,089)	(357,976)	0	(357,976)	(405,567)	0	(405,567)
Net Plant in Service, Ending	$1,562,091	$0	$1,562,091	$1,618,761	$0	$1,618,761	$1,656,870	$0	$1,656,870
Net Plant in Service, Beginning	$1,508,239	$0	$1,508,239	$1,562,091	$0	$1,562,091	$1,618,761	$0	$1,618,761
Net Plant in Service, Mid-Year	$1,535,165	$0	$1,535,165	$1,590,426	$0	$1,590,426	$1,637,816	$0	$1,637,816
Adjustment to 13-Month Average	0	0	0	0	0	0	0		0
Construction Advances	(3,114)	0	(3,114)	(2,336)	0	(2,336)	(1,557)	0	(1,557)
Work in Progress, No AFUDC	4,048	0	4,048	4 333	0	4,333	3,833	0	3,833
Unamortized Deferred Charges	(7,215)	0	(7,215)	(1 384)	0	(1,384)	4,167	0	4,167
Cash Working Capital	10,024	71	10,095	10,401	(106)	10,295	10,881	40	10,921
Other Working Capital	29,910	0	29,910	30,235	0	30,235	31,757	0	31,757
Utility Rate Base	$1,568,818	$71	$1,568,889	$1,631,675	(106)	$1,631,569	$1,686,897	40	$1,686,937

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
($000)

	1998			1999			2000		
		-Revised Rates-			-Revised Rates-			-Revised Rates-	
Particulars	Present Rates	Revised Revenue	Total	1998 Rates	Revised Revenue	Total	1999 Rates	Revised Revenue	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ENERGY VOLUMES (TJ)									
Sales	158,624	0	158,624	161,357	0	161,357	164,379	0	164,379
Transportation	80,626	0	80,626	79,741	0	79,741	80,616	0	80,616
	239,250	0	239,250	241,098	0	241,098	244,995	0	244,995
Average Rate per GJ									
Sales	$4.680		$4.720	$4.731		$4.776	$4.788		$4.833
Transportation	$0.343		$0.348	$0.342		$0.348	$0.345		$0.351
Average	$3.218		$3.247	$3.280		$3.311	$3.326		$3.358
UTILITY REVENUE									
Sales - Present Rates	$742,344	$0	$742,344	$763,426	$0	$763,426	$786,984	$0	$786,984
- Increase	0	6,436	6,436	0	7,220	7,220	0	7,526	7,526
Transportation									
- Present Rates	27,617	0	27,617	27,257	0	27,257	27,801	0	27,801
- Increase	0	460	460	0	489	489	0	502	502
Total	769,961	6,896	776,857	790,683	7,708	798,391	814,785	8,023	822,808
Cost of Gas Sold									
(Including Gas Lost)	395,083	0	395,083	402,524	0	402,524	410,691	0	410,691
Gross Margin	374,878	6,896	381,774	388,159	7,708	395,867	404,094	8,023	412,117
Restructuring Costs Amort.	555	0	555	555	0	555	555	0	555
Operation and Maintenance	117,091	0	117,091	118,437	0	118,437	124,545	0	124,545
Vehicle and FIS Leases	2,269	0	2,269	2,309	0	2,309	2,346	0	2,346
Property and Sundry Taxes	31,210	0	31,210	32,227	(1)	32,226	34,577	0	34,577
Depreciation and Amortization	54,904	0	54,904	58,799	0	58,799	61,801	0	61,801
Other Operating Revenue	(14,169)	0	(14,169)	(14,399)	0	(14,399)	(14,545)	0	(14,545)
	191,860	0	191,860	197,928	(1)	197,927	209,279	0	209,279
Utility Income Before Taxes	183,018	6,896	189,914	190,231	7,709	197,940	194,815	8,023	202,838
Income Taxes	49,878	3,072	52,950	53,054	3,429	56,483	53,693	3,562	57,255
EARNED RETURN	$133,140	3,824	$136,964	$137,177	4,280	$141,457	$141,122	$4,461	$145,583
UTILITY RATE BASE	$1,568,818	$71	$1,568,889	$1,631,675	($106)	1,631,569	1,686,897	$40	1,686,937
RATE OF RETURN ON									
UTILITY RATE BASE	8.49%		8.73%	8.41%		8.67%	8.37%		8.63%

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
($000)

		1998			1999			2000	
		-Revised Rates-			-Revised Rates-			-Revised Rates-	
Particulars	Present Rates	Revised Revenue	Total	1998 Rates	Revised Revenue	Total	1999 Rates	Revised Revenue	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
CALCULATION OF INCOME TAXES									
Earned Return	$133 140	$3,824	$136,964	$137,177	$4,280	$141,457	$141,122	$4,461	$145,583
Deduct -Interest on Debt	(73,711)	5	(73,706)	(77,441)	(4)	(77,445)	(84,252)	(17)	(84,269)
Add- Non-Tax Ded. Expense (Net)	4,435	0	4,435	5,317	0	5,317	4,315	0	4,315
Accounting Income After Tax	63,864	3,829	67,693	65,053	4,276	69,329	61,185	4,444	65,629
Add (Deduct) - Timing Differences	(9,757)	0	(9,757)	(7,309)	0	(7,309)	(2,875)	0	(2,875)
Add - Large Corporation Tax	2,440	(76)	2,364	2,508	(86)	2,422	2,597	(90)	2,507
Taxable Income After Tax	$56,547	$3,753	$60,300	$60,252	$4,190	$64,442	$60,907	$4,354	$65,261
Income Tax Rate(Current Tax)	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%
1 - Current Income Tax Rate	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%
Taxable Income (L10 : L14)	$103,985	$6,901	$110,886	$110,798	$7,705	$118,503	$112,003	$8,006	$120,009
Income Tax-Current (L18xL13)	$47,438	$3,148	$50,586	$50,546	$3,515	$54,061	$51,096	$3,652	$54,748
- Large Corporation Tax	2,440	(76)	2,364	2,508	(86)	2,422	2,597	(90)	2,507
Total	$49,878	$3,072	$52,950	$53,054	$3,429	$56,483	$53,693	$3,562	$57,255
REVENUE DEFICIENCY									
Earned Return		$3,824	$136,964		$4,280	$141,457		$4,461	$145,583
Add - Income Taxes		3,072	52,950		3,429	56,483		3,562	57,255
Deduct - Utility Income Before Taxes, Present Rates		0	(183,018)		0	(190,231)		0	(194,815)
Corporate Capital Tax		0	0		(1)	(1)		0	0
Deficiency After Corporate Capital Tax		$6,896	$6,896		$7,708	$7,708		$8,023	$8,023

RETURN ON CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
($000)

