Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

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

August 15, 2008

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

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 Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

On May 28, 2008, the Companies filed the Application as referenced above. In accordance with Commission Order No. G-102-08 setting out the Preliminary Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to BCUC IR No. 2.

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 (e-mail only): Registered Parties

1.0 Reference: Exhibit B-2, BCUC IR#1 1.2 and Exhibit B-2-1, Duration of Energy Savings

1.1 It appears that energy savings are assumed to be credited to each program for the life of the measure implemented, and that this time span is not adjusted for the natural adoption rate of the technology that would have occurred in the absence of the program. Please comment. Was the age and remaining life of the existing appliance stock considered?

Response:

The age of the existing stock of appliances is considered in that the uptake rate is driven by a "capital stock turnover" model which estimates the number of appliances that become available and is developed based on the shares of the appliance in the customer base and the life expectancy of the appliance. Remaining life is not considered as appliances are assumed to be replaced at the end of their useful life.

Once an efficient appliance is installed, the savings are available to the utility for the life of that appliance. Natural adoption does not affect the duration of the savings from the product.

1.2 Has Terasen considered both measure and claim persistence in calculating the savings attributed to the programs? If so, please explain in detail.

Response:

Measure persistence refers to the risk of a measure being discarded or replaced before the end of its expected life, and is a concern if the product is replaced with a less efficient unit. For the measures being considered in these programs (ie: furnaces, fireplaces, major appliances in residential buildings, building shell measures, and major water and heating equipment in commercial buildings), early replacement with less efficient equipment was not considered a significant risk, due to the high cost and inconvenience of doing so, and was not explicitly considered.

2.0 Reference: Exhibit B-2, BCUC IR#1 2.1 and 2.2, and Attachment 71.4

2.1 In its response to question 2.1 Terasen states that the Overall EEC Portfolio means the entire slate of EEC Activity including various activities which it then lists. Please provide a calculation of the Total Resource Cost ("TRC") assuming the Overall EEC Portfolio minus all residential fuel switching and innovative technologies.

Response:

The TRC for the Overall EEC Portfolio minus the costs and benefits associated with residential fuel switching, and minus the costs associated with Innovative Technologies is 2.4 including free riders, and 2.8 excluding free riders.

2.2 Terasen states in its response to question 2.2 that the Companies are not making any proposal with respect to threshold values for the Utility Cost Test or RIM.

2.2.1 Are the Companies proposing, or making a recommendation with respect to criteria about accessibility of programs to low-income customers?

Response:

The Companies are proposing to rely on input from the Energy Efficiency for Affordable Housing Working Group in establishing criteria about accessibility of programs to low-income customers.

2.2.2 What percentage of residential programs (a) by level of anticipated savings and (b) by expenditure level, are aimed at low income customers?

Response:

A budget for a program specifically for low-income customers has not yet been established. The proposed process for establishing such a budget is outlined in the response to BCOAPO IR 1.28.2.

2.2.3 Does Terasen consider it useful to consider rate impact (i.e. the RIM) of programs in the absence of any other measures to assess the accessibility of programs to low-income consumers? Please explain your answer.

Response:

The Companies propose that the most appropriate way to assess accessibility of programs to low-income customers is through input from the EEAHG and from the Companies' proposed Stakeholder group. As noted in the response to IR 2.2.2 above, the Companies propose to develop a budget amount for low-income programming "from the ground up". The Companies' view is that the RIM cost-benefit test does not provide any information about the accessibility of programs to low-income consumers. Rather the RIM test provides directional information about pressures upon rates.

2.3 The OEB decision (Attachment 71.4, page 33) concludes that the utilities should allocate a proportion of their DSM budgets to low income households. Does Terasen support that approach, or an approach in which no funding is allocated to low-income customers, or one in which low-income funding is provided by another entity (e.g. government)? Please explain your answer.

Response:

The Terasen Utilities support an approach to develop a budget and programs for the low-income segment similar to that taken for other residential and commercial energy efficiency programs. That is, to do some initial program development with an outline of the measures included in that program, then to develop estimates of the incentive levels needed to spur program participation, and therefore participation rates, and finally to develop estimates of non-incentive costs. The Companies' view is that this "bottom up" approach is preferable to prescriptive levels of spending on low-income programs. Certainly government funding of incentives has a role to play in a successful low-income program, since the incentives required to spur participation will be higher than incentives required in the able-to-pay segment.

3.0 Reference: Exhibit B-2, BCUC IR#1 2.4 and 18.2

On page 4 of its responses to BCUC Information Requests, Terasen states that the Companies included the avoided Carbon Tax in the participant benefits, "…as can be noted in Appendices 11A and 11B…." A copy of the Ministry of Small Business and Revenue Carbon Tax Rates by Fuel Tax is attached as Attachment 1 to this Information Request.

Attachment 1:

Ministry of Small Business and Revenue

British Columbia
The Best Place on Earth

www.gov.bc.ca/sbr

June 20, 2008

Carbon Tax Rates by Fuel Type						
	Units for Tax Rates	July 1 2008	July 1 2009	July 1 2010	July 1 2011	July 1 2012
Liquid Fuels						
Gasoline	¢/Litre	2.34	3.51	4.68	5.85	7.02
Light Fuel Oil *	¢/Litre	2.69	4.04	5.38	6.73	8.07
Heavy Fuel Oil	¢/Litre	3.15	4.73	6.30	7.88	9.45
Aviation Fuel	¢/Litre	2.46	3.69	4.92	6.15	7.38
Jet Fuel	¢/Litre	2.61	3.92	5.22	6.53	7.83
Kerosene	¢/Litre	2.54	3.81	5.08	6.35	7.62
Naphtha	¢/Litre	2.55	3.83	5.10	6.38	7.65
Methanol	¢/Litre	1.09	1.64	2.18	2.73	3.27
Gaseous Fuel						
Marketable Natural Gas	¢/GJ** or ¢/M^3 ***	49.66 1.90	74.49 2.85	99.32 3.80	124.15 4.75	148.98 5.70
Raw Natural Gas	¢/M^3 ***	1.90	2.85	3.80	4.75	5.70
Propane	¢/Litre	1.54	2.31	3.08	3.85	4.62
Butane	¢/Litre	1.76	2.64	3.52	4.40	5.28
Ethane	¢/Litre	0.98	1.47	1.96	2.45	2.94
Refinery Gas	¢/M^3***	1.76	2.64	3.52	4.40	5.28
Coke Oven Gas	¢/M^3***	1.61	2.42	3.22	4.03	4.83
Solid Fuels						
Low Heat Value Coal	$/Tonne	17.77	26.66	35.54	44.43	53.31
High Heat Value Coal	$/Tonne	20.77	31.16	41.54	51.93	62.31
Coke	$/Tonne	24.87	37.31	49.74	62.18	74.61
Petroleum Coke	¢/Litre	3.67	5.51	7.34	9.18	11.01
Combustibles						
Tires – shredded	$/Tonne	23.91	35.87	47.82	59.78	71.73
Tires - whole tires	$/Tonne	20.80	31.20	41.60	52.00	62.40
Peat	$/Tonne	10.22	15.33	20.44	25.55	30.66

* Light fuel oil – subcategories of light fuel oil include:

- diesel,
- locomotive fuel, and
- heating oil.

** GJ = Gigajoule

*** M^3 = cubic meters

PO Box 9442 Stn Prov Govt Victoria BC V8W 9V4

3.1 Has Terasen included the tax on natural gas in the same amounts, escalated at the same rates over time, as the tax rates established by the Ministry of Small Business and Revenue document? What value has Terasen assumed for the Carbon Tax in the years after 2012?

Response:

Yes, Terasen has included the Carbon Tax as originally established by the Ministry of Small Business and Revenue. The cost-benefit analysis included in Appendix 11 to Exhibit B-1 was undertaken at the end of March 2008 and was based on information about carbon tax rates made available by the Government of British Columbia at that time. On June 10, 2008, the Government of British Columbia modified the carbon tax rates slightly from those originally published. The difference between the carbon tax rate used by the Terasen Utilities in the EEC analysis and the amounts finalized by government are minimal at less than one cent.

Carbon Tax Rates for Natural Gas					
$/GJ	**July 1 2008**	**July 1 2009**	**July 1 2010**	**July 1 2011**	**July 1 2012**
Terasen Utilities DSM Plan - Carbon Tax Rate Used	$0.4988	$0.7482	$0.9976	$1.2470	$1.4964
Ministry of Small Business and Revenue – Marketable Natural Gas	$0.4966	$0.7449	$0.9932	$1.2415	$1.4898

The model leaves the Carbon Tax flat at the 2012 rate until the end of the measure periods

3.2 On page 45 of its response to BCUC IR#1 18.2, Terasen states that the BC Carbon tax is a further mechanism being adopted to reduce fossil fuel (i.e. gasoline) usage. Can Terasen confirm that natural gas is being taxed in the same manner as gasoline (although in a different amount) and therefore that the BC Carbon tax is a further mechanism being adopted to reduce fossil fuel (i.e. natural gas) usage?

Response:

Confirmed. The BC Carbon Tax applies to the combustion of all fossil fuels in BC. The tax rate is based on the carbon dioxide emissions resulting from the fuel, starting at a rate of ten dollars per tonne of carbon dioxide equivalent. This equates to an initial tax rate of $0.4966 per gigajoule (GJ) of natural gas consumption, based on the Ministry of Small Business and Revenue update, dated June 20, 2008.

It is the Company's position that the Carbon Tax is one of the provincial government's strategies to change energy use in the province and reduce GHG emissions. Other such strategies include appliance standards and building code changes. With the

Carbon Tax tied to carbon dioxide emissions from fuels, natural gas has an advantage compared to other fossil fuels such as gasoline and propane. Therefore, use of natural gas could actually expand in the province, as companies and households consider the Carbon Tax in their decision making process.

4.0 Reference: Exhibit B-2, BCUC IR#1 3.3 and 3.1, Free Ridership

4.1 Question 3.3 asked if the Companies have any evidence that forecasts of free ridership were any more or less uncertain than forecasts of (say) penetration rates. The answer referred to BCUC IR#1 3.1, which submits that free rider estimates are based more on art than on science, and quotes from the U.S. National Action Plan for Energy Efficiency's Model Energy Efficiency Program Evaluation Guide which states that the analysis of spillover and free ridership is complicated by "market noise".

Do the Companies have any evidence of the relative uncertainty of free ridership estimates versus other inputs and forecasts used in designing and evaluating EEC programs? If so, please provide it.

