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August 15, 2008

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Ms. Leigha Worth, Barrister & Solicitor

Dear Ms. Worth:

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 British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") 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 BCOAPO 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-1, Executive Summary, p. E-1

1.1 TGI and TGVI (collectively "Terasen" or the "Companies") propose to charge program expenditures to a regulatory asset deferral account and amortize the balance over 20 years. In the Companies' view, does establishing a regulatory asset deferral account automatically mean that the balances contained therein must attract a cost of equity capital? Please explain.

Response:

Mid-year balance of regulatory deferral accounts are considered part of approved Working Capital, and are accordingly included in Rate Base. Typically, regulatory assets are financed in accordance with approved regulatory structure. In the case of TGI, this is 64.99% debt financing and 35.01% equity financing, and in the case of TGVI is 60% debt financing and 40% equity financing. As such, the cost of capital for regulatory assets such as those proposed in the application would include an equity return component.

2.0 Reference: Exhibit B-1, Executive Summary, p. E-2

The Application states that "TGI's EEC activity in 2007 produced a yield of $2.58 spent/GJ conserved, well below customer gas cost rates including midstream cost that averaged $8.33 Cdn/GJ for residential lower mainland customer in 2007."

2.1 In Companies' view, does this imply that expenditures per GJ above $8.33 in 2007 on any initiative would have been uneconomic and not in the public interest?

Response:

As described in Section 6.13 of Exhibit B-1, the Application, the Companies' view is that the appropriate approach to cost-benefit analysis is a portfolio approach, where the overall TRC for the entire portfolio of EEC activities being proposed by the Companies must stay at 1.0 or above, and that this approach will provide a portfolio of EEC activity that is in the public interest. The cost of gas is one of the inputs to the TRC test.

3.0 Reference: Exhibit B-1, Executive Summary, p. E-5 and B-1 p. 27

The Application states that "[t]he expenditures set out in Tables 1 and 2 do not include contributions from partners for joint programs where there are electrical savings, which total about $5.5 million over the three year time period."

3.1 Does this mean that if the partners do not contribute to the joint programs as expected that ratepayers will be liable for making up any shortfall?

Response:

No, please see page 56 of Exhibit B-1, the Application, excerpted below:

> *"If partner funding was not available for electrical savings, the natural gas initiatives for the Commercial sector would proceed, but on the basis of providing incentives for natural gas savings alone, rather than combining incentives for natural gas and electrical savings."*

4.0 Reference: Exhibit B-1, Executive Summary, p. E-7, Evaluation Methodology

4.1 Does the reference to achieving economies of scale for technologies that have a TRC < 1.0 by encouraging market penetration refer to economies of scale in the production process of such technologies or does it refer to something else? Please provide examples.

Response:

Please see page 83 of Exhibit B-1, the Application, for an expanded discussion of this matter. The reference is to economies of scale not only in production, but also in supply and installation of efficient technologies. The view of the Companies, as expressed in the response to BCUC IR 1.33.1, is that the Companies have a role to play in supporting commercialization of efficient technologies. This would include production, supply and installation. One example might be in solar thermal water pre-heating, where technology costs are estimated at $8,000 per home, partially due to a lack of trained installers. A pilot program to encourage solar thermal water pre-heating would presumably include a training component, which should increase the number of trained installers and bring installed costs down. Please note that the Companies do not have adequate data to perform a TRC test on this new technology and the nature of any program around this technology would be a pilot program intended to provide the Companies with the data needed to evaluate the cost-effectiveness of this technology. None of the Energy Efficiency or Fuel Switching measures proposed in the Application has a TRC of less than 1.0.

5.0 Reference: Exhibit B-1, Executive Summary, Free Riders, p. E-8
Exhibit B-1, Section 6.13, p. 85
Exhibit B-2, BCUC IR 3.1

The response to BCUC IR 3.1 states that "[t]he Companies believe that free rider rates are notional because of their subjectivity, and that using them in objective analysis such as the DSM cost-benefit tests along with the other "hard" inputs to the tests, which are more easily quantified diminishes the value of those tests."

5.1.1 Does the use of the term "notional" indicate that the Companies believe that free riders may not exist?

Response:

It is the Companies' view that whatever free rider rates might be, they would vary by measure and program. The use of the term "notional" is intended to convey that free rider rates are very challenging to pin down with any certainty.

5.1.2 Do the Companies believe that estimation of free rider rates is more difficult to quantify than say estimates of an appropriate ROE for a given utility through the use of discounted cash flow or comparable earnings tests or any more subjective than these tests?

Response:

The determination of an appropriate ROE for a given utility is based on multiple inputs, but is a necessary determination capable of being made by the Commission based on evidence. None the less the assumptions and comparator groups used are often the subject of significant debate amongst intervenors to the ROE proceedings. The Companies' view is that estimations of free rider rates are subjective and notional, and as such, the topic of great debate within DSM circles. The Companies' position is that since the Companies are not proposing an incentive that is dependent on TRC, which is in turn dependent on free rider rates, that the free rider effect should not be included in the cost-benefit calculations for the activity proposed within this EEC Application.

5.1.3 Do the Companies agree that with respect to low-income DSM programs there is little or no free rider issue?

Response:

The Companies will rely on the advice of the Energy Efficiency for Affordable Housing Working Group (EEAHG) as to free rider rates for low-income DSM programs, however the prevailing view of the DSM industry seems to be that there are little or no free riders on low-income DSM programs.

6.0 Reference: Exhibit B-2, BCUC IR 3.1, p. 6

The Companies state that in their view, "it is the energy consumption reduction outcome that matters, not the way in which it was achieved."

Given this statement,

6.1.1 Is it fair to say that the Application has spending targets, not outcome targets?

Response:

No, it is not fair to say that the Application has spending targets, not outcome targets. Targets for energy reduction outcomes are detailed in Section 7.1.1 of Exhibit B-1, the Application, and as can be viewed in the response to BCUC IR 1.56.2, targets for individual measures are tied to specific spending levels. Further, as outlined in section 6.13 of Exhibit B-1, the Companies have identified an overall portfolio TRC target of 1.0. If the funds don't get approved or spent, the energy savings outcomes will not be achieved, and the proposed expenditures will not be recovered from customers. It should be noted that the Companies intend to submit future requests for EEC expenditures in future years, as outlined on page 50 of Exhibit B-1. Presumably if the Companies are not successful in achieving the energy savings outcomes outlined in this Application that result from the expenditure requested, future EEC Applications will not be successful. Therefore the Companies' view is that there is a strong driver for them to achieve the energy savings detailed in Exhibit B-1.

6.1.2 If outcomes matter, why is cost recovery independent of outcomes?

Response:

It is the view of the Companies' that cost recovery is not independent of outcomes. In the EEC Application, the Companies are proposing that the incremental EEC expenditures be recovered through customer rates, treating the incremental EEC expenditure as capital and amortized over a 20 year period. The 20 year amortization period for cost recovery was selected in order to match cost recovery to the period over which the energy saving outcome are expected to occur. The energy savings outcomes resulting from the EEC activities in the Application are inextricably linked to EEC expenditures – if the funds are not spent and programs are not put in place, the energy savings will not materialize. Thus outcomes (energy savings) are linked with expenditures, which in turn are linked to the cost recovery through rates as outlined in the Application.

6.1.3 In evaluating any project, is it not of critical importance to define the costs of the project and the outcomes specifically attributable to the project?

Response:

Yes, it is important to define costs and outcomes for a project. The costs being proposed in this Application are detailed in Exhibit B-1, as are the energy savings outcomes, all of which result in a portfolio level TRC of greater than 1.0 for the EEC activity outlined in the Application.

7.0 Reference: Exhibit B-1, Executive Summary, p. E-9

The Companies propose to include EEC associated deferral account balances in rate base on an after tax basis.

7.1.1 Please confirm that under this method, ratepayers will be responsible for associated income taxes as well as return on capital.

Response:

Yes, ratepayers are responsible for related income taxes under the proposed financial treatment set out in the Application. However, by including EEC associated deferral account balances in rate base on an after tax basis, ratepayers receive the benefit of the tax deductions immediately, which reduces the annual cost of service and customer rates. As it relates to return on capital, the Companies have proposed a methodology that is consistent with Utilities Commission Act Section 60(b)(ii), which provides utility to have rates that allow for a fair and reasonable return on EEC related expenditures.

7.1.2 Please provide the assumptions under which the Companies' rate base treatment proposal of the EEC expenditures is "least cost" for ratepayers.

Response:

"Least cost" for ratepayers is represented by the lowest NPV of Cost of Service. The Companies have considered various financial assumptions during the preparation of the Application. The Companies considered whether costs, in whole or in part, should be capitalized by way of a regulatory asset deferral versus expensing the expenditures. Also, the Companies considered the question of the appropriate amortization period. Additionally, the Companies considered whether EEC expenditures should be included in the regulatory asset deferral account on an after-tax basis or on a before tax basis.