ILLUSTRATIVE RATE IMPACTS

Particulars	Reference	---- Capitalization ---- Amount	%	Embedded Cost	Average Cost Component	Earned Return
1998 PRESENT RATES						
Long-Term Debt		$692,562	44.15%	9.420X	4.16X	
Unfunded Debt		211,701	13.49%	4.000%	0.54%	
Preference Shares		146,845	9.36%	6.995%	0.65%	
Common Equity		517,710	33.00%	9.515%	3.14%	
		$1,568,818	100.00%		8.49%	
1998 REVISED RATES						
Long-Term Debt		$692,562	44.14%	9.420%	4.16%	$65,239
Unfunded Debt	$211,701					
Adjustment, Revised Rates	48	211,749	13.50%	4.000%	0.54%	8,470
Preference Shares		146,845	9.36%	6.995%	0.65%	10,272
Common Equity		517,733	33.00%	10.250%	3.38%	53,068
		$1,568,889	100.00%		8.73%	$137,049
1999 AT 1998 RATES						
Long-Term Debt		$734 940	45.04%	9.288%	4.18%	
Unfunded Debt		229,546	14.07%	4.000%	0.56%	
Preference Shares		128,736	7.89%	6.946%	0.55%	
Common Equity		538,453	33.00%	9.455%	3.12%	
		$1,631,675	100.00%		8.41%	
1999 REVISED RATES						
Long-Term Debt		$734,940	45.05%	9.288%	4.18%	$68,261
Unfunded Debt	$229,546					
Adjustment, Revised Rates	(71)	229,475	14.06%	4.000%	0.56%	9,179
Preference Shares		128,736	7.89%	6.946%	0.55%	8,942
Common Equity		538,418	33.00%	10.250%	3.38%	55,188
		$1,631,569	100.00%		8.67%	$141,570

2000 AT 1999 RATES						
Long-Term Debt		$828,322	49.10%	9.016%	4.43%	
Unfunded Debt		239 399	14.19%	4.000%	0 57%	
Preference Shares		62 500	3.71%	6.631%	0 25%	
Common Equity		556,676	33.00%	9.455%	3.12%	
		$1,686,897	100.00%		8.37%	
2000 REVISED RATES						
Long-Term Debt		$828,322	49.11%	9.016%	4.43%	$74,682
Unfunded Debt	$239,399					
Adjustment, Revised Rates	27	239,426	14.19%	4.000%	0.57%	9,577
Preference Shares		62,500	3.70%	6.631%	0.25%	4,144
Common Equity		556,689	33.00%	10.250%	3.38%	57,061
		$1,686,937	100.00%		8.63%	$145,464

BC GAS UTILITY LTD
TARGET COSTS - CAPITAL EXPENDITURE SUMMARY
FOR THE YEARS ENDING DECEMBER 31, 1998 TO 2000
($000)

Particulars		Target Costs		
	Base Cost	1998	1999	2000
(1)	(2)	(3)	(4)	(5)
SUMMARY - TOTAL COST				
CATEGORY:				
A: MAINS, SERVICES & METERS	$35,204	$36,246	$37,652	$38,445
B: SYSTEM INTEGRITY AND RELIABILITY	18,545	18,805	18,948	18,850
C: ALL OTHER PLANT	29,317	29,641	29,988	30,048
TOTAL - CATEGORIES A, B & C	83,066	84,692	86,588	87,343
D: SPECIAL PROJECTS 2300	0	0	0	0
8400	0	0	0	0
MISC.	0	0	0	0
TOTAL CAPITAL EXPENDITURES	83,066	84,692	86,588	87,343
TOTAL PER 1998-2002 VOL. 1, PAGE 03-04 (REV)	89,908	93,474	95,829	135,013
INCREASE (DECREASE)	($6,842)	($8,782)	($9,241)	($47,670)
TOTAL CAPITAL EXPENDITURES - REAL ($1997)	$83,066	$83,853	$84,882	$84,774

CAPITAL EXPENDITURE/PLANT ADDITIONS SUMMARY 1998 - 2000 SETTLEMENT

BC GAS UTILITY LTD. ILLUSTRATIVE RATE IMPACTS

($000) PAGE 03-05

Particulars	Base Cost	Target Costs 1998	1999	2000
(1)	(2)	(3)	(4)	(5)
CAPITAL EXPENDITURES				
A: MAINS, SERVICES & METERS	$35,204	$36,246	$37,652	$38,445
B: SYSTEM INTEGRITY AND RELIABILITY	18,545	18,805	18,948	18,850
C: ALL OTHER PLANT	29,317	29,641	29,988	30,048
D: SPECIAL PROJECTS	0	0	0	0
TOTAL CAPITAL EXPENDITURES	83,066	84,692	86,588	87,343
WORK IN PROGRESS				
Add - Opening WIP		16,100	15,205	8,380
Less - Closing WIP		(15,205)	(8,380)	(9,770)
Add - AFUDC		1,550	1,595	1,530
Add - O'H Capitalized		28,867	29,203	23,413
SUBTOTAL - PLANT ADDITIONS		116,004	124,211	110,896
Add - 1996 and 1997 CPCN's		6,618		.
TOTAL PLANT ADDITIONS		122,622	124,211	110,896
TOTAL PER 1998 - 2002 VOL. 1, PAGE 03-05 (REV.)		117,612	119,759	151,120
INCREASE (DECREASE)		$5,010	$4,452	($40,224)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1998
($000)

Particulars	Account	Forecast Balance 12/31/97	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/98	Mid-Year Average 1998
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Deferred Interest	#179-008	$0	$0	$0	$0	$0	$0	$0	$0
Market Rebate Incentive									
- Water Heater Grants	#179-052	402	0	0	0	(100)	0	302	352
- Commercial & Multi-Family	#179-013	103	0	0	0	(55)	0	48	75
NGV Conversion Grants	#179-018	20	0	0	0	(20)	0	0	10
NGV Conversion Grants 1996-1997		1,534	0	0	0	(527)	0	1,007	1,271
NGV Conversion Grants 1998-2002		0	1,500	(668)	832	0	0	832	416
Local Gas Development	#179-053	2,908	0	(90)	(90)	(564)	0	2,254	2,581
Fraser Valley Gas Exploration	#179-092	457	0	0	0	(91)	0	366	411
Revenue Req. Hearing-1998-2002	179-141	133	0	0	0	(44)	0	89	111
Demand Side Management G-69-93	179-063	45	0	0	0	(33)	0	12	28
Demand Side Management 1996-97		327	0	0	0	(110)	0	217	272
Demand Side Management 1998-2002		0	1,585	(705)	880	0	0	880	440
Integrated Resource Plan G-69-93	179-064	133	0	0	0	(77)	0	56	94
Integrated Resource Plan G-60-94		147	0	0	0	(49)	0	98	123
Integrated Resource Plan 1996-97		108	0	0	0	(36)	0	72	90
Integrated Resource Plan 1998-2002		0	100	(45)	55	0	0	55	28
Residential Thermostat Program	#179-109	30	0	0	0	(11)	0	19	24
Property Tax Deferral	#179-062	(890)	0	0	0	0	0	(890)	(890)
Westar Receivable	#179-069	134	0	0	0	(27)	0	107	121

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION 1998
FOR THE YEAR ENDED DECEMBER 31, 1998 PAGE 03-11.2
($000)