Response:

Research uncovered a number of studies that discuss the relative uncertainty of free ridership estimates. Please refer to the quotes below:

William P. Saxonis from the New York State Department of Public Service, Albany, NY, in his paper titled Free Ridership and Spillover: A Regulatory Dilemma, argues that free ridership measurement techniques still suffer from a fairly high degree of uncertainty:

> *Over the past three decades, free rider measurement techniques have steadily improved, but there remains a notable variation in the approaches and methodologies used to identify and report free ridership in addition to legitimate questions about the reliability of the data and the role of the results. Documenting what would have happened, absent a program, remains one of the biggest challenges in energy program evaluation[1].*

Another paper, titled California 2002-2003 Portfolio Energy Efficiency Program Effects and Evaluation Summary Report, prepared by TecMarket Works for Southern California Edison and the Project Advisory Group, points out that caveats usually surround free rider estimates, even in the most recent and rigorous program evaluations. In reviewing energy program evaluations for the California 2002-2003 program portfolio, the authors concluded that, in general, evaluation results suffered from three key problems: incompatibility, incompleteness and a lack of rigor. The study also went on to highlight that less than half of the evaluations took free ridership into consideration when reporting energy savings, covering only 29 percent of the reported kWh savings:

> *However, it should be noted that the issues of identifying free-riders are complicated and estimating highly reliable program-specific free ridership is problematic at best. This is especially true in states like California that have had strong and on-going programs that may have caused the participant to seek the action taken one or more years before the enrollment date.*

---

[1] http://www.iepec.org/2007PapersTOC/papers/62_1064_ab_585.pdf; p.536

The U.S. National Action Plan for Energy Efficiency's Model Energy Efficiency Program Evaluation Guide, mentioned in IR#1 3.3 and 3.1, defines net savings and describes the four key factors that differentiate net and gross savings: free ridership, spillover effects, rebound effects, and electricity transmission and distribution losses. The guide also argues that the analysis of spillover and free ridership is complicated by "market noise."[2]

Further, Mark Jaccard, SFU, in his paper titled "Shifting Rationales for Energy Regulation and Regulatory Dilemmas," states that:

> *In general, this research indicates the need for significant downward adjustment of initial assumptions about the effectiveness of information and subsidy programs. A critical reason is the impossibility of stopping free-riders from benefiting from subsidy programs. Free-riders are firms and households who would have made the energy or GHG reducing investment even without the subsidy. Their investments are part of the baseline energy efficiency trend of the economy even in the absence of energy efficiency reduction policy – a trend that has been observed since at least the 1950s. It is impossible to know exactly the number of free-riders for a given program. We would have to replay history to be certain[3].*

Finally, authors of the Evaluating the Impact of Labeling and Standard Setting Programs in Section 9.6 discuss evaluation issues, including free ridership, associated with DSM programs:

> *It can be especially challenging to evaluate free ridership for labeling programs when other market transformation programs, such as rebates for efficient appliances, are in place. Because these market transformation campaigns are specifically designed to create—over time—a situation in which purchasing energy efficient appliances is common practice even in the absence of any program, it is difficult to estimate the increasing rate of efficient purchasing that would result if only the other market transformation programs were in place. Because estimating the free rider effect is difficult, simple and highly uncertain assumptions are often made about free ridership. If resources are not available for conducting a sophisticated analysis, evaluators may be able to use other sources that implicitly address this issue (e.g., comparing to appliance investment behavior in other regions or in other countries where there are no appliance labeling or standards-setting programs)[4].*

It should be noted that free riders are not a planned factor in DSM programs and can be evaluated either explicitly or implicitly (Goldbergy and Schlegal 1997; Saxonis 1991)[5]. The majority of free riders studies rely on subjective, after-the fact reports from the

[2] http://epa.gov/cleanrgy/documents/evaluation_guide.pdf p. 5-2
[3] http://www.camput.org/documents/2006-04-12JaccardpaperCamput2006.doc p.250
[4] http://www.undp.org/gef/05/programming/sl_site/sl_image/Ch9_GB2ndEdition.pdf
[5] http://www.iie.org/programs/energy/pdfs/Monitor%20Verif%20Climate%20Change.pdf p.26

participants and non-participants about hypothetical situations (i.e., what they think they would have done if circumstances had been different), while other studies attempt to utilize inputs derived from more concrete sources such as participants rates and energy savings derived from installed measures (keeping in mind that participants' numbers are tracked during program implementation stage and savings for each measure are calculated).

The negative impact of free riders is that they tend to reduce the net benefits of DSM programs. Also, evaluation studies that take free riders into consideration tend to be most costly which increases overall costs of the program. Although the uncertainty of free ridership estimates need to be taken into consideration, utilities should keep in mind the amount of resources directed towards counting these estimates.

4.2 Does Habart and Associates usually produce free ridership and net to gross estimates when it evaluates programs? If so please summarize the results for all Terasen programs reviewed by Habart.

Response:

Habart & Associates typically include estimates of free riders (FRR) in the evaluations. Following is a list of the evaluations and the estimates.

Program	**Year**	**FRR**	**Approach**
Efficient Boiler Program	1995 - 2000	18%	Customer Survey
Winter Bill Saver Program - High Efficiency Heating System Offer	2001	14.5%	Discrete Choice
Winter Bill Saver Program - Weatherization & Insulation Offer	2001	8.5%	Discrete Choice
Summer Furnace Tune-up Program	2001	81.6%	Discrete choice
Residential Heating System Upgrade - Billing analysis (2004 – 2002 data)	2002	31.2% 20%	Trade Ally Survey Discrete choice
TG/E* Heating System Upgrade	2003	28%	Discrete choice
TG Pilot Fireplace Program	2004	24%	Customer Survey
TG 2005-07 Heating System Upgrade	2008	43%	Customer Survey

5.0 Reference: Exhibit B-2, BCUC IR#1 3.1

5.1 Do the Companies agree that netting out energy savings resulting from the participation of "free riders" in cost-benefit analyses produces the same result as if free-ridership is included as an input in the calculation but the rate of free-ridership is assumed to be zero? If not, why not?

Response:

Yes.

6.0 Reference: Exhibit B-2, BCUC IR#1 1.1 & 9.1, and Exhibit B-1, Application, Section 3.2 History of Demand Side Management Programs, pp. 22-25, Energy Star Heating System Upgrade

Table 3.2.1 on page 24 of the Application shows the savings per participant for the Energy Star Heating System Upgrade Program to be 14 GJ in 2005, 14 GJ in 2006, and 13.8 GJ in 2007.

6.1 Please explain the 0.2 GJ change from the 14 GJ to the 13.8 GJ in 2007.

<u>Response:</u>

This table is a spreadsheet and the decimal places for these particular cells were set differently. Please find a revised table below.

2005-2007 TGI Historical Program Summary

Year	Program Name	Number of Participants	Savings per Participant per Year (GJ)	Measure Life (Years)	Annual Savings (GJ)	TRC Cost Benefit Ratio	TRC Net Benefit	Costs ($000) [6]
2005	Energy Star Heating System Upgrade Program	3,000	13.8	20	41,400	1.73	n/a	
	Residential New Construction Heating Program (RNCHP)	750	9.1	20	6,825	1.85	n/a	
	Commercial Energy Assessment Program	90	600.0	15	31,500	n/a	n/a	
	Efficient Boiler Program (EBP)	15	1570.0	25	23,535	3.0	n/a	
	Destination Conservation	20	n/a [1]	3	4,000	n/a	n/a	
	Total 2005	**3,875**	**n/a**	**n/a**	**107,260**	**2.92** [4]	$ 5,800,000 [5]	**$ 1,548,336**
2006	Energy Star Heating System Upgrade Program (VSM)	2,343	13.8	20	32,333	1.29	$ 440,584	
	Energy Star Heating System Upgrade Program (No VSM)	1,220	13.8	20	16,836	1.29	$ 229,412	
	Residential New Construction Heating Program (RNCHP)	1,180	9.1	20	10,738	1.60	$ 394,026	
	Efficient Boiler Program (EBP)	30	n/a [2]	25	30,849	1.96	$ 1,671,723	
	Commercial Energy Assessment Program	18	600.0	15	10,800	2.66	$ 604,300	
	Destination Conservation	4	113.0	3	452	0.01	$ (7,987)	
	Total 2006	**4,795**	**n/a**	**n/a**	**102,008**	**1.65**	**$ 3,340,045**	**$ 2,106,192**
2007	Energy Star Heating System Upgrade Program	4,316	13.8	20	59,561	1.39	$ 1,123,000	
	Residential New Construction Heating Program (RNCHP)	2,981	9.1	20	27,127	1.73	$ 1,222,000	
	Efficient Boiler Program (EBP)	20	n/a [3]	25	14,650	1.47	$ 571,000	
	Destination Conservation	44	113	3	4,972	1.56	$ 55,000	
	Commercial Energy Assessment Program	100	600	15	60,000	3.03	$ 3,397,000	
	Total 2007	**7,461**	**n/a**	**n/a**	**166,310**	**1.85**	**$ 6,368,000**	**$ 2,108,633**

Note that the numbers above are based on combination of actual and estimates as presented in the 2005, 2006 and 2006 Annual Reviews

1 The savings for Destination Conservation were presented as an aggregate of savings in 2005

6.2 The spreadsheet contained in Attachment 1.1 shows for TGI Residential Retrofit Furnace DSM annual savings of 13.8 GJ. However, the TGVI Residential Retrofit Furnace DSM is 10.8 GJ.

6.2.1 Please provide the source calculation of the 10.8 GJ TGVI savings.

Response:

The estimate of 10.8 GJ savings for TGVI was taken from the Conservation Potential review, and reflects the lower energy consumption of housing on Vancouver Island. The savings estimate is based on an estimated 18% reduction in consumption when moving from an 80% mid efficient furnace to a 94% high efficiency furnace. The 13.8 GJ number used for the Lower Mainland and the Interior is based on program evaluations in those regions.

6.2.2 Please explain why the TGVI savings are different from the TGI savings. Please reconcile the difference.

Response:

Please see the response to BCUC IR 1.6.2.1 above.

6.3 Terasen's response to IR#1 9.1 states that the Energy Star Heating Upgrade program induced participants to install a new furnace 2.3 years earlier than would otherwise be the case and explains the calculation. Please explain the basis on which Terasen calculates that the savings going from a standard to high efficiency furnace are the result of the program and that it persists for 25 years.

Response:

The evaluation approach for determining the savings from the program are as follows.

If the furnace is replaced upon failure of the old furnace, the savings claimed are the difference in consumption between a mid-efficiency furnace and a high efficiency furnace (12.6 GJ), not the difference between a standard efficiency furnace and a high efficiency furnace (21.3 GJ). These savings numbers were developed as part of the billing analysis in the changed consumption of program participants conducted in 2004 (on customers from the 2002 program). The reason for claiming the smaller savings number is that furnace efficiency regulations require that a mid-efficiency furnace be used, so the 8.7 GJ savings resulting from the replacement of a standard efficiency furnace with a high efficiency furnace would occur without the program although perhaps at a later point in time.

As part of the market research conducted during the evaluations, participants are asked if they had replaced the furnace earlier that they otherwise would have because of the program, and if so, by how much. This data is used to estimate the “spillover” effect noted in the evaluation, and the 8.7 GJ savings between a standard and a mid efficiency is claimed for the period of the early install.