The Companies have proposed in the Application that the EEC expenditures be capitalized by way of a regulatory asset deferral account on an after-tax basis and amortized over a 20 year period, matching the benefits received by customers. The Companies' elected the after-tax treatment as it results in a lower cost of service and is consistent with the financial treatment approved for other rate base deferral accounts. These assumptions result in the lowest NPV of Cost of Service.

Please refer to the response to BCUC IR 1.10.2 for a discussion of the Companies' rationale for its proposed financial treatment.

7.1.3 Please indicate what other treatments the Companies considered for these expenditures prior to filing this Application.

Response:

Please refer to the response to BCUC IR 2.7.1.2.

7.1.4 Please indicate the Companies' view as to the discount rate that a typical residential household would use in determining its optimal intertemporal expenditure plan.

Response:

There is a considerable body of research into consumer behaviour that suggests that the implicit discount rates used by residential customers in making decisions about investments in energy efficiency are much higher than typical utility costs of capital. These studies recognize that there is a wide spectrum of decision-making approaches taken by consumers in assessing energy efficiency investments ranging from no analysis at all to the use of simple payback measures to more sophisticated approaches recognizing the time-value-of-money. While there are likely numerous reasons and contributing factors a general observation from these studies is that residential consumers look for short payback periods for energy efficiency investments and therefore that the implied internal rate of return for these investments is quite high – often in excess of 20%. Another aspect noted is that consumers appear to apply higher hurdle rates to energy efficiency investments than to other types of household investments.

The Companies do not have a specific view as to the selection of single value for the discount rate of a typical residential household but consider it reasonable to expect that it would be higher than the after-tax cost of capital of the Companies.

Please see also the response to BCUC IR 2.8.1.

8.0 Reference: Exhibit B-1, Section 1.2, p. 2

8.1 With respect to the incentive funds authorized by Order No. G-85-97 that were placed in a deferral account and amortized over three years, are there any differences between that treatment and the Companies' current proposals for EEC expenditures other than (i) the inclusion of non-incentive expenses and (ii) amortization period?

Response:

No, there are no other (inclusion of non-incentive expenses and different amortization period) differences between the current proposal and the financial treatment authorized by Order No. G-85-97 (see response to BCSEA SCBC IR 1.14.1, Attachment 14.1).

9.0 Reference: Exhibit B-2, BCUC IR 5.2

9.1 Please confirm that as long as demand is not perfectly inelastic (and the good is not a Giffen good) that higher prices are associated with lower levels of quantity demanded, other things equal.

<u>Response:</u>

It is confirmed that so long as demand is not perfectly inelastic (and the good is not a Giffen good) that higher prices are associated with lower levels of quantity demanded, other things equal.

10.0 Reference: Exhibit B-1, Section 1.4.1, p. 9, Table 1.4.1a

10.1 Please confirm that under the Companies' proposed rate base treatment of expenditures, the entire $56.611M will be allocated among rate classes as rate base (and equity return) is currently allocated, irrespective of which classes receive direct benefits from the spending. If unable to so confirm, please explain.

Response:

The incremental EEC expenditures will be charged to a regulatory asset deferral account on an after-tax basis and therefore included in rate base. The cost of service related to the rate base, including the amortizations and earned return, will be recovered from all customers irrespective of the receipt of direct benefits.

11.0 Reference: Exhibit B-1, Section 1.4, p.9, Exhibit B-1, Section 3.5

Section 1.4 states:

The Companies are seeking Commission approval for the overall incremental expenditures in Table 1.4.1 based on the contemplated program areas and funding summarized in Table 1.4.1a and described in Section 6. This approach preserves the Companies' ability to subsequently redirect funds from one program area to another program area that the Companies conclude is generating more favorable results based on the assessment criteria outlined in this Application.

11.1 What procedure do the Companies propose they will engage in before redirecting funds from one program to another?

Response:

The Companies intend to monitor the relative performance of programs on a monthly basis in order to ensure that the overall portfolio TRC is maintained at 1.0 or higher. If the Companies see the potential to redirect funds from one program area to another, the Companies would bring forward a recommendation to the Stakeholder Group outlined in Section 6.14.2 of Exhibit B-1, as well as detailing any changes in the Annual Report proposed in Section 6.14.1 of Exhibit B-1.

11.2 Do the Companies anticipate assessing each program on the same criteria, or will there be some recognition that certain programs may have a lower cost effectiveness yet still form a valuable element to the overall EEC strategy? How might this recognition, if applicable, effect the redirection of funds?

Response:

If the question above relates specifically to the funding proposed under Joint Initiatives for DSM for Affordable Housing, the Companies are proposing to rely on the advice of the Energy Efficiency for Affordable Housing Group on the appropriate criteria for cost-effectiveness of programs in this sector, as outlined on page 84 of exhibit B-1, the Application.

A discussion of proposed cost-effectiveness tests for all the activities outlined in the Application can be found in Section 6.13 of the Application.

12.0 Reference: Exhibit B-1, Section 2, pp 15-16

12.1 Please indicate how the Companies currently treat utility costs related to advertising and public communications in their non-EEC activities.

Response:

There are two methods for handling communications costs by the utility for non-EEC activities. The first is for recurring activities like rate changes and safety messaging. In this case, these costs are considered part of the utility's operating budget and expensed in the year in which they are incurred. These costs are part of the rate that all customers pay. The second is for customer education relating to the Customer Choice program. In this case the costs are charged to a deferral account that is expensed in the year in which they are incurred and recovered from all customers eligible to participate in the Customer Choice program.

13.0 Reference: Exhibit B-2, BCUC IR 6.1

13.1 Please indicate whether the Companies are aware that both Union Gas and Enbridge have approved Demand Side Management variance Accounts (DSMVA) and that they may only recover more than their approved budgets, up to a cap, if the audited evaluations of their DSM activities show that they have exceeded volume savings targets?

Response:

Yes, the companies are aware of OEB Decision EB-2006-0021 approving negotiated settlements, which provides in part:

"Parties agree that the DSMVA shall be continued. The DSMVA shall be used to "true-up" the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs."

"There should be no limit on the amount of under spending from budget that should be returned to ratepayers. Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility's DSM budget for that year."

"The Board finds the Financial Package proposal to be reasonable. The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%). It will also ensure that unspent DSM funds are returned to ratepayers[1]."

"Further, if audited evaluations of DSM activities show that they have exceeded volume savings targets: "the utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis[2]."

There are some differences and similarities of the Ontario model to the Companies proposal with this Application. Under the proposals in the Application, the Companies are requesting a maximum level of EEC expenditures of $56.6 million. If the Companies wish to increase EEC funding for the period 2008 through 2010, a separate application

[1] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf p.30
[2] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf p.13

requesting Commission approval for additional funding will be required. The Companies believe that this can provide greater protection to customers than the Ontario model. However, similar to the Ontario model, in the event that the Companies are unable to actually disburse the $56.6 million requested in this Application, customers will effectively be reimbursed for the under-spent portion, as the actual costs are debited to the deferral account.

14.0 Reference: Exhibit B-1, Section 2, p. 16
Exhibit B-2, Section 6.14.2, Stakeholder Group

14.1 Please indicate whether the Companies would be prepared to establish an EEC audit subcommittee composed of ratepayer representatives that would review a draft evaluation report prepared by an independent auditor prior to the evaluation being finalized each year.

Response:

The Companies would need to discuss the value of such a report with the proposed Stakeholder Group to obtain their input prior to committing to such a process. Further, the Companies would want some guidance from the Evaluation Working Group of the British Columbia Partnership for Energy Conservation and Efficiency (BCPECE) prior to committing to such a process.

15.0 Reference: Exhibit B-1, Application, page 17, Figure 3.1

15.1 In pre-filing discussions with counsel from BCOAPO et al, Terasen representatives stated that the Companies' main focus in fuel switching was to switch customers from oil to Natural Gas. However, Figure 3.1 shows that only 0.6% of British Columbia's residential energy use is from Heating Oil. Please reconcile this with Terasen's proposed fuel switching budget of approximately $3.7 M.

Response:

Please see the responses to BCSEA SCBC IR 1.18.1 and 18.2.

16.0 Reference: Exhibit B-1, Section 3.2.1, Table 3.2.1

16.1 Please provide the Companies' view as to the best <u>theoretical</u> approach to calculating annual savings attributable to the Destination Conservation program.

<u>Response:</u>

The Companies view is that this should be a function of the number of participants multiplied by estimated energy savings per participant.

17.0 Reference: BCUC IR Response 10.2

17.1 Given this response with respect to capitalizing all DSM O&M costs and their statements in respect of capitalization reducing rate volatility, why don't the Companies propose to capitalize all of their utility O&M spending?