Particulars (1)	Account (2)	Forecast Balance 12/31/97 (3)	Gross Additions (4)	Less-Taxes (5)	Net Additions (6)	Amortization Expense (7)	Amortization Other (8)	Balance 12/31/98 (9)	Mid-Year Average 1998 (10)
G.C.R.A.	#179-088	(13,500)	0	0	0	0	4,500	(9,000)	(11,250)
G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
Offsystem Sales Coord. Center	179-120	23	0	0	0	(10)	0	13	18
Revelstoke Propane Cost	#279-024	293	0	0	0	0	(293)	0	147
B.C. Hydro DRIA	#179-144	(823)	0	0	0	0	0	(823)	(823)
DSM DRIA	#179-142	(489)	0	0	0	0	0	(489)	(489)
Recovery of Non-Utility Service	#279-063	(98)	0	0	0	98	0	0	(49)
RSAM	#179-089	(7,500)	0	0	0	0	2,500	(5,000)	(6,250)
NGV B.C. Transit Grants	#179-105	461	0	0	0	(159)	0	302	382
BC21 Power Smart Program	#179-119	444	0	0	0	(222)	0	222	333
BC21 Power Smart Phase 2		168	0	0	0	(34)	0	134	151
Coastal Facilities (#C-6-95)									
- Relocation		2,387	1,049	(467)	582	(686)	0	2,283	2,335
- Lochburn NBV Amortization		1,108	0	0	0	(369)	0	739	924
- Fraser Valley NBV Amortization		878	0	0	0	(176)	0	702	790
Organizational Restructuring	#179-132	480	0	0	0	(96)	0	384	432
Non-Core Margin Deferral	#179-135	214	0	0	0	0	(214)	0	107
Main Extension Hearing Costs	#179-138	18	0	0	0	(18)	0	0	9
1995 IRP Participant A~ards	#179-140	7	0	0	0	(7)	0	0	4
Gain on Sale of Kamloops Property	279-001	(193)	0	0	0	193	0	0	(97)
Restructuring Costs		0	3,000	(1,335)	1,665	(555)	0	1,110	555
Total Deferred Charges for Rate Base		($10,531)	$7,234	($3,310)	3,924	($3,785)	$6,493	($3,899)	($7,215)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1999
($000)

Particulars	Account	Forecast Balance 12/31/98	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/99	Mid-Year Average 1999
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Deferred Interest	#179-008	$0	$0	$0	$0	$0	$0	$0	$0
Market Rebate Incentive									
- Water Heater Grants	#179-052	302	0	0	0	(100)	0	202	252
- Commercial & Multi-Family	179-013	48	0	0	0	(48)	0	0	24
NGV Conversion Grants	#179-018	0	0	0	0	0	0	0	0
NGV Conversion Grants	1996-1997	1,007	0	0	0	(527)	0	480	743
NGV Conversion Grants	1998-2002	832	1,500	(668)	832	(277)	0	1,387	1,109
Local Gas Development	#179-053	2,254	0	(81)	(81)	(544)	0	1,629	1,942
Fraser Valley Gas Exploration	179-092	366	0	0	0	(91)	0	275	320
Revenue Req. Hearing-1998-2002	179-141	89	0	0	0	(44)	0	45	67
Demand Side Management G-69-93	179-063	12	0	0	0	(12)	0	0	6
Demand Side Management 1996-97		217	0	0	0	(109)	0	108	163
Demand Side Management 1998-2002		880	1,585	(705)	880	(293)	0	1,467	1,174
Integrated Resource Plan G-69-93	179-064	56	0	0	0	(56)	0	0	28
Integrated Resource Plan #G-60-94		98	0	0	0	(49)	0	49	73
Integrated Resource Plan 1996-97		72	0	0	0	(36)	0	36	54
Integrated Resource Plan 1998-2002		55	100	(45)	55	(18)	0	92	74
Residential Thermostat Program	#179-109	19	0	0	0	(11)	0	8	14
Property Tax Deferral	#179-062	(890)	0	0	0	0	429	(461)	(676)
Westar Receivable	#179-069	107	0	0	0	(26)	0	81	93

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION 1998 - 2000 SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 1999 1999
($000) PAGE 03-11.4

Particulars (1)	Account (2)	Forecast Balance 12/31/98 (3)	Gross Additions (4)	Less-Taxes (5)	Net Additions (6)	Amortization Expense (7)	Amortization Other (8)	Balance 12/31/99 (9)	Mid-Year Average 1999 (10)
G.C.R.A.	#179-088	(9,000)	0	0	0	0	4,500	(4,500)	(6,750)
G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
Offsystem Sales Coor. Center	#179-120	13	0	0	0	(13)	0	0	7
Revelstoke Propane Cost	#279-024	0	0	0	0	0	0	0	0
B.C. Hydro DRIA	#179-144	(823)	0	0	0	0	0	(823)	(823)
DSM DRIA	#179-142	(489)	0	0	0	0	0	(489)	(489)
Recovery of Non-Utility Service	279-063	0	0	0	0	0	0	0	0
RSAM	#179-089	(5,000)	0	0	0	0	2,500	(2,500)	(3,750)
NGV B.C. Transit Grants	#179-105	302	0	0	0	(159)	0	143	223
BC21 Power Smart Program	#179-119	222	0	0	0	(222)	0	0	111
BC21 Power Smart Phase 2		134	0	0	0	(34)	0	100	117
Coastal Facilities (#C-6-95)									
- Relocation		2,283	1,049	(467)	582	(802)	0	2,063	2,173
- Lochburn NBV Amortization		739	0	0	0	(369)	0	370	555
- Fraser Valley NBV Amortization		702	0	0	0	(176)	0	526	614
Organizational Restructuring	#179-132	384	0	0	0	(96)	0	288	336
Non-Core Margin Deferral	#179-135	0	0	0	0	0	0	0	0
Main Extension Hearing Costs	#179-138	0	0	0	0	0	0	0	0
1995 IRP Participant Awards	#179-140	0	0	0	0	0	0	0	0
Gain on Sale of Kamloops Property	#279-001	0	0	0	0	0	0	0	0
Restructuring Costs		1,110	0	0	0	(555)	0	555	833
Total Deferred Charges for Rate Base		($3,899)	$4,234	($1,966)	2,268	($4,667)	$7,429	$1,131	($1,384)
		======	======	======	=====	======	======	======	======