The 25 year persistence was based upon the average age of the furnace being replaced, as found during the evaluation. It should be noted that for the purposes of this EEC Application, measure life for furnaces was based on the 18 year product life estimate used in the CPR which comes from ASHRAE. ("CPR Residential Sector Report", p62). This shorter estimated life for current furnaces likely reflects the increased complexity of the more efficient products.

7.0 Reference: Exhibit B-2, BCUC IR#1 9.4, Sales of mid and high efficiency furnaces

The response to BCUC IR#1 9.4 from the table for British Columbia appears to indicate that approximate sales in 2005 for mid-efficiency furnaces were 5,000 (113,000 – 108,000) and high efficiency furnaces were 10,000 (94,000 – 84,000) by calculating the change between the balances of housing stock for each kind of furnace. Apparently, twice as many high efficiency furnaces may have been sold than mid-efficiency furnaces.

The response to BCUC IR#1 9.3.1 indicates that the installed incremental cost of a high-efficiency furnace compared to a mid-efficiency furnace is $756 with a simple payback of 7.8 years.

7.1 Are the 5,000 sales of mid-efficiency furnaces and 10,000 sales of high-efficiency furnaces sold in BC in 2005 a reasonable conclusion?

Response:

No, it is not a reasonable conclusion. The data in table 22 provided in our response to BCUC IR#1 9.4 only represents heating system stock in single detached housing and does not represent the total sales of mid and high efficiency furnaces sold in BC in 2005.

Source: NRCan Table 22
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_22_e_2.cfm?attr=0

7.2 In 2005 how many high-efficiency furnace rebates/grants did TGI and TGVI provide to its customers?

Response:

The table below shows the 2005 high-efficiency furnace rebates/grants the Companies offered to customers of TGI and TGVI:

2005 Summary of Terasen Programs - High Efficiency Furnace Rebates

TGI Program Name	Number of Participants
Energy Star Heating System Upgrade Program	3,000
Residential New Construction Heating Program (RNCHP)	750
TGI Total	**3,750**

TGVI Program Name	Number of Participants
Home Builders' Grant	452
H/E Furnace Installation (2004 carry over)	54
Clean Choice*	132
Think Grand	59
Switch & Save	182
TGVI Total	**879**
TGI and TGVI Total	**4,629**

***Note: funding was provided by the provincial government; program, was administered by TGVI**

7.3 Does Terasen have further information (possibly anecdotal) from furnace suppliers on the recent mid-efficiency and high-efficiency furnace sales in the last year or the relative proportion of recent sales for mid-efficiency and high-efficiency furnaces? If so, please elaborate.

Response:

A recent email received July 16, 2008 from Caroline Czajko from the Heating, Refrigeration and Air-Conditioning Institute (HRAI) summarizes manufacturer's data that shows percentage of condensing units (high efficient furnaces) shipped comprised 48% in 2006 and 49% in 2007. Original email gave monthly totals to two significant digits. Total HRAI sales figures are not available to Terasen Gas Inc.

7.4 Please elaborate on why Terasen should continue to offer rebates for a high-efficiency furnace when the payback to the customer is favourable and there is apparent success in high-efficiency furnaces outselling mid-efficiency furnaces?

Response:

As this program is also deigned for the new construction market, the energy savings realized from high-efficiency furnaces is not benefiting the builder or developer. This is also true for the retrofit market where the key decision maker is not the end-user (i.e.

landlords). By offering rebates upfront, Terasen believe changing out of lower efficiency furnace stock to high-efficiency furnaces will be accelerated by incentives along with offsetting the added capital cost of high-efficient furnaces.

8.0 Reference: Exhibit B-2, BCUC IR#1 10.2 and 43.1.2

The response to question 10.2 states that: "The present value of the revenue requirements from the rate base approach is lower for customers assuming customers have a time value of money preference based on a higher discount rate than the utility's after-tax cost of capital."

8.1 Please provide any evidence Terasen has that customers have a time value of money preference based on a higher discount rate than the utility's after-tax cost of capital.

Response:

Numerous studies have been done which suggest that the implicit discount rates employed by energy consumers in assessing energy efficiency investments are quite high - generally in excess of 20%. A summary of the issues associated with these findings is found in Attachment 8.1, a report from the US Energy Information Administration entitled, "U.S. Electric Utility Demand-Side Management: Trends and Analysis" at pages 11 to 13. Footnotes 31 to 40 in this report cite a large number of studies from which these general observations at pages 11 to 13 were drawn. The US EIA report dates to 1996 so the studies cited are from the 1980s and early 1990s. A more recent report (May 28, 2008) by CERA entitled "The Cost of Energy Efficiency Investments: The Leading Edge of Carbon Abatement" confirms that this observation of high implicit discount rates for energy efficiency investments continues to persist to the present. The CERA article states that "(t)ypical consumer implicit discount rates for energy efficiency investments are in the 20 to 30 percent range."

While various factors are thought to contribute to this phenomenon of high implicit discount rates for energy efficiency investments an implication is that there is a clear place for utility investments in energy efficiency programs to achieve government policy objectives and associated economic benefits.

8.2 Please provide a comparison of the cumulative rate impact to customers and the NPV of the rate impact, if an annual expenditure of $1.6 million is made every year for the next 20 years and in one case the annual expenditures are expensed and in the other case the annual expenditures are capitalized and amortized over twenty years as proposed by the Companies. Please use a discount rate equal to TGI's after-tax cost of capital.

Response:

See attachments schedule 8.2a and schedule 8.2b. A summary of the results is provided below. The annual Cost of Service represents the cumulative rate impact for that year and the cost per GJ is set out in line 69 of the respective schedules.

Schedule 8.2a assumes that $1.6 million of EEC expenditures are made every year for 20 years (starting in year 2008) and the annual expenditures are capitalized by way of a regulatory asset deferral account and amortized for 20 years as proposed in the Application. The present value of the Cost of Service under this scenario at the corresponding after tax discount rate is $17.99 million..

Schedule 8.2b assumes that $1.6 million of EEC expenditures are made every year for 20 years (starting from year 2008) and those expenditures are treated as O&M expenses, which are fully recovered at the end of 20 years. The present value of the Cost of Service for 20 years at the corresponding after tax discount rate is $17.90 million.

As can be seen from these results, the NPV for the capitalizing and amortizing scenario is approximately equal to the expensing scenario when discounting at TGI's after-tax cost of capital. (The minor difference is attributable to tax rate changes in the first several years of the analysis).

TERASEN GAS INC. (3 Divisions) **Schedule 8.2a**
DEMAND SIDE MANAGEMENT
$000's

Particulars		**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Current DSM																
Beginning of Year Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization		-	-	-	-											
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EEC																
Beginning of Year Balance		-	1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102
Additions		1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Tax Adjustment		(496)	(480)	(464)	(440)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)
Net Additions		1,104	1,120	1,136	1,160	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184
Amortization		-	(55)	(111)	(168)	(226)	(285)	(344)	(404)	(463)	(522)	(581)	(640)	(700)	(759)	(818)
End of Year Balance		1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102	11,468
Total Deferred DSM																
Beginning of Year Balance		-	1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102
Additions		1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Tax Adjustment		(496)	(480)	(464)	(440)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)
Net Additions		1,104	1,120	1,136	1,160	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184
Amortization		-	(55)	(111)	(168)	(226)	(285)	(344)	(404)	(463)	(522)	(581)	(640)	(700)	(759)	(818)
End of Year Balance		1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102	11,468
Cost of Service																
Operating & Maintenance Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization Expense		-	55	111	168	226	285	344	404	463	522	581	640	700	759	818
Income Tax Expense		7	45	78	106	129	160	190	219	248	276	303	330	356	382	407
Earned Return - Debt		25	73	120	165	208	249	288	324	358	389	417	442	465	486	503
Earned Return - Equity		17	49	81	111	141	169	195	219	242	263	282	299	315	329	341
Earned Return		41	122	200	276	349	418	483	544	600	652	699	742	780	814	844
Total Cost of Service		$ 49	$ 222	$ 390	$ 550	$ 704	$ 863	$ 1,017	$ 1,166	$ 1,310	$ 1,449	$ 1,583	$ 1,712	$ 1,836	$ 1,955	$ 2,069
Volume (TJ/year)		139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	158,554	158,554
Cost $/GJ		$0.0003	$0.0016	$0.0027	$0.0038	$0.0048	$0.0058	$0.0068	$0.0077	$0.0086	$0.0094	$0.0102	$0.0109	$0.0116	$0.0123	$0.0130
Discount Rate		6.095%	6.140%	6.184%	6.251%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%
Present Value COS @ RORB after tax	$ 17,992	$ 46	$ 197	$ 326	$ 431	$ 518	$ 597	$ 662	$ 714	$ 755	$ 785	$ 807	$ 821	$ 828	$ 829	$ 825

Particulars	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Current DSM																
Beginning of Year Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization																
End of Year Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EEC																
Beginning of Year Balance	11,468	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678
Additions	1,600	1,600	1,600	1,600	1,600											
Tax Adjustment	(416)	(416)	(416)	(416)	(416)	-	-	-	-	-	-	-	-	-	-	-
Net Additions	1,184	1,184	1,184	1,184	1,184	-	-	-	-	-	-	-	-	-	-	-
Amortization	(877)	(936)	(996)	(1,055)	(1,114)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)
End of Year Balance	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678	(496)
Total Deferred DSM																
Beginning of Year Balance	11,468	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678
Additions	1,600	1,600	1,600	1,600	1,600	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment	(416)	(416)	(416)	(416)	(416)	-	-	-	-	-	-	-	-	-	-	-
Net Additions	1,184	1,184	1,184	1,184	1,184	-	-	-	-	-	-	-	-	-	-	-
Amortization	(877)	(936)	(996)	(1,055)	(1,114)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)
End of Year Balance	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678	(496)
Cost of Service																
Operating & Maintenance Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization Expense	877	936	996	1,055	1,114	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173
Income Tax Expense	431	455	478	501	523	538	525	513	500	488	475	463	450	438	426	413
Earned Return - Debt	518	531	540	547	552	527	475	423	370	318	266	213	161	109	56	4
Earned Return - Equity	351	359	366	370	373	357	321	286	251	215	180	144	109	74	38	3
Earned Return	869	890	906	918	925	884	796	709	621	533	445	358	270	182	95	7
Total Cost of Service	$ 2,178	$ 2,281	$ 2,380	$ 2,473	$ 2,562	$ 2,595	$ 2,495	$ 2,395	$ 2,294	$ 2,194	$ 2,094	$ 1,994	$ 1,894	$ 1,794	$ 1,693	$ 1,593
Volume (TJ/year)	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554
Cost $/GJ	$0.0137	$0.0144	$0.0150	$0.0156	$0.0162	$0.0164	$0.0157	$0.0151	$0.0145	$0.0138	$0.0132	$0.0126	$0.0119	$0.0113	$0.0107	$0.0100
Discount Rate	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%
Present Value COS @ RORB after tax	$ 817	$ 805	$ 790	$ 772	$ 752	$ 717	$ 648	$ 585	$ 527	$ 474	$ 426	$ 381	$ 341	$ 303	$ 269	$ 238

TERASEN GAS INC. (3 Divisions) **Schedule 8.2b**
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	Total
Current DSM																						
Beginning of Year Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization		-	-	-	-																	
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New EEC																						
Beginning of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Additions																						
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Deferred DSM																						
Beginning of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cost of Service																						
Operating & Maintenance Expense		$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 32,000
Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Tax Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return - Debt		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return - Equity		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Cost of Service		$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 32,000
Volume (TJ/year)		139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	3,057,064
Cost $/GJ		$0.0114	$0.0113	$0.0112	$0.0110	$0.0109	$0.0108	$0.0107	$0.0105	$0.0104	$0.0103	$0.0103	$0.0102	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0105
Discount Rate		6.095%	6.140%	6.184%	6.251%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	6.318%	
Present Value COS @ RORB after tax	$ 17,903	$ 1,508	$ 1,420	$ 1,336	$ 1,255	$ 1,178	$ 1,108	$ 1,042	$ 980	$ 922	$ 867	$ 816	$ 767	$ 721	$ 679	$ 638	$ 600	$ 565	$ 531	$ 500	$ 470	

8.3 Please provide the same comparison as in the immediately preceding question but using a discount rate 1 percent higher than TGI's after-tax cost of capital.