<u>Response:</u>

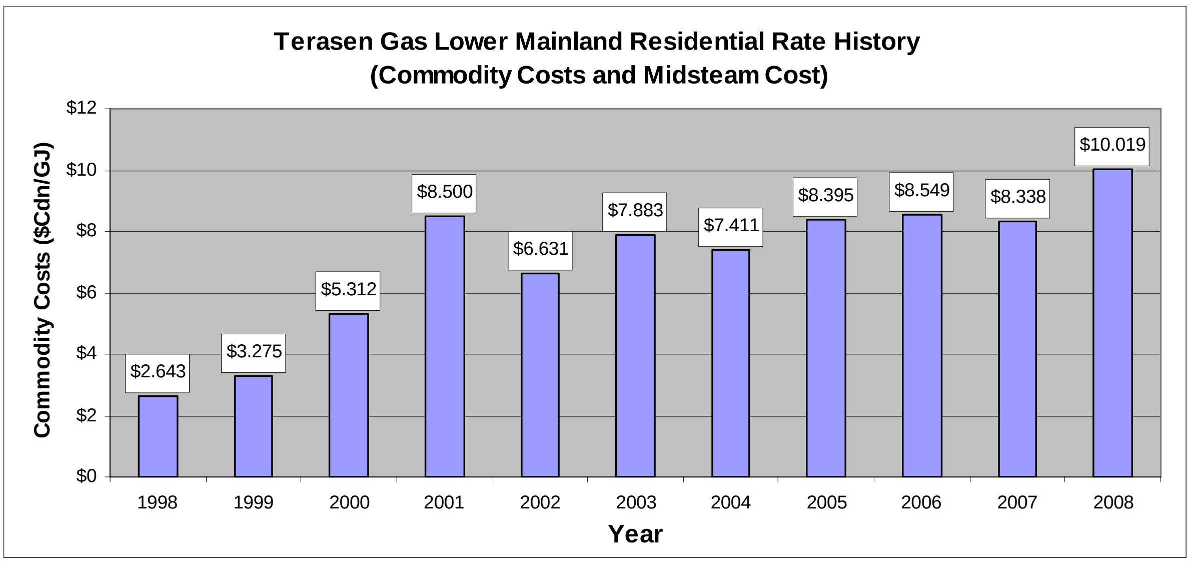
In order to be capitalized, items must meet the definition of an asset. Per CICA Handbook Section 1000.29, "Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained." In order to meet the definition of an asset, there must be a future benefit that involves the capacity to contribute directly or indirectly to future net cash flows. O&M spending is generally undertaken do support the current year's results, and contributes to the current year's cash flows, and therefore does not qualify for capitalization as an asset. As discussed in the response to BCUC IR 1.44.2, the Companies are of the view that EEC expenditures qualify as intangible assets and provide future economic benefits, therefore, it is not unreasonable to place them into a regulatory asset deferral account. The Companies make no such claim for all of the Utility O&M expense.

18.0 Reference: Exhibit B-1, Section 3.3, p. 30, Tables 3.3 and 3.3a

18.1 Please indicate whether the values shown in these tables represent commodity costs only or delivered commodity costs. If they include utility delivery charges, please provide comparable tables that show commodity costs only.

<u>Response:</u>

The values shown in Figures 3.3 and 3.3a are total delivered costs, which include commodity costs and delivery costs. The table below outlines the average commodity cost plus midstream costs that form part of the total delivered cost in Figures 3.3 and 3.3a.



19.0 Reference: Exhibit B-1, Section 3.4, Customer Usage Rates

19.1 Can any inferences be drawn from the shapes of these weather normalized average use graphs in respect of the effectiveness of the Companies' DSM programs from 2004 onwards or do these graphs back out DSM savings volumes?

Response:

The weather normalized average use graphs illustrated in Exhibit B-1, Section 3.4 do include the DSM savings volumes which were a result of the Companies' DSM programs from 2004 onwards. Therefore, it can be inferred those DSM programs contributed to the trends observed in the average use graphs. However, it must be recognized that the consumption savings from the Companies' DSM programs is a small portion of overall residential and commercial demand. And, with other factors such as shifts in housing type, ongoing retrofit activity, the competitiveness of natural gas, and public policy also playing a part in the trends seen in those average use graphs, it becomes very difficult to draw concise inferences with regards to specifically the effectiveness of the Companies' DSM programs.

19.2 Given that to the extent the Companies' EEC proposals are effective, one would expect declines in normalized average use. Have the Companies given any thought as to the implications of this with respect to fixed cost recovery and class rate design?

Response:

Currently when declining use rates cause an increase in unit margin, the basic charge and variable delivery charge are increased by the same proportion. The fixed costs determined from the cost of service studies have historically been under recovered (i.e. the basic charge is less than the allocated fixed costs). TGI does not expect a significant change in the under recovery of its fixed costs resulting from the EEC programs and expenditures.

19.3 Is there any simple explanation known to the Companies for recent increases in normalized average use as shown in Figures 3.4a, 3.4b, and 3.4c?

Response:

There is no simple explanation known to the Companies for the recent increases in normalized average use rate for the TGI Rate 2, TGVI SCS2, or the TGVI RGS customers. For these customers, consumption has been relatively stable over the past seven years, with the year over year variation in normalized average use rate being typical of that seen within each of those rate classes historically.

20.0 Reference: Exhibit B-1, EEC Expenditures at Other Utilities, Section 3.5, Table 3.5 Exhibit B-1, Appendix 4, DSM Activity at Other Utilities

20.1 Please provide a table comparing the total DSM expenditures and low income specific DSM spending for the utilities listed in Table 3.5 and of the Application. Please provide dollar amounts and percentage of overall spending.

Response:

In an effort to respond to this Information Request, the Companies researched the utilities presented in Table 3.5 in the EEC Application. Please refer to the revised table following that includes low-income budgets for most utilities and a calculation of percentage of overall spending. Please note that in most cases these figures were derived from public websites and/or phone discussion with DSM staff. In most cases, utilities do not provide calculations of percentage of overall spending and could not be verified; therefore, these calculations were done by the Terasen Utilities' DSM staff and should be treaded as approximate amounts only.

PG&E and Southern California Gas

Below are the adopted budgets for 2007 and 2008 for four large utilities in California (including PG&E and SoCalGas).

2007 and 2008 Utility LIEE and CARE Adopted Budgets[3]				
	2007		**2008**	
Utility	**CARE[4]**	**LIEE[5]**	**CARE**	**LIEE**
PG&E	$544,557,000	$77,733,500	$595,432,000	$77,733,500
SCE	$256,798,000	$32,609,290	$268,798,000	$32,609,290
SoCalGas	$127,304,243	$33,415,541	$131,003,059	$33,211,971
SDG&E	$48,751,885	$13,424,892	$50,985,233	$13,302,750
Total	$977,411,128	$157,183,223	$1,046,218,292	$156,857,511

Please note that LIEE (Low-Income Energy Efficiency) and budget amounts for California utilities are funded separately from the regular DSM budget[6].

As stated in the Application of Southern California Gas Company (U 904 G) for Approval of Low-Income Assistance Programs and Budgets for Program Years 2009-2011[7], planned budget for 2009-2011 is $163.9 million.

[3] http://docs.cpuc.ca.gov/Published/News_release/62890.htm
[4] CARE stands for California Alternate Rate for Energy.
[5] LIEE stands for Low-Income Energy Efficiency.
[6] Email Correspondence, Bill Miller, Manager, Strategic Regulatory Issues, PG&E, August 2008.

Manitoba Hydro

Centra and its parent company, Manitoba Hydro, did not have any programs in 2006. It reported to the MPUB that it was developing programs under the program title of "Hard to Reach".

As stated in the in the order No 99/07 (Centra Gas Manitoba in 2007/08 and 2008/09 General Rate Application and Other Matters), Centra forecast expenditures of $690,000, $729,000 and $771,000 on low income targeted incentives, for 2007/08, 2008/09 and 2009/10, respectively. Centra forecasted aggregate low-income targeted spending to 2017 of $4.2 million, but advised that the estimate would likely be exceeded in practice, as formal budgeting for the program had not been finalized beyond 2010."[8]

BC Hydro

As per discussion with Margo Longland, Power Smart Residential Marketing, BC Hydro, there was no budget allocation for 2007 for low-income programs. BC Hydro launched a low-income pilot program in 2008. Further, the 2008 Long Term Acquisition Plan, includes estimates for low-income programming for 2009-2028 period.[9]

FortisBC

As per discussion with Keith Veerman, Manager, Energy Efficiency at FortisBC, the utility did not budget for the Low-Income DSM programs in 2007 or 2008. However, FortisBC filed a joint proposal with Terasen Gas in response to LiveSmartBC's Efficiency Incentive Program Low-Income Household Request for Proposals (RFP) in July 2008.

NW Natural

As stated in the EEC application: "the state-wide annual sum raised towards the PPF (Public Purpose Fund) is between $60 and $80 million. Approximately $11 million is collected from NW Natural customers with $9 million funneled to the Energy Trust of Oregon to fund energy efficiency programs. The remaining two million is retained by NW Natural for low-income weatherization programs."[10]

Further, as per ITEM NO. CA9: "The current OLIEE CAP has been in effect since November 2003. NW Natural collected approximately $1.1 million in funds for low-income energy efficiency assistance from its Schedule 301, Public Purposes Funding Surcharge, before the original program was implemented. The total number of households served by the OLIEE CAP since 2003 is 1,071 (287 in 2003-2004; 337 in

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[7] http://www.socalgas.com/regulatory/documents/a-08-05-025/ApplicationAppendicesAttachments.pdf, refer to Attachment A-1 to view the amounts.