($000) PAGE 03-11.5

Particulars	Account	Forecast Balance 12/31/99	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/00	Mid-Year Average 2000
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Deferred Interest	#179-008	$0	$0	$0	$0	$0	$0	$0	$0
Market Rebate Incentive									
- Water Heater Grants	#179-052	202	0	0	0	(100)	0	102	152
- Commercial & Multi-Family	179-013	0	0	0	0	(42)	0	(42)	(21)
NGV Conversion Grants	#179-018	0	0	0	0	0	0	0	0
NGV Conversion Grants	1996-1997	480	0	0	0	(480)	0	0	240
NGV Conversion Grants	1998-2002	1,387	1,500	(668)	832	(555)	0	1,664	1,526
Local Gas Development	#179-053	1,629	0	(73)	(73)	(520)	0	1,036	1,332
Fraser Valley Gas Exploration	179-092	275	0	0	0	(91)	0	184	230
Revenue Req. Hearing-1998-2002	179-141	45	0	0	0	(45)	0	0	23
Demand Side Management G-69-93	179-063	0	0	0	0	0	0	0	0
Demand Side Management 1996-97		108	0	0	0	(108)	0	0	54
Demand Side Management 1998-2002		1,467	1,585	(705)	880	(587)	0	1,760	1,613
Integrated Resource Plan G-69-93	179-064	0	0	0	0	0	0	0	0
Integrated Resource Plan #G-60-94		49	0	0	0	(49)	0	0	25
Integrated Resource Plan 1996-97		36	0	0	0	(36)	0	0	18
Integrated Resource Plan 1998-2002		92	100	(45)	55	(37)	0	110	100
Residential Thermostat Program	#179-109	8	0	0	0	(8)	0	0	4
Property Tax Deferral	#179-062	(461)	0	0	0	0	461	0	(231)
Westar Receivable	#179-069	81	0	0	0	(27)	0	54	68

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION 1998 - 2000 SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2000 2000
($000) PAGE 03-11.6

Particulars	Account	Forecast Balance 12/31/99	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/009	Mid-Year Average 2000
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
G.C.R.A.	#179-088	(4,500)	0	0	0	0	4,500	0	(2,250)
G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
Offsystem Sales Coor. Center	#179-120	0	0	0	0	0	0	0	0
Revelstoke Propane Cost	#279-024	0	0	0	0	0	0	0	0
B.C. Hydro DRIA	#179-144	(823)	0	0	0	823	0	0	(412)
DSM DRIA	#179-142	(489)	0	0	0	489	0	0	(245)
Recovery of Non-Utility Service	279-063	0	0	0	0	0	0	0	0
RSAM	#179-089	(2,500)	0	0	0	0	2,500	0	(1,250)
NGV B.C. Transit Grants	#179-105	143	0	0	0	(143)	0	0	71
BC21 Power Smart Program	#179-119	0	0	0	0	0	0	0	0
BC21 Power Smart Phase 2		100	0	0	0	(34)	0	66	83
Coastal Facilities (#C-6-95)									
- Relocation		2,063	1,049	(467)	582	(918)	0	1,727	1,895
- Lochburn NBV Amortization		370	0	0	0	(370)	0	0	185
- Fraser Valley NBV Amortization		526	0	0	0	(176)	0	350	438
Organizational Restructuring	#179-132	288	0	0	0	(96)	0	192	240
Non-Core Margin Deferral	#179-135	0	0	0	0	0	0	0	0
Main Extension Hearing Costs	#179-138	0	0	0	0	0	0	0	0
1995 IRP Participant Awards	#179-140	0	0	0	0	0	0	0	0
Gain on Sale of Kamloops Property	#279-001	0	0	0	0	0	0	0	0
Restructuring Costs		555	0	0	0	(555)	0	555	278
Total Deferred Charges for Rate Base		($1,131)	$4,234	($1,958)	2,276	($3,665)	$7,461	$7,203	($4,167)
		======	======	======	=====	======	======	======	======

OPERATING & MAINTENANCE EXPENSE ($000)

ILLUSTRATIVE RATE IMPACTS

Particulars	Target Costs 1998	1999	2000
(1)	(2)	(3)	(4)
Cost Drivers / Escalators			
Average No. of Customers	734,710	750,609	767,317
Growth %	2.10%	2.16%	2.23%
Productivity Improvement Factor (PIF)	2.00%	2.00%	3.00%
Inflation (CPI)	1.00%	1.00%	1.00%
O&M (Gross)			
O&M	$133,784	$135 343	$135,638
BC Hydro Service Agreement	10,550	10 673	10,696
Total	144,334	146,016	146,334
DRIA's			
- DSM / IRP	1,624	1,624	1,624
- Other	-	-	-
	1,624	1,624	1,624
Total Gross O&M	145,958	147,640	147,958
O'H Capitalized	20.00%	20.00%	16.00%
O&M	28,867	29,203	23,413
BC Hydro Senvice Agreement			
DRIA's - DSM / IRP	-	-	-
- Other	-	-	-
Total O'H Capitalized	28,867	29,203	23,413
Total Per 1998 - 2002 Vol. 1, Page 09-02 (Rev)	15,075	15,510	15,967
Difference	13,792	13,693	7,446
O&M Expense (Net)			
O&M	115,467	116,813	122,921
DRIA's - DSM/IRP	1,624	1,624	1,624
- Other	-	-	-
Total O&M Expense	$117,091	$118,437	$124,545
Total per 1998-2002 Vol.1, Page 09-02 (Rev.)	$133,335	$137,133	$141,126
Difference	($16,244)	($18,696)	($16,581)

Appendix B

Commission Staff letter of July 15, 1997

BRITISH COLUMBIA UTILITIES COMMISSION

WILLIAM J. GRANT
EXECUTIVE DIRECTOR,
REGULATORY AFFAIRS & PLANNING

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
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VIA FACSIMILE

July 15, 1997

Mr. Jim Quail
The British Columbia Public
Interest Advocacy Centre
815 - 815 West Hastings Street
Vancouver, B.C.
V6C 1B4

Dear Jim:

Re: BC Gas Utility Ltd.
Revenue Requirements Application

Thank you for your two letters of July 10, 1997 indicating your consent to the terms of the proposed settlement document along with the letter recording your interpretation of two of the provisions of the proposed settlement of this matter.

With respect to O&M productivity gains from capital projects the settlement document records the method for recognizing productivity at page 5. During our discussions of this matter we explored several examples including the Southern Crossing Project and the construction of a new operations building in the Lower Mainland.

In the case of the Southern Crossing Project the approval and construction of the pipeline would come into rate base the year following its completion. A number of impacts would be felt including funding of the rate base addition, changes to Westcoast or other upstream transportation suppliers, new gas supply options at hopefully more efficient prices, and the potential of third party revenues from the use of spare capacity in the pipeline. None of these components would affect the O&M productivity levels unless BC Gas were also able to obtain a direct O&M productivity improvement from the existence of this new capital edition. If that were to occur it would be available to assist BC Gas in meeting its O&M productivity targets during the remaining term of the three year agreement.

The completion of a new operations centre in the Lower Mainland is probably a better example of where some real O&M productivity might occur. In this case, BC Gas may seek approval and then build the new operations centre allowing it to sell parts of the Boundary/Lougheed property and relocate personnel from a number of leased premises. Presumably, there would also be some down sizing of space requirements at the downtown office. The effect would be that the new capital costs would flow into rate base the year following their completion and the proceeds of the sale of the Boundary/Lougheed property would reduce rate base. These changes would not affect the O&M productivity levels but the Company will likely obtain a number of efficiencies resulting from the more efficient housing of employees, the avoidance of travel, and such matters as the updating of equipment. These benefits are all available to assist the Company in meeting its O&M productivity targets for whatever remaining period exists in the three year settlement.