Response:

See attachments schedule 8.3a and schedule 8.3b. A summary of the results is provided below:

Schedule 8.3a assumes that $1.6 million of EEC expenditures are made every year for 20 years (starting in year 2008) and the annual expenditures are capitalized and amortized for 20 years as proposed. The present value of the Cost of Service under this scenario at the corresponding after tax discount rate 1 percent higher than TGI's after-tax cost of capital is $15.58 million.

Schedule 8.3b assumes that $1.6 million of EEC expenditures are made every year for 20 years (starting from year 2008) and those expenditures are treated as O&M expenses, which are fully recovered at the end of 20 years. The present value of the Cost of Service for 20 years at the corresponding after tax discount rate 1 percent higher than TGI's after-tax cost of capital is $16.55 million.

As can be seen from these results, the NPV of the capitalizing and amortizing scenario is lower than the expensing scenario when the discount rate employed is greater than the after-tax cost of capital. If one considers the evidence discussed in the response to IR 8.1 above that consumers implicitly evaluate energy efficiency investments at much higher discount rates the NPV of the capitalizing and amortizing scenario would become much lower than the expensing scenario.

TERASEN GAS INC. (3 Divisions) **Schedule 8.3a**
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	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Current DSM																																
Beginning of Year Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization		-	-	-	-																											
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EEC																																
Beginning of Year Balance		-	1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102	11,468	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678
Additions		1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600											
Tax Adjustment		(496)	(480)	(464)	(440)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	-	-	-	-	-	-	-	-	-	-	-
Net Additions		1,104	1,120	1,136	1,160	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	-	-	-	-	-	-	-	-	-	-	-
Amortization		-	(55)	(111)	(168)	(226)	(285)	(344)	(404)	(463)	(522)	(581)	(640)	(700)	(759)	(818)	(877)	(936)	(996)	(1,055)	(1,114)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)
End of Year Balance		1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102	11,468	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678	(496)
Total Deferred DSM																																
Beginning of Year Balance		-	1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102	11,468	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678
Additions		1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment		(496)	(480)	(464)	(440)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	(416)	-	-	-	-	-	-	-	-	-	-	-
Net Additions		1,104	1,120	1,136	1,160	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	1,184	-	-	-	-	-	-	-	-	-	-	-
Amortization		-	(55)	(111)	(168)	(226)	(285)	(344)	(404)	(463)	(522)	(581)	(640)	(700)	(759)	(818)	(877)	(936)	(996)	(1,055)	(1,114)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)	(1,173)
End of Year Balance		1,104	2,169	3,194	4,186	5,144	6,042	6,882	7,662	8,384	9,046	9,648	10,192	10,676	11,102	11,468	11,774	12,022	12,210	12,340	12,410	11,236	10,063	8,890	7,717	6,544	5,370	4,197	3,024	1,851	678	(496)
Cost of Service																																
Operating & Maintenance Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization Expense		-	55	111	168	226	285	344	404	463	522	581	640	700	759	818	877	936	996	1,055	1,114	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173
Income Tax Expense		7	45	78	106	129	160	190	219	248	276	303	330	356	382	407	431	455	478	501	523	538	525	513	500	488	475	463	450	438	426	413
Earned Return - Debt		25	73	120	165	208	249	288	324	358	389	417	442	465	486	503	518	531	540	547	552	527	475	423	370	318	266	213	161	109	56	4
Earned Return - Equity		17	49	81	111	141	169	195	219	242	263	282	299	315	329	341	351	359	366	370	373	357	321	286	251	215	180	144	109	74	38	3
Earned Return		41	122	200	276	349	418	483	544	600	652	699	742	780	814	844	869	890	906	918	925	884	796	709	621	533	445	358	270	182	95	7
Total Cost of Service		$ 49	$ 222	$ 390	$ 550	$ 704	$ 863	$ 1,017	$ 1,166	$ 1,310	$ 1,449	$ 1,583	$ 1,712	$ 1,836	$ 1,955	$ 2,069	$ 2,178	$ 2,281	$ 2,380	$ 2,473	$ 2,562	$ 2,595	$ 2,495	$ 2,395	$ 2,294	$ 2,194	$ 2,094	$ 1,994	$ 1,894	$ 1,794	$ 1,693	$ 1,593
Volume (TJ/year)		139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554
Cost $/GJ		$0.0003	$0.0016	$0.0027	$0.0038	$0.0048	$0.0058	$0.0068	$0.0077	$0.0086	$0.0094	$0.0102	$0.0109	$0.0116	$0.0123	$0.0130	$0.0137	$0.0144	$0.0150	$0.0156	$0.0162	$0.0164	$0.0157	$0.0151	$0.0145	$0.0138	$0.0132	$0.0126	$0.0119	$0.0113	$0.0107	$0.0100
Discount Rate		7.095%	7.140%	7.184%	7.251%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%
Present Value COS @ RORB after tax	$ 15,581	$ 46	$ 194	$ 317	$ 416	$ 494	$ 565	$ 620	$ 663	$ 694	$ 715	$ 728	$ 734	$ 733	$ 727	$ 717	$ 703	$ 687	$ 667	$ 646	$ 624	$ 589	$ 527	$ 472	$ 421	$ 375	$ 334	$ 296	$ 262	$ 231	$ 204	$ 178

TERASEN GAS INC. (3 Divisions) **Schedule 8.3b**
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**	**Total**
Current DSM																						
Beginning of Year Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization		-	-	-	-																	
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New EEC																						
Beginning of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Additions																						
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Deferred DSM																						
Beginning of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Tax Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
End of Year Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cost of Service																						
Operating & Maintenance Expense		$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 32,000
Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Tax Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return - Debt		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return - Equity		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Earned Return		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Cost of Service		$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 32,000
Volume (TJ/year)		139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	3,057,064
Cost $/GJ		$0.0114	$0.0113	$0.0112	$0.0110	$0.0109	$0.0108	$0.0107	$0.0105	$0.0104	$0.0103	$0.0103	$0.0102	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0105
Discount Rate		7.095%	7.140%	7.184%	7.251%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	7.318%	
Present Value COS @ RORB after tax	$ 16,555	$ 1,494	$ 1,394	$ 1,299	$ 1,209	$ 1,124	$ 1,047	$ 976	$ 909	$ 847	$ 790	$ 736	$ 686	$ 639	$ 595	$ 555	$ 517	$ 482	$ 449	$ 418	$ 390	

8.4 Further to the response to question 43.1.2, please also provide a comparison of the cumulative and NPV of the return to the shareholder under the scenarios outlined in part 1 of this set of questions.

Response:

See attachments below. A summary of the results is provided below.

Schedule 8.4a assumes that $1.6 million of EEC expenditures is made in year 2008 and the annual expenditures are capitalized and amortized for 20 years as proposed. The present value of the return to the shareholder at the corresponding after tax discount rate is $226,000, whereas the NPV of the cost of service is $1,438,000.

Schedule 8.4b assumes that $1.6 million of EEC expenditures is made in year 2008 and the annual expenditures are capitalized and amortized for 3 years. The present value of the return to the shareholder at the corresponding after tax discount rate at $59,000 is lower than that in the 20 year amortization scenario, however the NPV of the cost of service is higher at $1,468,000.

TERASEN GAS INC. **Schedule 8.4a**
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		$ -	$ 1,104	$ 1,049	$ 994	$ 938	$ 883	$ 828	$ 773	$ 718	$ 662	$ 607	$ 552	$ 497	$ 442	$ 386	$ 331	$ 276	$ 221	$ 166	$ 110	$ 55	
Additions		1,600																					
Tax Adjustment		(496)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		1,104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization Expense # of Years	20	-	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	
Closing, Balance		$ 1,104	$ 1,049	$ 994	$ 938	$ 883	$ 828	$ 773	$ 718	$ 662	$ 607	$ 552	$ 497	$ 442	$ 386	$ 331	$ 276	$ 221	$ 166	$ 110	$ 55	$ (0)	
Deferred Charge - mid-year		$ 552	$ 1,076	$ 1,021	$ 966	$ 911	$ 856	$ 800	$ 745	$ 690	$ 635	$ 580	$ 524	$ 469	$ 414	$ 359	$ 304	$ 248	$ 193	$ 138	$ 83	$ 28	
Cost of Service																							
Amortization Expense		$ -	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 1,049
Income Tax Expense		7	38	35	32	29	28	28	27	27	26	26	25	24	24	23	23	22	21	21	20	20	507
Earned Return on Debt		25	48	46	43	41	38	36	33	31	28	26	23	21	18	16	14	11	9	6	4	1	516
Earned Return on Equity		17	32	31	29	27	26	24	22	21	19	17	16	14	12	11	9	7	6	4	2	1	349
Earned Return on Rate Base		41	80	76	72	68	64	60	56	52	47	43	39	35	31	27	23	19	14	10	6	2	865
Total Cost of Service		$ 49	$ 173	$ 167	$ 159	$ 152	$ 148	$ 143	$ 138	$ 134	$ 129	$ 124	$ 119	$ 115	$ 110	$ 105	$ 101	$ 96	$ 91	$ 86	$ 82	$ 77	$ 2,420
Discount Rate @ after tax		6.09%	6.14%	6.18%	6.25%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	
Present Value of Return on Equity @ after tax	$ 226	$ 16	$ 29	$ 26	$ 23	$ 20	$ 18	$ 16	$ 14	$ 12	$ 10	$ 9	$ 8	$ 6	$ 5	$ 4	$ 3	$ 3	$ 2	$ 1	$ 1	$ 0	
Present Value of Cost of Service @ after tax	$ 1,438	$ 46	$ 154	$ 139	$ 125	$ 112	$ 102	$ 93	$ 85	$ 77	$ 70	$ 63	$ 57	$ 52	$ 47	$ 42	$ 38	$ 34	$ 30	$ 27	$ 24	$ 21	