[8] http://www.pub.gov.mb.ca/pdf/07centra/099-07.pdf; p.21-22

[9] http://www.bchydro.com/rx_files/info/info57194.pdf, Table 4, Page 8 gives estimates for the period 2009 – 2028 (options A and B over 20 years)

[10] http://www.terasengas.com/documents/submissions/080528_TGI-TGVI%20EEC%20Application_FF.pdf

2004-2005; 253 in 2005-2006, and 194 in 2006-May 2007) requiring a total OLIEE funds expenditure of about $2.1 million. NW Natural has forecast the public purpose charge is currently collecting almost $2 million per year for the OLIEE program. Despite the efforts of the company and the Agencies delivering the OLIEE program to ramp up the number of low-income homes served, approximately $4.8 million of OLIEE funds collected remain unspent.[11]

Union Gas and Enbridge

As per EB-2006-0021 Decision: "parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan."[12]

ATCO Gas

No low-income programs are currently in place.

SaskEnergy

SaskEnergy has an Energy Share Conservation Program in place the utility allocates $100,000 ($500,000 over 5 years, starting in 2005)[13] for low-income programs.

Gaz Metro

Low income natural gas energy efficiency programs are undertaken by the Energy Efficiency Fund (EEF), a joint collaboration between Gaz Metro and social groups. Funding for the EEF comes from Gaz Metro's Performance Incentive Mechanism and therefore can vary from year to year.

"Gaz Métro launched its EEP in 2000 with programs for its entire residential, commercial and industrial clientele. In 2002, a number of Gaz Métro's energy efficiency programs were transferred to the EEF, including those promoting specific measures for low-income families and programs related to building envelopes and new technologies."[14]

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[11] http://www.puc.state.or.us/PUC/meetings/pmemos/2007/082107/ca9.pdf; p.2
[12] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf; p.32
[13] http://www.gov.sk.ca/news-archive/2005/11/08-1030-attachment.pdf; p.6
[14] http://www.aee.gouv.qc.ca/pdf/publications/cibles-triennales-en.pdf; p.3

3.3.4 Joint GEEP and EEF Programs for Low-income Customers

"With a view to increasing efforts made in respect of low-income households while respecting the basic principles of the *GEEP*, at least 13% of the total annual budget of the *GEEP* and the *EEF* allotted to residential customers will be reserved for complete programs adapted to that clientele and developed jointly by the *GEEP* and the *EEF* and reserved exclusively for low-income households and the social and community clientele that help those households. If the amount is not totally allotted to those customers during that year, it may then be allotted to other programs during the following year after an analysis of the reasons for this failure has been performed. *Gaz Métro* will also make additional efforts, in collaboration with local organizations (ACEF, etc.), to target low-income households as best possible."[15]

PSE

During the 2007 budget year[16], PSE spent the following on Low-Income programs.

2007 Low Income Weatherization Budget Summary

Description	2007 Allocated	2007 Spent
Electric Rider	$ 1,300,337.00	$ 1,662,923.00
Gas Tracker	$ 245,834.00	$ 315,051.00
Subtotal	$ 1,546,171.00	**$ 1,977,974.00**
PSE Funds	$ 300,000.00	$ 295,800.00
Electric C&RD	$ 1,208,681.00	$ 196,746.00
Total	$ 3,054,852.00	**$ 2,470,520.00**

15 http://www.corporatif.gazmetro.com/Data/Media/GazMetro%20Performance%20incentive%20mechanism.pdf p.33

16 Email Correspondence, Sandra Sieg; Manager of Low-Income Weatherization Programs, PSE, August 2008

DSM Comparison Table

Company Name	Utility Type	2007 DSM Annual Budget ($ in millions)	Start DSM year	DSM Funding Treatment	Company Earns on DSM [6]	Return on Equity or Incentive Mechanism	Customer Base	F/T DSM Employees	Total Employees	2006 Asset Base ($ in millions)	2006 Total Revenues ($ in millions)	% Spent on DSM of Revenue	DSM Spent per customer	2006 Annual Sales Volume (PJs)	Low Income DSM Budget ($ in millions)	% Spent on LI/Overall DSM Budget
Pacific Gas and Electric Company ("PG&E")	Combined	279.0 [1]	mid-1970's	Public Purpose Fund	Yes	Incentive Mechanism	5,100,000(E) 4,200,000 (NG) [9]	350 [12]	20,000	34,800	12,530	2.23%	$66.43	425.9	77.7 [24]	22%
Manitoba Hydro	Combined	9.0	1989	DSM costs are treated as capital and amortized over a fixed time period.	No	N/A	516,800(E) 259,569 (NG) [10]	50	3,200	11,000	517	1.74%	$34.67	147.6 [20]	0.7	8%
Southern California Gas Company ("SoCal Gas")	Natural Gas	56.6 [2]	mid 1980's	Public Purpose Fund	Yes	Incentive Mechanism	5,600,000	30	3,000	6,360	4,180	1.35%	$10.11	946.0	33.4 [25]	37%
BC Hydro and Power Authority ("BC Hydro")	Electric	52.3 [3]	late-1980's	DSM costs are treated as capital and amortized over a fixed time period.	No	N/A	1,704,671	131	4,200	12,484	4,311	1.21%	$30.68	190.5	N/A	N/A
FortisBC	Electric	2.5	1989	DSM costs are treated as capital and amortized over a fixed time period.	Yes	Both	154,000	8	570	731	208	1.19%	$16.06	11.1	N/A	N/A
Northwest Natural Gas Company ("NW Natural")	Natural Gas	11.0 [4]	1980	Public Purpose Fund	No [7]	N/A	636,000	1	1,211	1,957	1,000	1.10%	$17.30	125.8	2.0	18%
Union Gas	Natural Gas	17.0	1997	DSM costs are recovered through rates.	Yes	Incentive Mechanism	1,300,000	45	2,200	4,600	2,100	0.81%	$13.08	1,303.0 [21]	1.3 [27]	8%
The Terasen Utilities (Based on approved EEC Budget)	Natural Gas	16.8	1991	DSM costs are treated as capital and amortized over a fixed time period.	Yes	Yes	911,935	12 [13]	1,229	2,909	1,655 [18]	1.02%	$18.45	208.0 [22]	1.0 [26]	6%
Enbridge Gas Distribution ("Enbridge")	Natural Gas	22.0	1995	DSM costs are recovered through rates.	Yes	Incentive Mechanism	1,800,000	45	1,961	3,323	3,016	0.73%	$12.22	445.0	1.3 [28]	6%
TGVI	Natural Gas	1.2	2004? [5]	Program costs as O&M; program incentives are amortized over fixed time period	No	N/A	90,738	4 [14]	103	467	172	0.67%	$12.67	28.0	N/A	N/A
Gaz Metro Limited Partnership ("Gaz Metro")	Natural Gas	8.8	1999	as O&M	Yes	Incentive Mechanism	167,000	6 [15]	1,500	2,700	2,000	0.44%	$52.69	271.8	1.1 [29]	13%
The Terasen Utilities	Natural Gas	4.3	1991	Program costs as O&M; program incentives are amortized over fixed time period.	No	N/A	911,935	4	1,229 [17]	2,909	1,655 [19]	0.26%	$4.69	208.0 [23]	N/A	N/A
TGI	Natural Gas	3.1	1991	Program costs as O&M; program incentives are amortized over fixed time period.	No	N/A	821,197	4 [16]	1,107	2,442	1,483	0.21%	$3.80	180.0	N/A	N/A
Puget Sound Energy ("PSE")	Combined	6.1	early-1980's	DSM costs are recovered via a rider on customer bill.	Yes	Incentive Mechanism [8]	1,000,000(E) 718,000 (NG) [11]	80	2,400	7,061	2,905	0.21%	$8.52	205.1	0.3 [30]	5%
SaskEnergy	Natural Gas	1.6	2001	as O&M	No	N/A	325,000	4	1,000	1,322	1,254	0.13%	$4.92	125.0	0.1	6%
ACTO Gas	Natural Gas	Part of marketing budget	2001	as O&M	No	N/A	969,200	8 - 12	1,700	7,698	2,890	N/A	N/A	219.0	N/A	N/A

Comments:

[1] This figure reflects the 2007 DSM budget for electrical and gas initiatives. This covers labor, rebates and advertising. An additional $24 million will be spent on research and evaluation. On average, 86 per cent of funds are related to the electric side.

[2] This figure reflects the 2007 DSM budget which covers labor, rebates and advertising. An additional $4.3 million will be spent on research and evaluation.

[3] This figure is comprised of the following components: $4.9 million (operating costs) and $47.3 million in deferred capital - note that it is an actual figure rather than a budget figure.

[4] This figure is the sum of $9 million that is dedicated for DSM and market transformation programs implemented through the Energy Trust of Oregon (ETO) and $2 million for low income weatherization administration by NW Natural.