. . ./2

A third potentially significant CPCN could be the completion of a new customer information system allowing consolidated billing and other links to the financial and work order systems within BC Gas. As with the other projects the capital costs related to the new system would come into rate base in the year following completion. At the same time the Unisys system would be retired from rate base and the billing contract with B.C. Hydro would be terminated. These changes would not effect the O&M productivity targets, but the existence of the new customer information systems would likely have a profound impact on BC Gas operations, allowing improved information and efficiencies in numerous O&M areas of the Company. All of these O&M benefits would assist the Company in meeting the O&M targets for the remaining period of the three year settlement.

I hope this assists by providing an assessment of three of the more significant capital projects which may come to realization late in the three year settlement horizon.

Yours truly,

Original signed by:

W.J. Grant

WJG/lm
cc: Mr. D.M. Masuhara, Vice President
Legal and Regulatory Affairs
BC Gas Utility Ltd.
Mr. David Bursey, Bull, Housser & Tupper
Mr. Chris Weafer, Owen Bird
Ms. Carol Reardon, Heenan Blaikie
Mr. Dave Newlands, Fording Coal,
c/o Pacific Western Energy Products and Services Inc
Mr. R. O'Callaghan, RT O'Callaghan & Associates Inc

Attachment 17.1

C7-4A

BC HYDRO
2007 RATE DESIGN EXHIBIT C7-4a

BC Hydro 2007 Rate Design Application

INTERVENOR EVIDENCE

Evidence of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.

(Revised July 12, 2007)
June 11, 2007

INTERVENOR EVIDENCE

Evidence of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (the "Terasen Utilities" or the "Companies")

The Terasen Utilities are registered intervenors in the BC Hydro 2007 Rate Design Application (BCUC Project No. 3698455). This filing sets out the evidence of the Terasen Utilities in this proceeding. The evidence is in two parts. The first section is the policy evidence of the Companies. The second is a report prepared by EES Consulting.

1. Terasen Utilities Background

The Terasen Utilities collectively serve over 905,000 customers throughout British Columbia, representing more than 95% of the gas utility customers in the province. The Terasen Utilities deliver more energy in total to energy consumers in the province than BC Hydro. In 2006 the Terasen Utilities delivered a combined total of 210 petajoules of energy to gas customers in British Columbia. BC Hydro's F2006 Domestic Electricity Sales of 52,440 GWh by comparison correspond to 189 petajoules. More than 90% of natural gas consumed by the Terasen Utilities customers comes from British Columbia production sources. In addition, more than 60% of the overall natural gas production in British Columbia is exported to the east or south to the Pacific Northwest. Natural gas royalties and provincial revenues from the sale of oil and gas land rights make a large contribution to the provincial budget each year.

2. Energy Landscape in British Columbia

The energy landscape in British Columbia has changed dramatically since BC Hydro's last rate design application in 1991. Market prices for electricity, gas and other fuels are much higher than they were at that time. The energy supply and demand balance is much tighter in North

America than it was in the early 1990s, when both natural gas and electricity were in a situation of significant supply surpluses within the province and regional markets at that time. This is no longer the case. For electricity in particular, BC Hydro's evidence in the 2006 IEP/LTAP proceeding was that a growing gap between electricity demand and supply was forecast to occur over the next twenty years. Filling the gap will require new sources of supply along with demand reductions through energy conservation, efficiency initiatives, load displacement and load avoidance.

In recent years in many parts of North America there has been an increased reliance on the use of natural gas fired electric generation. Concurrently, the North American electric grid has become increasingly sophisticated and interconnected, creating a heavily integrated and interdependent market. Due to the efficiency of this grid, regardless of the region an electric utility is located in, the marginal source of electricity supply is likely to be gas fired, and in almost all circumstances be fossil fuel based generation.

From the perspective of the energy consumer more alternatives are available in 2007 to meet consumer energy requirements than in the early 1990s. Alternative energy sources such as geothermal, solar thermal, waste heat recovery, and fuel cells are becoming more widely adopted and more economically feasible than at any time in the past. Rising energy costs for the traditional sources of energy (electricity, natural gas and other fossil fuels) have made alternative energy sources comparatively less expensive, particularly when used in direct applications. In the same time period there have been improvements and advances in alternative energy technologies. Alternative energy technologies are being promoted by government policies and incentive programs in order to achieve environmental benefits, supply diversification and energy sustainability. Public concern about the environment and climate change on a local and global basis has also spurred interest in alternative energy technologies and has influenced government policy, such as those related to greenhouse gas emissions ("GHG") and particulates.

The majority of these issues were addressed in The BC Energy Plan, which was released February 27, 2007(the "BC 2007 Energy Plan").

3. The BC 2007 Energy Plan

Commissioner Pullman, the chair of the Commission hearing panel identified the BC 2007 Energy Plan as the "policy context" of the 2007 BC Hydro Rate Design Application (Transcript, Volume 1, p.7). The Terasen Utilities agree with this characterization.

The BC 2007 Energy Plan, released February 27, 2007, contains a large number of policy action items as well as policy statements that relate to utilities in general, to BC Hydro specifically, and to utility rate design in general.

- Action Item 1 – "Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020."

- Action Item 2 — "Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia."

- Action Item 3 – "Encourage utilities to pursue cost effective and competitive demand side management opportunities."

- Action Item 4 – "Explore with BC utilities new rate structures that encourage energy efficiency and conservation."

- Action Item 10 – "Achieve Electricity Self-Sufficiency by 2016."

- Page 21 – "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar and geothermal. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas".

- Page 15 – "British Columbia must look for new, innovative ways to stay competitive."

- Page 14 - "British Columbians require a secure, reliable supply of competitively priced electricity now and in the future."

In its review of the BC Hydro Rate Design Application and its subsequent recommendations, the Terasen Utilities have paid particular attention to these policy statements, as well as the remainder of the BC 2007 Energy Plan, in addition to generally accepted rate design principles.

4. The Interests of the Terasen Utilities in the BC Hydro Rate Design Application

As major providers of energy and energy services to utility customers in British Columbia the service areas of the Terasen Utilities coincide, with some exceptions, with the service territory of BC Hydro. The products and services provided by the Terasen Utilities are in some ways complementary to the products and services provided by BC Hydro, and in other ways are in competition with the products and services provided by BC Hydro. The Terasen Utilities and BC Hydro are, for example, complementary providers of demand side management and energy conservation and efficiency programs to energy consumers in the province. On the other hand the Terasen Utilities and BC Hydro are competitive providers of energy for space heating, water heating, cooking and clothes drying. Alternative energy technologies such as heat pumps, geoexchange and solar systems are emerging as competitive as well as complementary energy sources to the more traditional energy sources of gas and electric.

The outcomes and Commission determinations from this proceeding with respect to customer rate design, connection and system extension policies will indirectly affect the Terasen Utilities, particularly in areas where consumers have choice between gas and electric forms of energy.

The Terasen Utilities are also regulated by the BCUC and have interests in the regulation of other utilities in the province on several fronts, including:

- Findings by the Commission of a general nature which may affect future decisions with respect to applications by the Terasen Utilities.
- Commission determinations in this proceeding regarding the regulation of electricity that affect the competitive position of gas.
- Commission determinations in this proceeding that pertain to the policy actions and implementation of the BC 2007 Energy Plan.