TERASEN GAS INC. **Schedule 8.4b**

RATE BASE / COST OF SERVICE

DEMAND SIDE MANAGEMENT

$000's

Particulars			1 2008	2 2009	3 2010	4 2011	Total
Rate Base - Deferred Charge							
Opening, Balance			$ -	$ 1,104	$ 736	$ 368	
Additions			1,600				
Tax Adjustment			(496)	-	-	-	
Net Additions			1,104	-	-	-	
Amortization Expense # of Years		3	-	(368)	(368)	(368)	
Closing, Balance			$ 1,104	$ 736	$ 368	$ -	
Deferred Charge - mid-year			$ 552	$ 920	$ 552	$ 184	
Cost of Service							
Amortization Expense			$ -	$ 368	$ 368	$ 368	$ 1,104
Income Tax Expense			7	170	157	142	476
Earned Return on Debt			25	41	25	8	98
Earned Return on Equity			17	28	17	6	67
Earned Return on Rate Base			41	69	41	14	165
Total Cost of Service			$ 49	$ 606	$ 566	$ 523	$ 1,745
Discount Rate @ after tax			6.09%	6.14%	6.18%	6.25%	
Present Value of Return on Equity @ after tax	$ 59		$ 16	$ 25	$ 14	$ 4	
Present Value of Cost of Service @ after tax	$ 1,468		$ 46	$ 538	$ 473	$ 411	

9.0 Reference: Exhibit B-2, BCUC IR#1 13.1, and BC Energy Plan, Policy Action #10

9.1 The real and nominal prices in the table are exactly the same throughout. Please confirm whether this is in error and if so provide a corrected table. If a corrected table is provided, please state what year the dollars of the real prices are stated in.

Response:

The real dollars are for the year 2007.

The model provides a deflator variable to convert nominal to real dollars, if necessary. The deflator is set at 1.00 because the input prices were in real dollars. For purposes of the runs performed, Rows 7 and 9 of the Input Sheet could be deleted.

9.2 Are the price figures in the response to IR#1 13.1 premised on British Columbia remaining a net exporter of natural gas for the years listed?

Response:

The basis for the prices are based on forward market prices applicable to each region on a macro level which takes into consideration the overall supply and demand picture applicable to that region as well as North American supply/demand fundamentals. Therefore, the figures are not premised on BC remaining a net exporter of natural gas.

9.3 Please provide the natural gas price forecast that forms the basis for the response to IR#1 13.1, along with the high and low forecasts for the same time period.

Response:

Below is the annual AECO price forecast strip that was used as the basis for the response to IR#1 13.1. The forecast was based on GLJ Petroleum Consultants January 1, 2006 AECO-C Then Current price forecast in $Cdn/MMbtu. An inflation factor of 2% was assumed for prices beyond 2020. Terasen Gas forecasted midstream costs, like transportation and storage costs, were then added onto this price forecast via the Sendout model. There were no high or low forecasts used for the table in 13.1.

Year	AECO Price Forecast ($Cdn/MMBtu)
2008	$ 8.00
2009	$ 7.50
2010	$ 7.20
2011	$ 6.90
2012	$ 6.90
2013	$ 7.05
2014	$ 7.20
2015	$ 7.40
2016	$ 7.55
2017	$ 7.70
2018	$ 7.86
2019	$ 8.01
2020	$ 8.17

The Sendout model is one of the tools that Terasen employs for these types of forecasting. Another method that Terasen uses frequently for forecasting such data is by taking the forward price strip at a given time and adding to that a midstream charge to ensure gas delivery to the various points on the Companies' transmission system. These midstream charges would include charges for leasing storage facilities and holding firm transportation contracts on third party pipelines that deliver gas to Companies' market area over the course of the year.

10.0 Reference: Exhibit B-2, BCUC IR#1 1.1 and 14.1, and Attachment 1.1, and Exhibit B-1, Tables 7.1.2.2 and 7.1.2.3

10.1 What reductions in Residential consumption would be realised if Terasen increased natural gas rates by the amounts shown in Tables 7.1.2.2 and 7.1.2.3, Line 34?

Response:

The table below illustrates the reductions in Lower Mainland Residential consumption that are estimated to be realized if Terasen increased natural gas rates by the amounts shown in Tables 7.1.2.2 and 7.1.2.3. These estimates are based purely on mathematical calculations incorporating the estimated price elasticity for residential customers. There are many factors affecting consumption, such as appliance retrofit activity, changes in housing mix, government policies, public perceptions, and also non-recurring and unpredictable events such as the California Energy Crisis and Hurricane Katrina. These factors all create “noise” in the consumption data, which leads to uncertainty when estimating the demand response to changes only in price (i.e. Price Elasticity). This is the main reason, as stated in Terasen Utilities’ response to BCUC IR 1.14.2, Terasen does not incorporate price elasticity into its demand forecasts.

The estimated variable charges for TGI (the Lower Mainland region is used as a proxy for TGI) seen below represent the sum of the delivery, commodity cost recovery, and midstream cost recovery charges together with Rate Riders 3, 4, 5, and 8, effective July 2008. For TGVI, the estimated variable charge includes the Commodity Rate effective April 1, 2008. The costs per GJ from table 7.1.2.2 or 7.1.2.3 are also added to the variable charges to estimate the annual changes. It is assumed that no other increases to rates occur. Following is a breakdown of the variable charges for TGI and TGVI:

TGI (LML) Tariffs effective July 1, 2008 TGVI Tariffs effective April 1, 2008

TGI Delivery Charge	2.783
Commodity Cost Recovery Charge	9.78
Midstream Cost Recovery Charge	1.209
Rate Rider 3	-0.127
Rate Rider 4	-0.022
Rate Rider 5	0.094
Rate Rider 8	0.117
Total TGI Variable Charges	**13.834**
TGVI Commodity Rate	14.325
Total TGVI Variable Charges	**14.325**

TGI 2007 Normalized Actual Residential Demand = 70,638 TJ
TGVI 2007 Normalized Actual Residential Demand = 4,575 TJ

In the table below, change in variable charge is simply the percentage change in the estimated variable charge from the previous year to the current year.

The estimated change in demand is determined by applying the Residential price elasticity to the estimated change in the variable charge.

Estimated Change in Demand = Estimated Change in Variable Charge X Price Elasticity

The estimated change in demand is then applied to the 2007 normalized actual demand, which then allows for the determination of the future annual demand and year over year change in demand.

Estimated Consumption Reduction – Table 7.1.2.2

Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Cost $/GJ from Table 7.1.2.2	0.023	0.0281	0.027	0.032	0.0306	0.0293
Estimated Variable Charge ($)	13.857	13.8851	13.9121	13.9441	13.9747	14.004
Change in Variable Charge (%)	0.17%	0.20%	0.19%	0.23%	0.22%	0.21%
Estimated Change in Demand (%)	-0.03%	-0.04%	-0.04%	-0.05%	-0.05%	-0.04%
Estimated Demand (TJ)	70,613	70,583	70,554	70,520	70,488	70,457
Estimated Change in Demand (TJ)	-25	-30	-29	-34	-32	-31

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Cost $/GJ from Table 7.1.2.2	0.0281	0.0269	0.0258	0.0247	0.0236	0.0226	0.0216
Estimated Variable Charge ($)	14.0321	14.059	14.0848	14.1095	14.1331	14.1557	14.1773
Change in Variable Charge (%)	0.20%	0.19%	0.18%	0.18%	0.17%	0.16%	0.15%
Estimated Change in Demand (%)	-0.04%	-0.04%	-0.04%	-0.04%	-0.04%	-0.03%	-0.03%
Estimated Demand (TJ)	70,427	70,399	70,372	70,346	70,321	70,297	70,275
Estimated Change in Demand (TJ)	-30	-28	-27	-26	-25	-24	-23

Estimated Consumption Reduction – Table 7.1.2.3

Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Cost $/GJ from Table 7.1.2.3	0.0702	0.0656	0.0489	0.0684	0.0643	0.0607
Estimated Variable Charge ($)	14.3952	14.4608	14.5097	14.5781	14.6424	14.7031
Change in Variable Charge (%)	0.49%	0.46%	0.34%	0.47%	0.44%	0.41%
Estimated Change in Demand (%)	-0.10%	-0.10%	-0.07%	-0.10%	-0.09%	-0.09%
Estimated Demand (TJ)	4,570	4,566	4,563	4,558	4,554	4,550
Estimated Change in Demand (TJ)	-5	-4	-3	-5	-4	-4

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Cost $/GJ from Table 7.1.2.3	0.0575	0.0544	0.0516	0.0489	0.0464	0.044	0.0418
Estimated Variable Charge ($)	14.7606	14.815	14.8666	14.9155	14.9619	15.0059	15.0477
Change in Variable Charge (%)	0.39%	0.37%	0.35%	0.33%	0.31%	0.29%	0.28%
Estimated Change in Demand (%)	-0.08%	-0.08%	-0.07%	-0.07%	-0.07%	-0.06%	-0.06%
Estimated Demand (TJ)	4,546	4,543	4,539	4,536	4,533	4,530	4,528
Estimated Change in Demand (TJ)	-4	-4	-3	-3	-3	-3	-3

10.2 How would those compare to the expected Residential consumption reductions shown in Exhibit B-2, Attachment 1.1?

<u>Response:</u>

The following tables compare the estimated Lower Mainland Residential consumption reductions to those shown in Exhibit B-2, Attachment 1.1:

The Total TGI/TGVI Residential Savings – EE is the total savings expected as a result of the TGI/TGVI Residential Energy Efficiency programs (taken from Exhibit B-2, Attachment 1.1).

The estimated change in demand figures are from the tables calculated in the previous question.

Estimated Consumption Reduction Compared – Table 7.1.2.2

Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Total TGI Residential Savings - EE (TJ)	-94	-211	-300	-300	-300	-300
Estimated Change in Demand (TJ)	-25	-30	-29	-34	-32	-31
Change in Demand / Total EE Savings (%)	26%	14%	10%	11%	11%	10%

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total TGI Residential Savings - EE (TJ)	-300	-300	-300	-300	-300	-300	-300
Estimated Change in Demand (TJ)	-30	-28	-27	-26	-25	-24	-23
Change in Demand / Total EE Savings (%)	10%	9%	9%	9%	8%	8%	8%

Estimated Consumption Reduction Compared – Table 7.1.2.3

Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Total TGVI Residential Savings - EE (TJ)	-4	-12	-24	-24	-24	-24
Estimated Change in Demand (TJ)	-5	-4	-3	-5	-4	-4
Change in Demand / Total EE Savings (%)	116%	37%	14%	19%	18%	17%

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total TGVI Residential Savings - EE (TJ)	-24	-24	-24	-24	-24	-24	-24
Estimated Change in Demand (TJ)	-4	-4	-3	-3	-3	-3	-3
Change in Demand / Total EE Savings (%)	16%	15%	14%	13%	12%	12%	11%

Overall, the change in demand due to response in price increases is very small. In 2008, for example, the total estimated change in demand due to price response is a decrease of 30 TJ, representing only 0.04% of total residential estimated demand for the Companies' in 2008.