[5] Historically, DSM activity on TGVI has not been well-defined or well-reported upon as the activity for TGI. 2004 is shown as a start year as per BCUC's Order No. C-02-05 mentioned in the Application on p.26.

[6] The utility either earns a return on equity, on a financial incentive or on penalty that is based on DSM Mechanism.

[7] There is a separate line on customers' bill; DSM costs are treated as flowthrough costs.

[8] PSE has an incentive and penalty mechanism for electric programs.

[9, 10 &11] As per IR 16.3.1, these cells show both electric (E) and natural gas (NG) customers for combined utilities; DSM Spent Per Customer is based on NG customers only.

[12] This figure reflects the total number of DSM staff at PG&E, approximately 80% of them spend their time on electric DSM programs.

[13] Proposed combined (TGI and TGVI) staffing requirements as per EEC Application p.79

[14&16] Currently Terasen Gas has a core Energy Efficiency & Marketing staff of four; their time is split between TGI &TGVI.

[15] Overall, over 200 employees, contractors, business partners involved in the delivery of DSM programs at Gaz Métro.

[17] This count includes all FTR employees, both active and inactive, as well as dependent contractors at TGI, TGVI and Terasen Inc. It doesn't balance to the original number of 1237, reported as of Sept 30, 3007, because of retroactive entries made in the Human Resources Information System.

[18 & 19] These are combined revenues for Terasen Gas Inc. and Terasen Gas Vancouver Island which includes TGI & TGVI Gas Sales and Transportation Revenues.

[20] Includes sales for residential, commercial and industrial sectors and transportation services.

[21] This number is comprised of 509 PJ for distribution and 794 PJ for transportation.

[22 & 23] This includes the total volume numbers for TGVI (including ICLP/Hydro; VIGJV-Inland & Squamish Gas) and TGI.

[24& 25] As per note below, the low-income figures for California utilities are not included in the original stated budget amount

[26] As per Section 6 in EEC Application, $1 million has been allocated to Joint Innitiative fund which includes low-income initiatives

[27&28] Note this figure is based a minimum amount of $1.3 million as stated in the note below for both Union Gas and EGD

[29] This figure is based on 13% of the total DSM budget at Gaz Metro

[30] As per note note, $315,051 is allocated towards low-income natural gas programs for PSE

21.0 Reference: Exhibit B-2, BCUC IR 29, p.60

21.1 Do the Companies agree with the EEAH Working Group definition of low-income as being defined by LICO?

Response:

The definition of LICO is part of the Terms of Reference document that was developed for the EEAH Working Group in June 2008; it provides the following definition:

Low-income - measures of low income known as low income cut-offs (LICOs) were first introduced in Canada in 1968 based on 1961 Census income data and 1959 family expenditure patterns. At that time, expenditure patterns indicated that Canadian families spent about 50% of their total income on food, shelter and clothing. It was arbitrarily estimated that families spending 70% or more of their income (20 percentage points more than the average) on these basic necessities would be in "straitened" circumstances. With this assumption, low income cut-offs have been updated yearly by changes in the consumer price index[17].

This document was submitted in response to BCUC IR1, 29.1; it is a working document developed for and by EEAH Working Group. During the EEAH meetings, it was acknowledged that this is a broad definition that should be used as a guideline by members of the Group. As it stands now, the Companies concur with the EEAH that LICO is a broad definition of low income.

21.2 What percentage of BC residents are below LICO?

Response:

Statistics Canada's most recent publication on the topic of Low Income Cut-offs ("LICO") is entitled "Low Income Cut-offs for 2006 and Low Income Measures for 2005." The purpose of this document is to provide the income cut-offs used to define the low income population. LICO thresholds are determined by family size, community size and type (i.e., rural vs. urban which is further broken down by size of town/city). In addition, Statistics Canada produces two sets of low income cut-offs and their corresponding rates—those based on total income (i.e., income including government transfers, before the deduction of income taxes) and those based on after-tax income. Derivation of before-tax versus after-tax low income cut-offs are each done independently. Although both sets of low income cut-offs and rates are provided in this document, Statistics Canada prefers the use of the after-tax measure for two main reasons. First, income taxes and transfers are essentially two methods of income redistribution. The before-tax rates only partly reflect the entire redistributive impact of Canada's tax/transfer system because they include the effect of transfers but not the effect of income taxes. Second,

[17] Source: http://www.toronto.ca/wards2000/profile_glossary.htm

since the purchase of necessities is made with after-tax dollars, it is logical to use people's after-tax income to draw conclusions about their overall economic well-being.

Research of both federal (Statistics Canada) and provincial (BC Stat) websites showed that information for percentage of BC residents who fall below LICO is not available through free publications. BC Stats produced a custom-report at the Companies' request with the following information:

	2002		2003		2004		2005		2006	
Percentage of persons in low income	**Low income cut-offs after tax, 1992 base**	**Low income cut-offs before tax, 1992 base**	**Low income cut-offs after tax, 1992 base**	**Low income cut-offs before tax, 1992 base**	**Low income cut-offs after tax, 1992 base**	**Low income cut-offs before tax, 1992 base**	**Low income cut-offs after tax, 1992 base**	**Low income cut-offs before tax, 1992 base**	**Low income cut-offs after tax, 1992 base**	**Low income cut-offs before tax, 1992 base**
All persons	16	21.1	15.4	20.5	14.1	19.1	13	17.7	13	16.9
Persons under 18 years	18.3	24.2	19	24.4	18	23.3	15.2	21.1	16.1	21.9
Persons 18 to 64 years	16.1	20.2	15.3	19.4	14.1	18.6	13.3	17.4	13.5	16.6
Persons 65 years and over	11.7	20.4	10.4	19.7	8	14.8	7.8	13.8	5.6	11
Males	15.8	20.5	15	19.9	13.5	18.1	12.6	16.7	12.7	16.1
Females	16.2	21.6	15.8	21.1	14.7	20	13.3	18.6	13.2	17.7

Notes:

Before-tax low income cut-offs (1992 base) were determined from an analysis of the 1992 Family Expenditure Survey data. These income limits were selected on the basis that families with incomes below these limits usually spent 54.7% or more of their income on food, shelter and clothing. Low income cut-offs were differentiated by community size of residence and family size.

After-tax low income cut-offs (1992 base) were determined from an analysis of the 1992 Family Expenditure Survey data. These income limits were selected on the basis that families with incomes below these limits usually spent 63.6% or more of their income on food, shelter and clothing. Low income cut-offs were differentiated by community size of residence and family size.

The percentage of persons in BC in the table above that are below the LICO of 16.9% (all persons 2006 before tax) appears to agree with BC Hydro's estimate of 17% of its customers being below the LICO provided in the Residential Inclining Block ("RIB") proceeding (see for example BC Hydro RIB proceeding Exhibit B-3, response to BCUC IR 1.12.8.1). Since these results have been derived differently, further analysis would be required to confirm the validity of this comparison. However, the percentage of persons in BC below the LICO based on the 2006 after tax result in the table above is somewhat lower at 13%.

21.3 What percentage of the Companies' customers are below LICO?

<u>Response:</u>

The Companies do not collect information about their customers' income; therefore it is impossible to verify what percentage of customers fall below LICO. The latest REUS (Residential End-Use Study) conducted in 2002 and published in 2003 collected information about family income; however, given that about one-fifth of respondents declined to report their household income and the TGVI customers did not participate in the study, it would be impossible to estimate with confidence the percentage of customers who fall below LICO (particularly on the after tax basis preferred by Statistics Canada). However, the Companies plan to conduct another REUS that would include both TGI and TGVI customers and an effort will be made to collect information about LICO levels to the extent possible. The study will commence in late 2008 and results should be available in late 2009.

21.4 If the information for 21.3 is not available, do the Companies agree that it is reasonable that the percentage of British Columbians below LICO is roughly representative of their residential customers below LICO?

Response:

As per response in BCOAPO IR 1.21.3 above, information on the percentage of the Companies' customers who fall below LICO is not available. Since the Companies cannot verify or compare Statistics Canada's information with our own, we cannot agree that it is reasonable that the percentage of British Columbians below LICO is roughly representative of our residential customers below LICO.

22.0

22.1 Please provide the number of residential disconnections due to non-payment or accounts in arrears each year for the past five years.

Response:

The Terasen Utilities do not track collection statistics by customer class. All of the statistics referenced below include both residential and commercial activity. Residential activity represents approximately 90% of our customer base.

	Non-Pay Disconnects	Average Number of Accounts in Collections
2007	26,902	90,885
2006	26,740	91,081
2005	25,267	86,289
2004	33,123	86,432
2003	41,494	89,427

The average number of accounts in collections is the monthly average number of accounts where payment was not received by the due date on the bill.

22.2 Please provide the same analysis as 21.2 for the number of accounts in collection that did not get disconnected.

Response:

The table below reflects the number of residential and commercial accounts which, on an annual basis reached the stage in collections where the account qualified to be disconnected. Of the accounts qualifying for disconnection, 85.5% of the accounts in arrears are satisfied prior to disconnection.