The Terasen Utilities have interests in the BC Hydro Rate Design Application from the perspective of overall energy costs in the province and the impact of the Commission determinations in this proceeding on the overall energy costs incurred by energy consumers.

5. Refinements to Rate Design

The Terasen Utilities have noted BC Hydro's characterization of its 2007 Rate Design Application as foundational and setting an appropriate base from which various future rate applications will be filed to more explicitly address implementation of the BC 2007 Energy Plan. The Terasen Utilities agree that establishing the correct foundation in this proceeding is a necessary and important objective. For this reason, the Terasen Utilities believe that there are two major shortcomings of BC Hydro's Rate Design Application. First, with this application BC Hydro is missing the opportunity to put rate design constructs in place in a timely fashion that will serve to promote energy efficiency, conservation and load avoidance and promote the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. Specifically, the Terasen Utilities are of the view that avoidance of new additional load related to space and water heating is not adequately addressed in the application, nor is the issue of load shedding of existing inefficient load through encouraging the use of alternative energy forms. Second, the cost allocation methodologies that BC Hydro has proposed are not appropriate, thereby creating what can only be characterized as an inadequate foundation upon which to build future rate designs in order to achieve the objectives of the BC 2007 Energy Plan. The Terasen Utilities are of the view that it is incumbent upon utilities in British Columbia to move quickly, and that bold steps are needed to meet the ambitious targets set out in the BC 2007 Energy Plan. The Terasen Utilities recommend changes to the rate design constructs (i.e. the System Extension Test and the customer connection policies) and changes to the cost allocation methodologies that BC Hydro has proposed in its Rate Design Application.

5.1. Benefits to BC Hydro Customers of Avoided Load

The Terasen Utilities have estimated the potential benefits to BC Hydro's customers of avoiding electric space and water heating between 2008 and 2020. This time period was selected for the analysis to be consistent with the BC 2007 Energy Plan target date for BC Hydro meeting 50% of load growth through energy conservation and efficiency. These analyses have been conducted using data on the record in the Rate Design Application proceeding and other publicly available information. The key assumptions are residential account growth of approximately 1.5% until 2020, 20% of new residential accounts using electricity for space heating and 35% of new residential account using electricity for water heating, and incremental cost of new electricity supply at $88/MWh. The analysis, which is found in Attachment 1, addresses the additional supply requirements that will be required, and the resulting additional costs to customers that will occur if no action is taken to avoid this potential load growth associated with water and space heating.

The potential additional supply requirements resulting from new space and water heating load are significant. By 2020 the potential additional annual load for space heating is approximately 966,000 MWh and 400,000 MWh for water heating. In aggregate, by 2020, the potential additional annual space and water heating load is estimated to be 1,366,000 MWh. Avoiding this load would be a significant step in realizing the ambitious conservation targets of the BC 2007 Energy Plan. Failing to act now to address electric space and water heating load growth it will make it more difficult to meet this challenging objective. Avoiding the space heating load growth will have capacity benefits as well by reducing the growth in peak winter requirements.

Similarly, the additional costs that would need to be recovered from customers if the potential space and water heating load is not avoided is significant. Additional supply costs resulting from failing to avoid additional load related to space heating start at $7 million in the first year and build to $85 million/year by 2020. The additional annual supply costs resulting from increased electricity use for water heating start at $3 million in the first year and builds to $35 million/year by 2020. On an aggregate basis this totals $120 million/year in 2020. On a cumulative basis over the time period 2008 through 2020, the total additional supply costs that would be incurred, and therefore recovered from customers, to serve this potential load would equal $868 million ($614 million for space heating and $254 million for water heating).

The avoidance of electric space and water heating load also supports the objective stated in the BC 2007 Energy Plan to reduce GHG emissions. As stated previously, in North America the marginal source of electricity is likely to be gas-fired generation, which on average operates at an energy efficiency rate of roughly 50 to 55%% based on combined cycle technology. Modern direct gas fired appliances operate at much higher efficiencies. For example, new high efficiency natural gas fired furnaces operate at 95% efficiency and natural gas fired water heaters operate at an efficiency ranging between 60% and 85%. If the additional space and water heating loads are served directly by natural gas instead of through gas fired electricity generation at the margin, the GHG emissions savings would be expected to be in the range of approximately 1,200,000 to 1,500,000 tonnes over the same period (2008-2020).

Additionally it should be noted that, based on current prices, new customers who choose to utilize natural gas as the energy source for the activities of space and water heating would realize lower annual bills than if they elected to use electricity for these activities. For example, in the Lower Mainland region a new customer served by Terasen Gas Inc., based on typical consumption of 110/GJ per year, would pay an average unit rate of $12.49/GJ, which is approximately 80% of the equivalent marginal BC Hydro electric rate, on an efficiency adjusted basis.

Thus, there are substantial benefits for BC Hydro's new and existing customers of avoiding new load in the end uses of space and water heating. The Terasen Utilities are of the view that electricity is not the right fuel for the activity of space and water heating, rather these activities are more efficiently served by utilizing natural gas, alternative energies or a combination thereof. If the objectives of the BC 2007 Energy Plan are to be achieved, it is essential that the BC Hydro Rate Design Application address the issue of avoiding additional space and water load. Delaying the implementation of such changes to future rate design applications will forfeit the present opportunity and make it much more difficult to achieve the aggressive targets established by the BC 2007 Energy Plan.

Regarding the matter of load shedding, with this application, BC Hydro has not provided any analysis of new rate structures and the degree to which new structures could be used to reduce inefficient load and lead to conservation. For example, no analysis has been completed to determine if regional or mileage based rate structures would result in more efficient energy use and lead to conservation. Additionally, BC Hydro has not done any analysis to determine if rate structures such as inverted block rates for low consumption customer classes would lead to conservation.

5.1.1. Rate Design Constructs – System Extension Test and Customer Connection Policies

The rate design constructs that affect the decision making process when selecting the energy source for space and water heating in new developments are the System Extension Test ("SET") and customer connection policies. Extension and connection policies can be used to achieve various objectives such as balancing the interests of existing customers against those of new customers or promoting / discouraging energy use in a particular region or end use application.

Builders and developers are the predominant decision makers in the matter of heating and energy systems in new construction. Extension and connection policies influence the energy decisions of builders and developers long before the ultimate residents move in and begin to pay utility bills. The decisions of builders and developers are driven largely by the relative installation cost of electric space heating as compared to alternatives, including natural gas. The SET and connection policies should be focused, in complementary fashion, on sending appropriate price signals to builders and developers to encourage the most efficient energy source in new dwellings for space and hot water heating.

BC Hydro has proposed some good changes to simplify the SET; however, the system extension fees and the connection charges arising from BC Hydro's proposals in the Rate Design Application will do little to address the winter peak or avoid load growth from space and water heating that would be better served by natural gas, alternative energies, or a combination thereof, and will fail to contribute to the realization of the objectives of the BC 2007 Energy Plan. The Terasen Utilities propose changes to the SET and the customer connection policies, which are aimed at avoiding electric load growth related to space and water heating and will be aimed at reducing the growth in the system winter peak.