11.0 Reference: Exhibit B-2, BCUC IR#1 14.2, Price Elasticity

The response to BCUC IR#1 14.2 indicates the price elasticity for residential customers is 21% and for commercial customers is 17%.

11.1 If TGI revenue requirements increased by $10.0 million and it caused a corresponding increase in delivery rates, assuming a price elasticity of demand for residential customers at 21% and commercial customers at 17%, what would be the total corresponding change in consumption volumes in GJ? Please show the calculations.

Response:

Assuming all else equal, and that the gross margin is allocated to all customer classes, an increase in revenue requirements by $10.0 million is estimated to result in an increase of 2.01% to all delivery rates:

	$000's
(1) Revenue Requirement Change	10,000
(2) Existing Approved Margin	497,314 (2008 Approved Gross Margin)

% Change to delivery rates = (1)/(2) = 2.01%

For residential customers, given a price elasticity of 21% and assuming all else being equal, this would result in an estimated decline in consumption of 2.01 X 0.21 = 0.42%.

For commercial customers, given a price elasticity of 17% and assuming all else being equal, this would result in an estimated decline in consumption of 2.01 X 0.17 = 0.34%.

Therefore, given an increase in revenue requirements of $10.0 million, Terasen would estimate a resulting decline in consumption volumes of 0.42% in residential consumption and 0.34% in commercial consumption. Note the estimated reductions are based upon price elasticities only, and as per the response to BCUC IR1 14.2 Terasen would not recommend incorporating these figures into its demand forecasts.

12.0 Reference: Exhibit B-2, BCUC IR#1 15.2.3

The Companies' response to question 15.2.3 states that "It is the Companies' view that consumers will still want to buy fireplaces, even in a carbon-constrained world, and that the Terasen Utilities should encourage the use of the most efficient gas appliances available."

12.1 Can the companies confirm that an incentive to purchase efficient gas fireplaces may not only encourage some customers to purchase an efficient gas fireplace rather than an inefficient gas fireplace, but also to encourage some customers to purchase an efficient gas fireplace rather than no fireplace at all? If so, does this make the efficient gas fireplace program, in part, a load building program? If not, why not?

Response:

No, the efficient gas fireplace programs outlined are not load-building programs. Please see Table 6.3.1 on page 58 of Exhibit B-1, the Application. In the case of new construction, the Enerchoice Fireplace Program is planned to be aimed at builders and developers. The goal of the program for new construction is to ensure the builder or developer who has already designed a home to include a gas fireplace is incented to select the most efficient fireplace available. In the case of retrofits, the program is aimed at customers who are replacing an existing gas hearth product, for example a logset (which has no heating value and is entirely decorative), with an Enerchoice rated fireplace.

12.2 Can the companies confirm that a regulation, restricting the market to only efficient gas fireplaces, would have purely a conservation effect? If not, why not?

Response:

Confirmed.

13.0 Reference: Exhibit B-2, BCUC IR#1 16.2

13.1 With respect to the Table on page 39 and note 1 on page 40, please confirm that the revised table calculates the DSM per customer based on the total DSM budget of $279 million for both gas and electric initiatives and the number of gas customers.

Response:

That is correct; $279 million is PG&E DSM budget for both gas and electric DSM initiatives in 2007. The DSM per customer is based on the total DSM budget and the number of gas customers.

The Companies chose to use $279 million as the total number for DSM budget as some electric customers can also be natural gas customers. Including both the number of natural gas customers and the number of electric customers in the calculation could lead to double counting.**)**

13.2 Further please confirm that if the percentage of the DSM budget allocated to the natural gas line of business is used (14 percent of the total, per note 1), the DSM per customer falls to $9.3/customer.

Response:

That is correct, $9.3/customer assuming P&G's DSM budget for natural gas is based on 14% of 279 million.

14.0 Reference: Exhibit B-2, BCUC IR#1 24.4

The Companies state that one potential reason for the gain in participation in the Energy Star Heating Upgrade Program is an increase in general awareness about energy, costs, and the value of conservation.

14.1 What is the current proportion of Energy Star furnaces being sold (irrespective of program participation) relative to standard or mid-efficiency furnaces?

Response:

In order to qualify for an Energy Star rating a furnace must be 90% efficient (condensing technology). A recent email received July 16, 2008 from Caroline Czajko from the Heating, Refrigeration and Air-Conditioning Institute (HRAI) summarizes manufacturer's data that shows percentage of condensing units (high efficient furnaces) shipped comprised 48% in 2006 and 49% in 2007. Original email gave monthly totals to two significant digits. Total HRAI sales figures are not available directly to Terasen Gas Inc.

14.2 Are Terasen rebates for high-efficiency appliances available year-round or only on a seasonal basis? If they are not available throughout the year, why not?

Response:

Currently, the rebates offered by the Companies for high efficient appliances are not available year-round as current DSM funding is insufficient for year round rebates. The Companies are proposing with this Application to put programs into the marketplace that run until the funding envelope expires – December 31, 2010.

15.0 Reference: Exhibit B-2, BCUC IR#1 26.1, and BC Energy Plan, Policy Action #1

15.1 If the electric-gas fuel substitution measures proposed in the Application are approved and are successful, what proportion of BC Hydro's incremental resource needs does Terasen believe that the measures proposed in the Application can be achieved by 2020?

Response:

Table 7.2 on page 99 of the EEC Application identifies the present value of the expected electricity savings from fuel switching are 550,000 MWh (550 GWh) over the life of the proposed measures for the implementation over the 2008-2010 timeframe. BC Hydro's 2008 LTAP identified a projected energy shortfall of 14,000 GWh in F2020.

15.2 Would the achievement of that proportion be possible given Terasen's existing transmission, storage, and distribution assets?

Response:

Given the relatively small increase in load of 2.28 million GJ (550,000 MWh) over the life of the measures proposed as identified in Table 7.2 on page 99 of the EEC application, it is unlikely that Terasen would be constrained by its current transmission, storage or distribution assets. This is in contrast to BC Hydro who has identified in their 2008 LTAP significant energy and transmission capacity shortfalls that would be exacerbated significantly if more electric load for heating were to begin displacing natural gas.

Further, load decreases from other energy efficiency and conservation programs included in the EEC application will offset load increases that result from electric to natural gas fuel switching programs. Fuel switching programs should not be considered in isolation of other EEC programs as collectively these programs will improve the efficiency of Terasen Gas transmission and distribution systems making better use of these energy transportation assets.

16.0 Reference: Exhibit B-2, BCUC IR#1 32.3 and 33.3

The Application states that the $500,000 for Trade relations includes the cost of a staff member plus the activities outlined on pages 68 and 69 of the Application. The activities outlined on page 68 and 69 of the Application appear to identify the activities of such a staff member, but the Companies do not identify the incremental cost associated with those activities. The response to question 33.3 identifies the fully loaded cost of a staff member in the Innovative Technologies, NGV and Measurement area as approximately $100,000.

16.1 Is that estimate reasonable for the fully loaded cost of the Trade Relations staff member as well? If not, please provide an estimate and the reasons for the difference.

Response:

Yes.

17.0 Reference: Exhibit B-2, BCUC IR#1 33.5

The Companies propose that the Commission approve an overall expenditure by utility rather than approving funding by program area or individual program initiative. To ensure that programs developed have value for ratepayers, the Companies propose to report on EEC activity yearly and to engage an EEC Stakeholder group; "…one of the roles for that group would be to ensure that programs that are developed have value for ratepayers."

17.1 Please describe in detail the authority the Stakeholder group would have to direct Terasen to amend or terminate unproductive programs.

Response:

The Companies are proposing that they hold an annual workshop for Stakeholders at which the previous year's activities and results, and activities and results for the upcoming year would be presented and discussed. It is the Companies' intent to engage in a consultative process with stakeholders, rather than one in which stakeholders feel the need to direct the Companies one way or another. It is the Companies' view that it is in the Companies' best interest to take it upon themselves to amend or terminate unproductive programs, defined as those that would bring the overall portfolio TRC down below 1.0. It is the Companies' intent to monitor the portfolio TRC on a monthly basis. Further, the Companies intend to bring forward an Application for EEC funding beyond 2010, and in order to be successful in obtaining funding approval for future EEC activity, the Companies will need to be able to prove that the funding being requested in the current Application has not been spent on unproductive programs, so it is again in the Companies' best interest take it upon themselves to amend or terminate unproductive programs.

18.0 Reference: Exhibit B-2, BCUC IR#1 37.3, and Terasen Thermal Metering Annual Report, 2007/08, p. 2

18.1 The 2007/08 Thermal Metering Report describes the first pilot project for the program. It states that the developer decided not to go with a hydronic heating system due to project costs exceeding budget.

Can Terasen confirm that the reference to project costs in the report refers to overall project costs for the development rather than the costs related specifically to the hydronic heating system?

Response:

It is the Terasen Utilities' understanding that the developer's Heating, Ventilating, and Air Conditioning ("HVAC") costs, which included hydronic heating costs, were forecast to be too high and would result in project costs exceeding budget. As such the developer chose an alternate HVAC solution.

19.0 Reference: Exhibit B-1, Section 6.13. Portfolio Approach to EEC Programs, and Alignment of Program Cost/Benefit Analysis Practices Across the Terasen Utilities,pp. 82-83

Page 83 of the Application states: “The energy efficiency and fuel switching programs would be planned and evaluated on the TRC, the RIM test, the Utility Cost (“UC”) test and the Participant test, and the overall portfolio TRC test results would have to be greater than 1.0 to proceed.”

19.1 What would be the thresholds for the scores on the RIM test, UC test and the Participant test for an individual program not to proceed? If an activity had a relatively low RIM test, UC test and Participant test but a favourable TRC, would that be sufficient to proceed? Please explain.