	Notices of Disconnection	Non-Pay Disconnects	Payments Received
2007	208,890	26,902	181,988
2006	203,537	26,740	176,797
2005	190,619	25,267	165,352
2004	215,258	33,123	182,135
2003	241,860	41,494	200,366

22.3 Please provide the cost of collection and disconnection to the utility on an annual basis.

Response:

Effective January 1, 2002 Terasen Gas negotiated an outsourcing agreement with CustomerWorks LP for all of the meter to cash services including call handling, billing, meter reading and collections. The cost per customer is a bundled annual cost per customer per year. Terasen Gas does not have access to the detailed cost breakdown related to each of the services covered by the outsourcing agreement. The current cost per customer per year is $55.97

The disconnection cost charged to the customer is specified in the tariff and is $55 for a daytime reconnection and $95 for an after-hours reconnection. This cost includes both the cost of the disconnect and reconnect. There is no separate charge for disconnections only.

23.0 Reference: BCUC IR Response 13.1

The Table provided in response shows nominal commodity costs out to 2036.

23.1 In the Companies' view, do the nominal gas costs presented in this table represent a best estimate as to future commodity prices? If not, why not?

Response:

The nominal gas costs presented in the table are primarily based on an underlying commodity forecast prepared by GLJ Petroleum Consultants (GLJ). GLJ is one of several entities that prepare forecasts and so it is the case that there are always a range of views on future gas prices at any point in time. GLJ has been in business for over 35 years and is considered a reputable source in the industry. GLJ update their forecasts on a quarterly basis and do a comprehensive review of information that is available at the time the forecast is prepared.

23.2 Do the Companies have any view as to the availability of physical commodity supply through the year 2036?

Response:

It is the Companies view that physical commodity supply will continue to be available through the year 2036. The Companies have provided information on resource estimates in Section 6.3.1 and Section 3.1 of Appendix L in its 2008 Resource Plan submitted to the Commission June 27, 2008. Resource estimates for BC include 98 Tcf for conventional supply and over 600 Tcf of other supply including coalbed methane, tight gas and shale gas. Recent exploration and land sales in the Montney and Horne River regions of Northeast BC indicate the possibility for shale gas to become a significant new supply source in the near future. Current BC production is approximately 1.2 Tcf per year.

24.0 Reference: BCUC IR Response 14.1

24.1 Is it the Companies' view that the price signal that customers respond to is a commodity-only price or a delivered commodity price?

Response:

Regression analysis of consumption against both commodity-only price and delivery commodity price has shown that both can be considered a price signal that customers respond to. When considering delivered commodity price, the regression models show a stronger correlation, and therefore those are the prices used when analyzing price elasticity.

25.0 Reference: BCUC IR Response 14.2

25.1 Please confirm that this response indicates that residential own price elasticity has a magnitude of 0.21 and commercial own price elasticity has a magnitude of 0.17.

Response:

It is confirmed that the residential own price elasticity has a magnitude of 0.21 and commercial own price elasticity has a magnitude of 0.17.

25.2 Please provide any reasons known to the utility as to why commercial demand is less elastic than residential demand.

Response:

The Terasen Utilities assume commercial demand is less elastic than residential demand since commercial customers would have more process driven loads which are less likely to change as natural gas prices fluctuate. Also, there is the potential opportunity for commercial customers to flow through increased natural gas costs to their customers.

25.3 Please confirm that for inelastic demand, i.e., demand which has an elasticity of magnitude less than 1.00, an increase in price will increase total spending by consumers.

Response:

For inelastic demand (demand which has an elasticity of magnitude less than 1.00), a percentage change in price will lead to a smaller percentage change in demand. For most goods, including natural gas, an increase in price will lead to a decrease in demand for that good. For Giffen goods, an increase in price will lead to an increase in demand for that good. In both cases, the magnitude of the change in demand will be less than the magnitude of the change in price (so long as demand is inelastic).

26.0 Reference: BCUC IR Response 16.3.1

The attached table indicates that both Union Gas Limited and Enbridge Gas Distribution Inc. recover DSM costs in rate base.

26.1 Please provide evidence supporting this contention.

Response:

To clarify, the response to BCUC IR 1.16.3.1 table indicates that both Union Gas Limited and Enbridge Gas Distribution recover DSM costs through "the rate base", which should have been stated as "DSM costs are recovered through rates" (note that the revised version of the Table filed included in the response to BCOAPO IR# 1.20.1 reflects this correction). As per EB-2005-0020 Rate Order (which was the first rate order incorporating results of the DSM Decision), page 4, paragraph 7 states:

> *"In accordance with the EB-2006-0021 Decision with Reasons on Demand Side Management, the 2007 budget for direct and indirect DSM costs shall be $17.0 million ($15.3 million for direct costs and $1.7 million for indirect costs), an increase of $11.3 million over the amount included in existing rates. This increase will be reflected in rates effective January 1, 2007. The DSM budget shall escalate by 10% annually to $18.7 million for 2008 and $20.6 million for 2009. These budget increases shall be reflected in rates effective January 1, 2008 and January 1, 2009 respectively[18]."*

Further, both utilities earn on DSM through a Shared Savings Mechanism as described in the response to BCUC IR 1.43.2.4.6.

26.2 Please reconcile this with the following statement taken directly from Union's 2007 rate filing (OEB Docket No. EB-2005-0520, Exhibit D1, Tab 7, page 4 of 7): *"For 2007, Union proposes a total DSM budget of $15.0 million. This budget includes $12.3 million for direct program costs, research and evaluation and direct salaries, $1.7 million in indirect salaries and related costs and a market transformation budget of $1.0 million. <u>Union proposes to recover these costs in 2007 rates</u>."* (Emphasis added.)

Response:

Please refer to the response to BCOAPO IR 1.26.1.

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[18] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf

27.0 Reference: Exhibit B-1, Section 3.6, p. 41, Carbon Tax

27.1 Please explain why savings due to the carbon tax should not be credited to the carbon tax program.

Response:

Please see the response to BC Hydro IRs 1.3.1, 1.3.2 and 1.3.3. Customers that install an efficient appliance or design a more efficient building as a result of the Companies' EEC initiatives will use less gas, and will therefore pay less carbon tax. Therefore, customer bill savings from avoidance of the carbon tax through reduced usage of natural gas resulting from the Companies' EEC activity should be one of the "benefits" in the cost-benefit analysis presented in Section 6.13 of Exhibit B-1. This can be seen in Appendix 11 to which Section 6.13 makes reference.

28.0 References: Exhibit B-1, Section 5, p. 47, Program Principles
Exhibit B-1, Section 6.13, p. 84, Portfolio Approach
Exhibit B-2, BCUC IR 85.1, Attachment 85.1, p. 39
Exhibit B-2, BCUC IR 71.4, Attachment 71.4, p.21

28.1 The first principle is universality. Please indicate how the Companies intend to ensure equal access to low income consumers, given the recognition that traditional incentive based DSM programs are not accessible to them.

Response:

Please see Section 6.6.1 of Exhibit B-1, the Application, for a discussion of the Companies' proposed approach to low income consumers. Funding for a DSM program for the Companies' low income customers is proposed to come from the Joint Initiatives program area, and the nature of any program offered by the Companies to low income customers will be based upon input from, and the Companies' participation in the Energy Efficiency for Affordable Housing Group . Since BC PIAC is also a member of the Energy Efficiency for Affordable Housing Group, BC PIAC has a good opportunity to provide the Companies with advice about program design for the low income sector. The responses to BCUC IR 1.29.1 and BCUC IR 1.58.1 provide more information about the Companies' proposed approach to this sector.

28.2 Please indicate whether it is the Companies' intention to target an amount of spending at low income residential customers reflecting their proportion of residential customers.

Response:

Please see the response to BCUC IR 1.58.1. It is the Companies' intent to build a program for low income residential customers and therefore a budget as has been done for the Residential and Commercial Energy Efficiency and Residential Fuel Switching program areas, rather than targeting an amount of spending for low-income customers on a percentage basis. First of all the measures included in such a program need to be determined, then the incentive levels needed to spur participation need to be developed along with estimates of participation and finally non-incentive program costs need to be estimated. As noted in the response above, it is the Companies' intent to do this program/budget development work with input from the Energy Efficiency for Affordable Housing Group.

29.0 Reference: Exhibit B-1, Section 6.1, Table 6.1a, page 50

29.1 Of the total fuel switching activities the Companies are contemplating in this filing, what proportion will be aimed at heating oil users, electricity users, wood users, and other energy source users respectively?

Response:

Please see the Companies' response to BC Hydro IR 1.1.1.

29.2 Of the $3.699 M the Companies propose to spend on residential fuel switching, please provide figures breaking down by fuel type (heating oil, electricity, etc.) how much the Companies anticipate spending to incite fuel switching to Natural Gas.

Response:

Please see the Companies' response to BC Hydro IR 1.1.1.

30.0 Reference: Exhibit B-1, Section 6.5, Conservation Education and Outreach Program Area

30.1 Please indicate how the budgeted amount of $13.8 million was determined.

Response:

Please see Exhibit B-1, Appendix 8.