The BCUC in its System Extension Guidelines recommends that a Discounted Cash Flow ("DCF") methodology is used to evaluate system extensions. In addition, the BCUC Guidelines state, to the extent possible, that the methodology should include all incremental costs and benefits associated with a particular system extension. BC Hydro has proposed changes to its SET, moving away from a DCF methodology to a simplified methodology that attempts to consider only the incremental distribution related costs and revenues. In the EES evidence, several SET methodologies are reviewed and summarized in Table 5, and the evidence shows that among those methodologies reviewed by EES, BC Hydro's proposed methodology results in the *highest* credit, or allowance per customer and the lowest contribution made by builders and developers. The Terasen Utilities believe that this is not the appropriate price signal to developers faced with a choice between gas and electricity for space and water heating. As described in the EES evidence, the BC Hydro proposal is not appropriate, and the Terasen Utilities recommend the approach set out in the EES evidence be adopted by the Commission. The recommended SET approach considers the incremental distribution costs and results in an allowance or credit of $1,300 per residential customer (as opposed to $1,900 per residential customer under the BC Hydro proposal), which will require larger contributions on the part of a developer or builder to install electric space or water heating .

However, as neither the BC Hydro nor EES approach to the SET considers the incremental cost of supply to serve the space and water heating load, the Terasen Utilities believe that the customer connection policies that have been proposed by BC Hydro are inadequate. As stated above, customer connection policies should be considered in a complementary fashion with the SET, and with the aim of achieving goals of the BC 2007 Energy Plan. The Terasen Utilities are of the view that there should be a significant differentiation between the connection charge for new customers with electric space heating as compared to those new customers without electric space heating. Although it may not be the case in all instances, it is generally ~~possible to identify~~the case that customers (primarily developers and builders) who intend to install electric space heating ~~because a residential customer with electric space heating~~ will typically require a 200 Amp or greater service~~,~~ whereas ~~a~~ customers without electric space heating will typically require a 100 Amp service. The connection charge proposed by BC Hydro for a 200 Amp service connection is only $33 more than the charge for a 100 Amp service (Exhibit B-1, Table 8, p. 60) so there is little or nothing in the connection charge differential to discourage electric space heating. ~~.~~

It is clear that BC Hydro's proposed customer connection charges, coupled with its proposed SET will do little to influence the energy choices for space and water heating that are being made by builders and developers on behalf of energy consumers. They also do not recognize the true cost of electric space heating for new customers. The Terasen Utilities propose that the charge to connection ~~charge for a 200 amp or greater service include~~new customer intending to use electric space heating include a $2,000 surcharge ~~in addition to~~over and above the ~~higher~~

~~direct cost of $33 difference~~service connection charges proposed by BC Hydro. The $2,000 incremental charge represents a small portion of the incremental electricity supply costs associated with the new space or water heating load. The $2,000 surcharge would not be applicable in the event that electricity is to be used for water heating purposes only. This can be demonstrated from a twenty-year present value calculation of the $57/MWh difference between new supply costs and the embedded costs of electricity times the avoided load per customer for electric space or water heating (14,748 kWh/year and 3,487 kWh/year respectively). On this basis, for each avoided electric space heating customer BC Hydro's other customers will save approximately $9,600 on a present value basis. For avoided electric water heating the comparable present value savings for BC Hydro's other customers would be about $2,300 per new customer. The Terasen Utilities believe that this additional charge, which is only a small portion of the avoided incremental supply costs, will be a material price signal to builders and developers and will result in the avoidance of new additional electric space and water heating load.

A key issue in regard to BC Hydro's proposed SET and connection policy is the treatment of the Heritage Resources. BC Hydro takes the position that the low cost Heritage Resources should be as much to the benefit of future customers as they are to the current customers of BC Hydro. BC Hydro is of the view that new customers should not pay for the marginal cost of new electricity supply in their rates or through extension / connection charges since that would deprive them of a suitable share of the Heritage Resource benefits. This argument is set out in lines 17 to 26 of page 56 of the Rate Design Application and discussed further in response to information requests (e.g., Exhibit B-3, BCUC IR 1.45.1 and 1.45.3). It is the Terasen Utilities understanding that BC Hydro's view comes from its interpretation of the 2002 Energy Plan policy actions dealing with the Heritage Resources as well as the BC 2007 Energy Plan. The rate design constructs that the Terasen Utilities have recommended do not deprive new customers of a suitable share of the Heritage Resources but rather work to ensure such a valuable resource is conserved for the best uses. In fact, the recommendations of the Terasen Utilities, by encouraging the use of the "right fuel, for the right activity at the right time" (to quote the BC 2007 Energy Plan), will help to preserve a larger proportionate share of the Heritage Resources for the activities for which electricity is the right fuel, for existing customers as well as new customers. The Heritage Resources will continue to be a larger portion of the overall supply portfolio if this additional load is avoided, than it would otherwise have been.

5.2. Cost Allocation Methodologies

The specific characteristics of the system must be taken into consideration in the determination of the appropriate cost allocation methodologies to be used in the utility's Cost of Service Study ("COS"). As set out in the EES evidence, the cost allocation methodologies proposed by BC Hydro in its Rate Design Application related to the allocation of generation and transmission demand related costs as well as the classification of distribution costs, are not appropriate.

5.2.1. Generation and Transmission Demand Allocator

The evidence filed in this proceeding demonstrates that the BC Hydro system is a winter-peaking system. Residential electric space and water heating contributes materially to the winter peak, and will continue to do so. Nevertheless BC Hydro proposes to allocate generation and transmission demand-related costs to the customer classes using a 12 coincident peak (CP) allocator, which according to EES is typically employed where there is no pronounced winter peak. The Terasen Utilities are of the view that a winter peak demand allocator (EES recommends 3 CP) would result in a more appropriate allocation of transmission and generation costs to customer classes and would be better reflective of the nature of the BC Hydro system and consistent with the cost-causation principle.

5.2.2. Demand – Customer Split of Distribution Costs

In its application BC Hydro did not provide any rigorous analysis of the cost causal nature of its distribution system to be used to classify distribution costs, rather it based its classification on "experience and the practices of other distribution utilities" (Exhibit B-3, Terasen IR 1.14.4). As this Rate Design Application and the inherent cost allocations form the foundation for future rate design initiatives, it is important that this foundation be based on generally accepted rate design principles, including cost-causation. The Terasen Utilities support the conclusion reached in the EES evidence with respect to distribution related costs that BC Hydro should be required to prepare a rigorous study, but in the absence of a study a demand/customer classification of 50%/50% be adopted. The Terasen Utilities believes this to be a truer reflection of the costs and should be addressed in rates.

5.2.3. Rate Rebalancing

Employing the more appropriate cost allocation methodologies described in section 5.2.1 and 5.2.2 would result in R:C ratios for the customer classes, as included in the EES evidence, move further away from unity (i.e. 1.0) based on current rates. Consequently, the rate rebalancing proposals that BC Hydro included in its Rate Design Application should be reconsidered in order to move the R:C ratios closer to unity.