Response:

The Companies are not proposing any thresholds with respect to the RIM test, the UC test and the Participant test. In the absence of such thresholds, the Companies are not comfortable stating that an activity would proceed or not based on RIM, UC and Participant test results. The Companies are proposing instead that the overall portfolio level TRC must be maintained at 1.0 or greater. It is the Companies’ view, shared by other jurisdictions, that the TRC test is the most appropriate test for programs. Please see pages 5 and 6 of the Attachment filed in response to BCUC IR 1.84.1, “A DSM Handbook for Ontario Natural Gas Distribution Companies”, which states on page 6:

> *“The TRC test is the sole test of cost effectiveness for programs and will be used for screening the portfolio of programs. The utilities will ensure that the total portfolio has a positive net TRC. The utilities may reserve the right to invest in individual technology or program offerings that do not have a positive net TRC, if the utility believes there are compelling reasons to do so.”*

20.0 Reference: Exhibit B-2, BCUC IR#1 41.1 and 41.2, Spreadsheet for proposed amortization

20.1 The spreadsheet for the responses to BCUC IR#1 questions 41.1 and 41.2 does not appear to be in the referred Attachment to BCUC IR#1 41.1. Please file the 20 year model.

Response:

Attachment 20.1 contains the 20 year model.

21.0 Reference: Exhibit B-2, BCUC IR#1 41.3, Intergenerational Equity

The response to BCUC IR#1 41.3 states:

> "The Companies do not believe that there would be any intergenerational inequity created for future customers by contributing to the recovery of DSM expenditures as proposed in this Application. On the contrary, intergenerational inequity is more likely to be a concern if DSM expenditures were expensed in the year incurred…"

21.1 If a new customer with a new house connects to the natural gas system in 2015, would the new customer's rates include the amortized cost of past accumulated DSM expenditures of which the new customer does not receive any benefit?

Response:

A new customer with a new house who connects to the natural gas system in 2015 would pay a rate that includes the amortized cost of past accumulated DSM expenditures. However, Terasen Gas disagrees with the implication in the question that the customer does not receive any benefit from the past DSM expenditures. Past DSM expenditures help support the efficient use of both on system and off-system assets through the reduction in use rates. These efficiencies help reduce the overall cost of service for current and future customers through the avoidance or deferral of capital expansion and midstream contracts/assets.

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.

22.0 Reference: Exhibit B-2, BCUC IR#1 42.1 and Attachment 40.2

Terasen's response to question 42.1 states that "The Terasen Utilities are proposing an amortization period of 20 years, based on a weighted average of the proposed measure lives. (It should be noted that the range of measure lives outlined in the Application range from 13 to 25 years)."

22.1 Attachment 40.2 shows that some programs have a Measure Life of 10 years. Please confirm that the response to question 42.1 should have stated that the range of measure lives is "…from 10 to 25 years." If not, please explain why 13 years is appropriate.

Response:

That is correct – the response to BCUC IR 1.42.1 should have stated that the range of measure lives is from 10 to 25 years.

22.2 Is the estimate of the measure life in the Application the same as the expected equipment life? If so, please explain the basis for the estimate of the expected equipment life. If not, please explain how the measure life is different that the expected equipment life, and what adjustments were made to the expected equipment life to estimate the measure life.

Response:

For most programs, the measure life is taken to be the same as the expected equipment life. The two possible exceptions are the Commercial BAS program and the Building Recommissioning Programs where the measure life is assumed to be 10 years. In these two programs, some equipment may be changed, but the savings accrue from changes in the operations of the facilities. All estimates for expected equipment life were derived from the Conservation Potential Review, and sources are typically noted in that report.

22.3 Would Terasen agree that the economic life of a piece of equipment may be significantly shorter than its useful life? If not, why not?

Response:

The issue of economic life being shorter than the useful life relates to the possibility that the equipment (for which an incentive has been paid) may be discarded before the program achieves the expected energy savings. This is often a concern with industrial programs where plants may be shut down or even sold and the equipment moved to other countries and the benefit lost to the program. It is a lesser concern in the commercial sector, but still a concern where tenants change and the use of space changes. For example when office space is reconfigured, some lighting may be discarded or replaced with a different technology. In the residential sector, it is not considered to be a significant issue.

However, this would appear to be more of an issue for electrical equipment (and programs) than for natural gas. The major uses of natural gas revolve around space and water heating and due to the high cost and inconvenience of doing so, it is less likely that this equipment would be discarded. This contrasts to many electrical measures such as lighting or appliances, where it is less costly or inconvenient to revert back to the less efficient technology

23.0 Reference: Exhibit B-2, BCUC IR#1 42.2

The response to BCUC IR#1 42.2 states:

> "The Companies propose that should the Application be approved as outlined, expenditures associated with cancelled programs would be treated the same as other expenditures in order to reduce the administrative burden and would be amortized over 20 years."

23.1 Please explain further why the Companies should earn a return through rate base on cancelled program costs that have no future benefit.

Response:

The Companies have put forth in Section 5 (Program Principles) of the Application that the Total Resource Cost/Benefit ("TRC") of the portfolio over the funding period will have a ratio of 1 or higher. Cancelled program costs are taken into account in the TRC analysis. It is the Companies position that EEC expenditures and results need to be looked at on a portfolio basis and not at an individual programs level. Thus, if the TRC is greater than one on a portfolio basis there are future benefits to customers, which is why the Companies should earn a return on cancelled program costs.

23.2 If either TGI or TGVI incurs expenses of $1 million to undertake an energy efficiency program and the program results in no savings, what are the financial impacts resulting from this treatment of the costs on:

(a) Rate base

Response:

The Companies assume that the savings alluded to in the question is energy savings (benefit) for the customer. There will be no difference to rate base, shareholder earnings, or customers' rates under a scenario where the program results in no benefit to the customer as compared to a scenario where the customer realizes benefits. However, the example in the question ignores the fact that the Companies are proposing that the total portfolio of EEC expenditures/programs require a TRC of greater than 1.0, i.e., there will be benefits realized by customers. The Companies are not anticipating undertaking any programs that would result in no benefits to customers, accordingly, the hypothetical scenario posed in the question has little relevance.

(b) Terasen and its shareholders

Response:

Please refer to the response to BCUC IR 2.23.2 (a) above.

(c) TGI or TGVI customers

Response:

Please refer to the response to BCUC IR 2.23.2 (a) above.

23.3 If a Shared Savings Program similar to that used in Ontario (and discussed in Terasen's response to IR#1 43.2.4.6) was in place for the Companies and either TGI or TGVI incurs expenses of $1 million to undertake an energy efficiency program and the program results in no savings, what are the financial impacts resulting from this treatment of the costs on:

(d) Rate base

Response:

Based on the interpretation of Shared Savings Program as discussed in Terasen's response to IR No.1- 43.2.4.6, the Companies assume there would be no impact on rate base as the expenditures are expensed and recovered from customer through rates whether the program is successful or not.

(e) Terasen and its shareholders

Response:

Based on the interpretation of Shared Savings Program as discussed in the Terasen Utilities' response to BCUC IR 1.43.2.4.6, the Companies believe that there would be no earnings accruing to the shareholder for the particular program under such a hypothetical scenario. The Companies are of the view, as discussed in more detail in the response to BCUC IR 2.29.1, that the Shared Savings Program is not appropriate for utilities in British Columbia as it is inconsistent with the Section 60 (b) (ii) of the Utilities Commission *Act*.

(f) TGI or TGVI customers

Response:

Based on the interpretation of Shared Savings Program as discussed in the Terasen Utilities' response to BCUC IR 1.43.2.4.6, the Companies believe that customer's rates would be lower under a scenario where the program delivered no customer benefits, as opposed to what they would have been if the program delivered benefits in excess of expectations.

24.0 Reference: Exhibit B-1, Appendix 4, DSM Activity of Other Utilities, pp. 15-19; Exhibit B-2, BCUC IR#1 43.2.4, Ontario Utilities Regulatory Environment

The Application in Appendix 4, page 15 with regard to Enbridge Gas Distribution and Union Gas states: “For both utilities, all DSM costs are recovered through the rate base.”

The response to BCUC IR#1 43.2.4.2 states in regards to Union Gas and Enbridge Gas Distribution:

> “Both include costs in their rate base, but do not capitalize the expenditure. Uses a Variance Account to reconcile expenditure and revenue at the end of each financial year; neither company earns on the DSM revenue but rather through the SSM mechanism.”

On September 1, 2007 Union Gas filed an update to its “Multi-Year Incentive Rate Regulation for Natural Gas Utilities EB-2007-0606” by updating Exhibit D.

In the Union Gas Exhibit D, Tab 1, page 3 of 10 it states:

> *Treatment of Demand Side Management (“DSM”) Costs*
>
> In accordance with the Board’s EB-2006-0021 Decision, Union will increase its 2007 DSM budget by 10% per year for each of 2008 and 2009 to $18.7 million and $20.6 million, respectively. Union is proposing to treat the costs associated with DSM as a Y-factor. Accordingly, Union will remove the DSM costs currently in rates by rate class prior to applying the price cap index. After the price cap adjustment has been determined, Union will add back the DSM costs by rate class plus 10%. The result is that the increase in the 2008 and 2009 DSM budgets will be allocated in proportion to how the 2007 DSM budget was included in rates. Consistent with the Board’s EB-2007-0598 Decision, Union will true-up for differences between the DSM costs included in rates and the actual amount spent on DSM programs on a rate class basis as part of the disposition of the DSMVA.

The Union Gas Exhibit D, Tab 3, Schedules 1 to 3 pages appears to indicate that the $17.0 million of DSM expenditures are removed from rates and then $18.7 million is then added back into the 2008 rates.

24.1 Please confirm that Union Gas currently expenses DSM costs fully into 2008 rates ($18.7 million of 2008 DSM expenditures).

Response:

Yes, that is correct. Union Gas Exhibit D, Tab 1, page 3 of 10 mentioned above forms part of the Union Gas’ rate adjustment application to the OEB. This application dealt with, among other issues, the establishment of an incentive mechanism. To establish the rate base upon which the incentive mechanism was to be calculated, various flow-through expenditures (including the $17 million of DSM expenditure for 2007) were excluded from the 2007 rate base calculation. In 2008, $18.7 million (as approved in EB-2006-0021) were added back into the rates. This increase reflects the budget permissible under EB-2006-0021 Board Decision[6]:

- the 2007 budget will be $17.0 million;
- budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively

Note that EGD also filed a similar application in 2006 and received a EB-2007-0615 Board Decision[7]. In establishing incentive mechanism a similar process was followed:

> *Row 5 removes the 2007 Board Approved DSM operating costs of $22.0 million as established within the EB-2006-0021 Decision. This adjustment is necessary as the 2008 DSM operating cost budget has already been approved in the above mentioned proceeding, therefore the base distribution revenue upon which the incentive escalation formula can be applied needs to exclude the 2007 approved amounts. The 2008 Board Approved DSM operating costs, outside of the incentive escalation formula, are included into the 2008 total revenue at row 21.*

24.1.1 If so, does Enbridge Gas Distribution also fully expense its DSM expenditures into rates similar to Union Gas?

Response:

The treatment of DSM expenditures for both Union Gas and EGD is governed by OEB Decision EB-2006-0021[8] which addresses a number of DSM issues across natural gas utilities in Ontario. Both Union Gas and EGD are regulated under OEB and therefore must adhere to the rules of this decision. As confirmed by Judith Ramsay of Enbridge Gas Distribution, EGD fully expenses its DSM expenditures into rates in a similar manner to Union Gas.