30.2 Please indicate how it will be possible, after the fact, to determine the effectiveness of this spending.

Response:

Please see Exhibit B-1, the Application, page 83, as well as the response to BCUC IR 1.47.1 for a discussion of how the Companies propose to track effectiveness of the Conservation Education and Outreach expenditures.

30.3 Please indicate whether any metric or benchmark will be available to evaluate the efficacy of this program.

Response:

Please see the response to IR 30.2, above. At this time, the Companies are proposing to perform tracking to determine whether or not the expenditures are prompting behaviour or equipment changes by customers. Based upon the responses, the Companies propose to develop energy savings estimates from those behaviour or equipment changes, as well as a protocol for cost-benefit analysis from expenditures in the Conservation Education and Outreach program area, which would be submitted with the Application for the next tranche of EEC funding, which is currently scheduled for 2010.

30.4 Please indicate how, at a high level, the Companies will specifically attribute results to this program.

Response:

Please see the responses to BCOAPO IR 1.30.2 and 1.30.3.

31.0 Reference: BCUC IR Responses 30.1 and 30.3

31.1 Do the responses given in respect of support for audits and their co-funding (or lack thereof) indicate that approval of the Application amounts to giving the Companies a blank cheque, at least to some extent? If not, please explain why not.

Response:

No, approval does not amount to giving the Companies a blank cheque. The Companies have developed certain program areas and budgets for specific activities within those program areas. The Companies have proposed that the portfolio of EEC activities made up by the different program areas must maintain an overall portfolio level TRC of 1.0 or greater, which will ensure that the Companies engage in activities that provide an overall benefit. As outlined in Section 6.14.2, the Companies are proposing to engage a Stakeholder group to give it advice and input on program design. The following is an excerpt from page 89 of Exhibit B-1:

> *"The Companies propose to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress. <u>The workshops would also be a forum for stakeholder input on developing new programs and refining existing programs, as well as providing some opportunity for oversight and comment</u> by the Stakeholders on the Companies' EEC activity." [emphasis added]*

Also, as outlined in Section 6.14.1, the Companies propose to provide an Annual Report to the Commission. And finally, as noted in the response to BCOAPO IR 6.1, the Companies intend to submit future requests for EEC expenditures in future years, as outlined on page 50 of Exhibit B-1. Presumably if the Companies are prudent in managing any EEC expenditures approved as a result of Exhibit B-1, the Application, future EEC Applications will not be successful. It is for all these reasons that approval of the Application as written does not amount to giving the Companies a blank cheque.

32.0 Reference: Exhibit B-1, Section 6.6, Joint Initiatives

32.1 Please provide a breakdown of expenditures for each of the four programs sharing the Joint Initiatives funding.

<u>Response:</u>

As noted in the response to BCUC IR 1.30.1, BCUC IR 1.31.3 and BCUC IR 1.58.1, the exact expenditure breakdowns for each of the four programs sharing the Joint Initiatives have not yet been developed.

33.0 Reference: Exhibit B-1, Section 6.6, Joint Initiatives

Gerry Gaudreau, executive director of the Manitoba Public Utilities Board stated at CAMPUT 2008 that low-income folks are subsidizing the DSM measures of their middle and high income counterparts as they pay the same rates with little or no chance to participate in DSM programs.

33.1 Please comment on the statement above.

Response:

Without more information about the context of this statement attributed to Mr. Gaudreau, and a better understanding of same, the Companies are not comfortable commenting extensively on this assertion. However, this statement may be correct in instances where DSM programs offer incentives that only offset part of the incremental cost of efficient equipment. The most common types of DSM programs usually require some sort of capital outlay as in programs that offer a rebate to the rate payer on the purchase of energy efficient appliances or the upgrading of a furnace or fireplace. It can be challenging for a household that has already stretched its budget to the limit to find the extra funds needed to purchase these rebate-eligible items. It is for this reason that the Companies have proposed DSM programs targeted to low income households.

34.0 Reference: Exhibit B-1, Section 6.10, p. 78, The Industrial Sector

The evidence states that "[t]he Companies' industrial customers generally make energy efficient decisions based largely on the economic payback."

34.1 Would not commercial customers be expected to make these decisions on the economic payback also?

Response:

Yes, it is the understanding of the Terasen Utilities that Commercial customers would consider, to a certain degree, economic payback as part of its decision making process.

34.2 In the Companies' view why would non-low income residential customers not also look at the economic payback?

Response:

To clarify, the Companies have not intended to suggest that non-low income residential customers do not look at economic payback. The Companies expect that non-low income residential customers do probably consider economic payback when making purchase decisions.

35.0 Reference: Exhibit B-1, Section 6.11, p. 79, Staffing Levels

35.1 Please explain why 2010 person years exceed 2009 person years by almost 70%.

Response:

A great deal of the staffing increase – 5.1 person years of the 8.7 person years – is in the area of program evaluation, as can be seen in Table 6.11 in Exhibit B-1, the Application, recognizing that the programs proposed in the Application will be ending and will therefore have to be evaluated. The remainder is in Program Operations, and is based upon an estimated cost per participant for program operations and the highest level of participation in the last year of most of the programs.

36.0 Reference: BCUC IR Response 34.1

36.1 Please explain whether the cost per GJ saved indicates that the integrated energy system program and the solar thermal programs are uneconomic at present.

Response:

As per BCUC IR1 Response 34.1, from the Table *Integrated Energy System & Solar Thermal DHW Comparison*:

a) Integrated Energy System:

The table indicates that the cost per GJ (based on 10 yr life) is $20 which is well above the cost of natural gas, and thus indicates that the integrated energy system is uneconomic at this time.

b) Solar Thermal Program

The table indicates that the cost per GJ (assessed on 25 year life) is $26 which is well above the cost of natural gas, and thus indicates that the solar thermal program is uneconomic at this time.

37.0 Reference: BCUC IR Response 37.3

37.1 In what percentage of cases do the Companies believe that by providing a $100 incentive to install individual meters or thermal metering, the contribution would entice a builder not previously disposed to do this work, install the individual meters or thermal metering?

Response:

No specific percentage number is available however because the customer/developer will incur increased cost by having to install additional piping and meter closets; and also, suffer an associated reduction in saleable square footage due to the addition of meter closets to accommodate metering equipment, the Company believes that the vast majority of customer/developers would not proceed without a monetary incentive.

37.2 Have the Companies considered the possibility of free-riding with respect to this incentive?

Response:

When considering increased installation costs to the customer/developer, the Company believes that free-riding would be minimal.

38.0 Reference: BCUC IR Response 40.1

38.1 Please discuss the possibility of rate class cross-subsidization inherent in the allocation of DSM costs by class coincident peak, without regard to spending targeted to a class or sub-class.

Response:

As with any Commission approved cost allocation methodology and rate design, whether it is a coincident peak allocation methodology or a direct assignment of costs, there is a possibility that specific rate structures may not emulate the cost of service for an individual customer or class of customers. Individual customers or sub-sets of customers within a rate class will have different consumption behaviours thereby resulting in differing cost structures, although the approved rates will be the same for all customers within the rate class. The same could be possible on an inter-rate class basis. This would likely hold true for customers with respect to the allocation of EEC related costs. Such differences are not inconsistent with the rate-setting provisions of the Utilities Commission *Act*. With this Application, the Companies are not proposing any changes to the underlying cost allocation methodologies that have been approved by the Commission in previous rate design proceedings.

39.0 Reference: BCUC IR Response 41.2

39.1 Please provide a comparable table under the assumption that DSM costs were placed in a non-rate base deferral account that attracted interest at the BCUC's currently approved interest rate for such accounts.

<u>Response:</u>

Please see financial schedule attached below.

Assumptions:

1. Include EEC expenditure of $1 million in a non-rate base deferral account, on an after-tax basis and amortize the balance for 20 years.

2. The non-rate base deferral is financed by short term debt only

3. The discount rate used is after-tax based on the short term debt rate.

The present value of the Cost of Service for 20 years (under these assumptions) is $0.910 million. This compares to the present value of Cost of Service of $0.899 million, when DSM costs are treated as capital in a rate base deferral account and amortized over 20 years as proposed in the Application. The difference is primarily attributable to the lower discount rate used under this assumption.

It should be noted that by placing DSM costs in a non-rate base deferral account, it would not be possible for the utility to earn a fair and reasonable return on the expenditures that it makes to reduce energy demands, in accordance with Section 60(b)(ii) of Utilities Commission Act.