6. Summary

The Terasen Utilities are of the opinion that the BC Hydro Rate Design Application could do significantly more to promote achievement of the objectives included in the BC 2007 Energy Plan. In particular, there are no initiatives or rate structures proposed that would result in the avoidance of additional electric load, specifically, that load related to new space and water heating. Electricity is not the "right fuel" for space and water heating. The avoidance of this additional load will allow for significant progress to be made towards achieving the ambitious conservation target as well as reduce overall supply related costs to all customers of BC Hydro. The Terasen Utilities believe that this matter needs to be addressed within this proceeding and makes recommendations related to the SET and connection policies toward that end.

The Terasen Utilities are of the view that the cost allocation methodologies proposed by BC Hydro in its Rate Design Application for the allocation of generation and transmission demand-related costs as well as that used to classify distribution costs are not inappropriate and will not provide the appropriate foundation for future rate design initiatives. The Terasen Utilities have recommended changes to these allocation methodologies, which better reflect the winter-peaking nature of the BC Hydro system and are more consistent with the cost-causation principle. If adopted, these changes will provide for a more appropriate foundation for future rate design initiatives. The results of employing the cost methodologies advocated by the Terasen Utilities for the generation and transmission demand allocator and the distribution cost classification will cause the R:C ratios for customer classes to move further away from unity. Therefore, the rate rebalancing proposals should be revised such that the R:C ratios for the customer classes move closer to unity.

C7-17

BC HYDRO
2007 RATE DESIGN EXHIBIT C7-17

Attachment 1 (Revised July 18, 2007)
Terasen Utilities Evdience in BC Hydro Rate Design
Calculation of Potential Benefit of Avoided Electric Space & Water Heating

Space Heating

	Forecast Residential Growth Rate	Residential Accounts	Residential Account Growth per Exhibit B-66	New Residential Space Heating Accounts per Exhibit B-66	Cumulative New Residential Space Heating Accounts	Average Annual Electric Space Heating Load per Exhibit B-66 (kWh/customer/year)	New Electric Space Heating Load (MWh)	Incremental Annual Supply Cost from New Space Heating @ $88 per MWh ($ millions)	Cumulative Potential Avoided Electricity Supply Costs from New Space Heating ($ millions)	Space Heating Costs Recovered from Others (i.e. Marginal Cost less Embedded Cost) ($88/MWh - $31/MWh) $57 ($ millions)	Cumulative Incremental Space Heating Costs Recovered from Others ($ millions)
2007/08	1.8%	1,543,990	27,793	5,560	5,560	14,116	78,485	6.91	6.91	4.47	4.47
2008/09	1.8%	1,571,316	27,326	5,476	11,036	14,136	156,005	13.73	20.64	8.89	13.37
2009/10	1.7%	1,598,401	27,085	5,433	16,469	14,164	233,267	20.53	41.16	13.30	26.66
2010/11	1.7%	1,624,659	26,258	5,276	21,745	13,965	303,669	26.72	67.89	17.31	43.97
2011/12	1.6%	1,650,367	25,708	5,175	26,920	13,946	375,426	33.04	100.92	21.40	65.37
2012/13	1.5%	1,675,046	24,679	4,980	31,900	13,904	443,538	39.03	139.95	25.28	90.65
2013/14	1.5%	1,699,285	24,239	4,898	36,798	13,869	510,351	44.91	184.87	29.09	119.74
2014/15	1.4%	1,723,524	24,239	4,904	41,702	13,842	577,239	50.80	235.66	32.90	152.64
2015/16	1.4%	1,747,763	24,239	4,910	46,612	13,814	643,898	56.66	292.33	36.70	189.35
2016/17	1.4%	1,772,002	24,239	4,910	51,522	13,814	711,725	62.63	354.96	40.57	229.92
2017/18	1.3%	1,796,241	24,239	4,910	56,432	13,814	779,552	68.60	423.56	44.43	274.35
2018/19	1.3%	1,820,480	24,239	4,910	61,342	13,814	847,378	74.57	498.13	48.30	322.65
2019/20	1.3%	1,844,719	24,239	4,910	66,252	13,814	915,205	80.54	578.66	52.17	374.82
Total			**328,522**	**66,252**				**$578.66**		**$374.82**	

Water Heating

	Forecast Residential Growth Rate	Residential Accounts	Residential Account Growth per Exhibit B-66	New Residential Water Heating Accounts per Exhibit B-66	Cumulative New Residential Water Heating Accounts	Average Annual Electric Water Heating Load per Exhibit B-66 (kWh/customer/year)	New Electric Water Heating Load (MWh)	Incremental Annual Supply Cost from New Water Heating @ $88 per MWh ($ millions)	Cumulative Potential Avoided Electricity Supply Costs from New Water Heating ($ millions)	Water Heating Costs Recovered from Others (i.e. Marginal Cost less Embedded Cost) ($88/MWh - $31/MWh) $57 ($ millions)	Cumulative Incremental Water Heating Costs Recovered from Others ($ millions)
2007/08	1.8%	1,543,990	27,793	9,684	9,684	3,164	30,640	2.70	2.70	1.75	1.75
2008/09	1.8%	1,571,316	27,326	9,529	19,213	3,125	60,041	5.28	7.98	3.42	5.17
2009/10	1.7%	1,598,401	27,085	9,453	28,666	3,087	88,492	7.79	15.77	5.04	10.21
2010/11	1.7%	1,624,659	26,258	9,177	37,843	3,083	116,670	10.27	26.03	6.65	16.86
2011/12	1.6%	1,650,367	25,708	8,992	46,835	3,079	144,205	12.69	38.72	8.22	25.08
2012/13	1.5%	1,675,046	24,679	8,639	55,474	3,075	170,583	15.01	53.74	9.72	34.81
2013/14	1.5%	1,699,285	24,239	8,492	63,966	3,072	196,504	17.29	71.03	11.20	46.01
2014/15	1.4%	1,723,524	24,239	8,494	72,460	3,068	222,307	19.56	90.59	12.67	58.68
2015/16	1.4%	1,747,763	24,239	8,495	80,955	3,065	248,127	21.84	112.43	14.14	72.82
2016/17	1.4%	1,772,002	24,239	8,495	89,450	3,065	274,164	24.13	136.55	15.63	88.45
2017/18	1.3%	1,796,241	24,239	8,495	97,945	3,065	300,201	26.42	162.97	17.11	105.56
2018/19	1.3%	1,820,480	24,239	8,495	106,440	3,065	326,239	28.71	191.68	18.60	124.16
2019/20	1.3%	1,844,719	24,239	8,495	114,935	3,065	352,276	31.00	222.68	20.08	144.24
Total			328,522	114,935				**$222.68**		**$144.24**	
Combined Total - Space and Water Heating							**1,267,481**	**$801.34**		**$519.05**	

Notes: 1: New Residential Accounts, Electric Space Heating Accounts, Electric Water Heating Accounts and Use per Account for Electric Space and Water Heating taken from Exhibit B-66
2. For years after F2016 the F2016 values for the above items in Exhibit B-66 have been extended to the end of the analysis period