TERASEN GAS INC.
RATE BASE / COST OF SERVICE
DEMAND SIDE MANAGEMENT
$000's

Particulars		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Rate Base - Deferred Charge																							
Opening, Balance		$ -	$ 690	$ 656	$ 621	$ 587	$ 552	$ 518	$ 483	$ 449	$ 414	$ 380	$ 345	$ 311	$ 276	$ 242	$ 207	$ 173	$ 138	$ 104	$ 69	$ 35	
Additions		1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Tax Adjustment		(310)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		690	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization Expense # of Years	20	-	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	
Closing, Balance		$ 690	$ 656	$ 621	$ 587	$ 552	$ 518	$ 483	$ 449	$ 414	$ 380	$ 345	$ 311	$ 276	$ 242	$ 207	$ 173	$ 138	$ 104	$ 69	$ 35	$ -	
Deferred Charge - mid-year		$ 345	$ 673	$ 638	$ 604	$ 569	$ 535	$ 500	$ 466	$ 431	$ 397	$ 362	$ 328	$ 293	$ 259	$ 224	$ 190	$ 155	$ 121	$ 86	$ 52	$ 17	
Unfunded Debt		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
Unfunded Debt Rate		5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	
Cost of Service																							
Amortization Expense		$ -	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 690
Income Tax Expense		-	15	14	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	248
Earned Return on Debt		17	34	32	30	28	27	25	23	22	20	18	16	15	13	11	9	8	6	4	3	1	362
Earned Return on Equity		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return on Rate Base		17	34	32	30	28	27	25	23	22	20	18	16	15	13	11	9	8	6	4	3	1	113
Total Cost of Service		$ 17	$ 83	$ 81	$ 78	$ 75	$ 73	$ 72	$ 70	$ 68	$ 66	$ 65	$ 63	$ 61	$ 60	$ 58	$ 56	$ 54	$ 53	$ 51	$ 49	$ 47	$ 1,051
Discount Rate @ after tax		3.45%	3.50%	3.55%	3.63%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
Present Value of Cost of Service @ after tax	$ 910	$ 17	$ 77	$ 73	$ 67	$ 63	$ 59	$ 56	$ 52	$ 49	$ 46	$ 43	$ 41	$ 38	$ 36	$ 34	$ 31	$ 29	$ 27	$ 26	$ 24	$ 22	

39.2 Please provide the rate impacts under such a regulatory treatment.

Response:

Rate impact is directly related to $Cost/GJ. Please see the schedule included in the response to BCOAPO IR 1.39.1.

40.0 Reference: Exhibit B-1, section 6.12, pp 81-2

40.1 Please confirm that the IFRS standards

(a) will prescribe how companies report to the financial community,

Response:

Publicly accountable enterprises will be required to prepare their financial statements in accordance with IFRS for fiscal years beginning on or after January 1, 2011. These financial statements will be filed for use by the financial community, among others.

(b) are not determinative of regulatory treatment in individual jurisdictions, and

Response:

Although regulatory treatment follows generally accepted accounting principles (in this case IFRS) where practicable, different regulatory treatments may be allowed where GAAP is not appropriate.

(c) do not constrain the BCUC in determining appropriate regulatory treatment of EEC expenditures, now or in 2011.

Response:

The BCUC is not constrained by GAAP in determining regulatory treatment.

41.0 Reference: Exhibit B-1, Section 6.13 p. 87, Attribution
BCUC IR 51.1-51.3 Responses

41.1 Please provide a list of all cases in which a Canadian regulator has pre-approved Attribution Rates such as appear in table 6.13b for a gas distribution utility.

Response:

It should be noted that the Companies are using the term "market transformation" as defined in the response to BCUC IR 1.20.1.

The Companies are not aware of any Canadian regulator that has pre-approved Attribution Rates for a gas distribution utility. The Companies are proposing the attribution rates believing them to be reasonable. As can be seen on page 87 of Exhibit B-1, it should be noted that the "attribution rates" proposed are for energy savings resulting from the introduction of a regulation for which the ground has been laid by a Terasen Utilities EEC program. The term "attribution" can also refer to the sharing of benefits when there are multiple partners involved with a specific program, as is the case in Ontario and can be seen in Section 13 of the attachment filed in response to BCUC IR 1.84.1.

41.2 Given the Companies' response to BCUC IR 51.2, what is the practical significance of the approval that the Companies are seeking. That is, the response to 51.2 seems to indicate that the attribution rates in Table 6.13b would not apply in the case of partnered efforts: in this case, what approval is sought by the Companies?

Response:

The Companies are not requesting any specific approval in this Application for attribution for partnered efforts – the attribution approval being sought in this Application is for attribution of energy savings from the introduction of regulation. Partnered efforts should have energy savings attributed on a proportional basis, and for direction on attribution from partnered efforts, the Companies will rely on the guidance of the Measurement, Evaluation and Reporting Task Force of the British Columbia Partnership for Energy Conservation and Efficiency (BCPECE). For one potential approach for attribution from partnered efforts, please see the attachment filed in response to BCUC IR 1.84.1. The Ontario Energy Board has ruled that attribution should be worked out between partners at the outset of a program, and submitted with a multi-year plan. Since the Companies have not yet worked out the details of any programs to be offered with partners, details of attribution on specific partnered programs cannot be provided.

41.3 Please confirm that if the Companies receive the approval they are seeking, once new codes, standards, or regulations come into effect, the Companies will be able to justify a higher spending on market transformation programs than they would be otherwise able to justify. If not, please explain why not.

Response:

To some degree, this is correct – higher benefits from counting savings from the introduction of utility-supported codes, standards and regulations could potentially support higher expenditures leading up to the introduction of codes, standards or regulations. However, the Companies are deeply aware of the upward pressures that higher EEC expenditures would place upon rates, and would rely on the input of the Stakeholder Group outlined in Section 6.14.2 of Exhibit B-1, to provide the Terasen Utilities with directional advice as to the appropriate levels of EEC expenditure, and the appropriate balance between expenditures on EEC activity and rate impacts from same.

41.4 Please confirm that under their proposal, the Companies' increased spending on market transformation would be reflected in a higher rate base, higher return, higher taxes, and higher amortization costs borne by ratepayers than would otherwise be the case.

Response:

Please see the response to BCAOPO IR 1.41.3 above. The rate impacts from the Companies' proposed incremental expenditures on EEC activity, as outlined in this Application, can be found on pages 95 for TGI and 97 for TGVI of Exhibit B-1. It should be noted that in general, customers benefit from market transformation, as efficiency levels are pushed ever higher through the market transformation process, thus lowering customer energy bills.

41.5 Please indicate whether the Companies would wish to modify their attribution proposal if the BCUC found that rate base treatment for EEC expenditures was inappropriate.

Response:

Modifications to the specifics of the attribution proposal included in the Application would not change the underlying rationale for the accounting treatment proposed for the EEC expenditures in the Application. Consequently the Companies do not see a linkage between the two components of the Application. The Companies view its proposed accounting treatment to be appropriate and in the best interests of customers regardless of the specifics of its attribution proposal. Please refer to the response to BCUC IR 1.10.2 for the discussion of the rationale for the proposed accounting treatment.

41.6 Referring to Table 6.13b, if 50% of the savings are attributed to the utilities' market transformation program in the first year, to what are the other 50% attributable to? Similarly, what are the savings in succeeding years that are not attributed to the market transformation program attributable to?

Response:

As noted in the response to BCUC IR 1.51.1, there are other market actors in market transformation. Designers, manufacturers, distributors, agents, retailers, installers, educators, standards bodies, regulators and policy makers all have roles to play. It is the activities performed by these other market actors that results in savings in succeeding years that are not attributed to the Companies' market transformation programs. This a relatively new area of cost-benefit analysis, and the attribution rates proposed are based on the Companies' judgment of fair and reasonable attribution rates. The Companies have recognized that it is unreasonable to request 100% attribution from the Terasen Utilities market transformation programs.

41.7 Please describe and quantify the benefits and costs to ratepayers of the Companies' attribution rate proposal.

Response:

The Companies have calculated the Total Resource Cost test result to have a TRC ratio of 2.9., and a net financial benefit of $139.4 million including free rider effects, and a TRC ratio of 3.1 and net financial benefit of $165.1 million excluding free rider effects. Energy savings from attribution as defined on page 87 of Exhibit B-1 are not included in these calculations.

42.0 Reference: Exhibit B-2, BCUC IR 2.2

42.1 Please explain the Companies' rationale for not attempting the Societal test, given that the Summit Blue report (Attachment 85.1) states that it is one of the two most important tests

Response:

Please see the response to BCUC IR 1.2.4. The Summit Blue report referred to in the Information Request defines the Societal test as follows:

> *"The societal test is very similar to the TRC test, except that it includes avoided environmental damages due to DSM programs."*

The Companies have performed the TRC test. The Companies have not attempted the Societal test, as there has been no protocol developed in British Columbia around what inputs for environmental damages to the Societal test might be appropriate, and how to monetize the value of those inputs. It is the Companies' view that this should be one of the outcomes of the work of the Evaluation Working Group of BCPECE.

42.2 In the Companies' view, which of the following should be included in the Societal test

(a) Reducing homelessness;
(b) Improving health;
(c) Reducing excess winter deaths.

Response:

As noted in the response to IR 42.1 above, the Summit Blue report referenced in the Information Request above refers to avoided *environmental* damages [emphasis added]. The items in IR 42.2 above are not environmental damages. The Companies' view is that the appropriate inputs to the societal test should be determined by the Evaluation Working Group of the BCPECE.