6 http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf; p. 23
7 http://www.oeb.gov.on.ca/documents/cases/EB-2007-0615/dec_union_enbridge_20080211.pdf p.48
8 http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf

25.0 Reference: Exhibit B-2, Response to BCUC IR#1 43.2.4.3
DSM Amortization – Nevada Administrative Code

The Terasen Utilities response to BCUC IR#1 43.2.4.3 states: "Similarly, the Nevada Administrative Code, NAC 704.9523, charges the Public Utility Commission with determining an amortization period that is "consistent with the life of the investment.""

Adopted Regulation of the Public Utilities Commission of Nevada in LCB File No. R162-07, effective June 17, 2008, in Sec. 2 states "NAC 74.9523 is hereby amended to read as follows:" then for 3(e) (1) it states:

> (1) The Commission will adjust the rate to amortize the balance over a *3-year* period ~~[determined]~~ *, unless otherwise specified* by the Commission . ~~[to be appropriate for clearing the account and consistent with the life of the investment.]~~

Source: http://www.leg.state.nv.us/register/RegsReviewed/$R162-07A.pdf

25.1 Please confirm that the Public Utilities Commission of Nevada presently amortizes DSM expenditure balances over a 3 year period. If not, what is the amortization period for DSM expenditures?

Response:

Nevada uses a three-year amortization period for DSM and according to a source at Nevada Power; this is the standard amortization period for DSM. This is confirmed in Docket 07-06029 (see Attachment 25.1) of the Nevada Public Commission that amended the pertinent regulations in the Nevada Administrative Code.

Page 5 of Attachment 1 to the order, states the following: "the Commission will adjust the rate to amortize the balance over a three-year period, unless otherwise specified by the Commission."[9] In order to recover DSM costs, Nevada is required to record their costs for each DSM program in a separate sub account of Account 182.3 (other Regulatory Assets). As a component of an application by the utility to change general rates, any accumulated balance in the sub account has to be cleared. The Commission adjusts the rates to amortize the balance over 3 years. Nevada is required to begin amortizing costs on the date that the change in general rate becomes effective.

[9] Docket 07-06029, Attachment 1, p. 5

25.2 From the research conducted by the Terasen Utilities are there other jurisdictions that allow utilities to amortize DSM balances over the life of the investment? If so, please provide the information.

Response:

Please refer to the Companies' response to BCUC IR 1. 43.2.4.3.

From the research conducted by the Terasen Utilities, the following jurisdictions allow utilities to amortize DSM balances over the life of the investment:

Manitoba

Manitoba Hydro

As noted in the "2007/08 & 2008/09 General Rate Application, Response to Information Requests of the Public Utilities Board of Manitoba":

> *"A 15 year amortization period has been selected for DSM as it is representative of the long term value provided through DSM programs."*[10]

British Columbia

BC Hydro

As noted in "BC Hydro Revenue Requirement", Volume 1 of 3:

> *"Costs are capitalized and amortized to appropriately match the costs with energy savings benefits over future years, not to exceed ten years."*[11]

FortisBC

As noted in "G-58-06 – Negotiated Settlement Agreement", Appendix 1, p. 9 – 10, line 15, Amortization of Demand Side Management Expenditures (see Attachment 25.2):

> *"The Company proposes to change the amortization period for its DSM expenditures from 8 years to 10 years in aggregate, based on a weighted amortization of individual program lives (Exhibit B-1, Tab 5, page 61 and Tab 10 Appendix C). Individual programs have lives ranging from 5 to 30 years, with a weighted amortization period of 11 years."*

One of the reasons the Companies requesting to amortize DSM balances over the life of the investment is because natural gas utilities DSM programs have longer benefits to customer because natural gas equipment tends to last longer compared to electrical equipment (furnaces vs. CFLs). This issue has been discussed at length during the first round of IRs from BCUC (refer to 10.2, 41.10, 43.1.2, 43.2.1, etc).

---

[10] http://www.hydro.mb.ca/regulatory_affairs/gas/pubgasfiling2007/responses_to_pub_irs.pdf p. 259

[11] http://www.bchydro.com/rx_files/info/info45426.pdf, Page 461 (section 8-70)

26.0 Reference: Exhibit B-2, BCUC IR#1 43.2.4.4, Public Purpose Funds

26.1 Please explain whether in the Companies' view, it would be more efficient in British Columbia to have DSM programs administered by one body, rather than three or four separate utilities each potentially with significant DSM programs.

Response:

In addition to the response below, please see the responses to BCUC IR 1.43.2.4.4 and 43.2.4.5.

The Companies believe that their strong and unique relationship with customers (defined for the purposes of this response as residential and commercial customers, as the Companies are not proposing DSM for industrial customers in this Application) provides the greatest value proposition to customers to having the utility continue to deliver DSM programs and offerings directly to the customer. The Companies have the primary relationship with natural gas customers, even those customers that have chosen to go with a gas marketer for commodity supply. The Companies maintain regular communication with customers through the following channels:

- monthly bills
- bill inserts
- customer newsletters
- www.terasengas.com
- interactions with account managers
- customer surveys
- customer events
- mass media communications

Leveraging these regular communications to include conservation messaging and program information, and using the interactions that customers have through the call centre for residential customers, and through account managers for commercial and industrial customers provides good value to customers. The delivery of conservation activity by a third party would simply add another layer of communication and cost to EEC activity. Further, the delivery of conservation messaging by a party other than the utility will increase the number of parties from whom the customer is receiving messaging about energy, increasing customer confusion and diffusing the impact of such messaging.

Research has indicated that customers feel that it is more appropriate for their utility to provide them with energy efficiency information and deliver energy efficiency programs than any other entity – please refer to Attachment 26.1.

Presumably a third party agency would need to create a duplicate customer information system in order to track program participation, again creating an unnecessary duplication and cost.

The Companies have established relationships with trade and industry organizations and with some elements of the supply chain, such as furnace and boiler manufacturers, that would have to be re-created by a third party agency, again leading to added cost. Further, the Companies have relationships with provincial, federal and municipal bodies, as well as NGOs and Energy Efficiency Groups like the Consortium for Energy Efficiency that would again have to be re-created by a third party agency.

Conservation activity needs to be funded in some manner, whether the activity is conducted by a third party agency or a utility. It is the Companies' view that the Terasen Utilities have the greatest interest in keeping customers happy – a happy customer stays a customer – and therefore would strive hardest to ensure that investments in conservation activity are made as efficiently as possible, again ensuring the greatest value proposition for customers. A third party agency would not have the same interest in long-term customer retention and would therefore be more likely to take a short-term, maximum gain view rather than looking at the longer term big picture, which is a key component of successful energy and resource planning.

It is the Companies' view that utilizing a third party agency can sometimes work in jurisdictions where there are a large number of small utilities each offering different incentives. With this Application, the Companies are proposing that the activity for TGI and for TGVI essentially be rationalized, which would leave only two large and two small utilities delivering EEC activity in British Columbia – the Terasen Companies, BC Hydro, FortisBC and Pacific Northern Gas. The Companies' view is that this is a relatively small number of utilities delivering EEC programming in British Columbia, and that there is no need to have the EEC activity delivered by one central agency.

For this and the advantages outlined above, the Companies believe that the delivery of EEC activity by utilities is the optimal model for British Columbia. One exception would be the low-income sector, where direct installation of measures is needed for successful programming.

27.0 Reference: Exhibit B-2, BCUC IR#1 43.2.4.5

27.1 Please confirm that the issue of rate volatility with respect to expensing DSM expenditures can be avoided by placing the DSM in a deferral account and expensing them over a number of years. If not, why not?

Response:

Confirmed and this is precisely the reason the Companies are proposing just such an accounting treatment. The Companies are proposing that the costs are included in a deferral account to be amortized (expensed) over 20 years.

28.0 Reference: Exhibit B-2, BCUC IR#1 43.2.4.6
DSM in Ontario

Ontario Energy Board issued its Decision with Reasons on August 25, 2006 for EB-2006-0021.

On page 36 the Decision it states:

> *The Board was presented with a partial settlement. All parties except SEC agreed as follows:*
>
> *"The general principle is that all measures and programs should exceed a benefit to cost ratio of 1.0 to be included in the portfolio, but exceptions are reasonable where other benefits are apparent (e.g., pilot programs)."*

On page 37 the Decision it states:

> *However, the Board notes that the partial settlement refers to pilot programs as an example of programs where an exception to the threshold of 1.0 may be permitted. The implication is that there may be other types of programs. No other examples were provided. The Board prefers more certainty as to the exceptions in these circumstances. The Board therefore finds that the exception to the TRC threshold should be restricted to pilot programs at this time.*

28.1 Can the Terasen Utilities provide other examples of a measure with a TRC less than one where the benefits are apparent? If so, please provide the other examples.

Response:

Research has uncovered the following examples: In California, in testimony Southern California Gas Company[12] (SoCal Gas) lists two programs with TRC less than one. Sustainable Communities – Santa Monica Demonstration has TRC of 0.94, while Energy Efficiency Education and Training Program has TRC of 0.80. A Program overview and rationale for each initiative are provided below:

4. Sustainable Communities - Santa Monica Demonstration

The Sustainable Communities Program offers a higher tier incentive for sustainable building projects that significantly exceed Title 24 standards. Qualified projects will incorporate high performance energy efficiency and demand reduction technologies, along with clean on-site generation, water conservation, transportation efficiencies and waste reduction strategies. In its first year, SoCalGas will be jointly working with SCE on

---

[12] http://www.socalgas.com/regulatory/documents/2006docs/Besa_EE.pdf

a demonstration project for the City of Santa Monica. With funding primarily from SoCalGas, a 250 kW fuel cell will also be installed at the project site.[13]

Conclusion- the Sustainable Communities program supports state and local objectives to increase energy efficiency and encourage local renewable generation. It provides a holistic approach to building design and construction with a long-term goal to create sustainable communities through the adoption of new policies and increased market acceptance. The program will achieve significant success by leveraging existing resources, collaborating with region stakeholders, and conducting creative marketing activities.[14].

D. Energy Efficiency Education & Training Program

The Energy Efficiency Education and Training Program is an information program that promotes energy efficiency to a variety of customer segments through the SoCalGas Energy Resource Center ("ERC"), Food Service Equipment Center ("FSEC"), and other information and training programs. The objective is to (1) disseminate information about energy efficiency technology and practices to utility customers for the purpose of assisting them in reducing energy usage, lowering their utility bills, reducing operation and maintenance costs, and improving their productivity; and (2) provide services to a variety of midstream and upstream market actors who use information and tools to design more efficient buildings or processes, and to conduct energy-efficient retrofits and renovations.[15]

Program Rationale - Customers often lack the knowledge or expertise to effectively address energy efficiency challenges. Feedback attained through PAG proceedings supports the concept that Education and Training plays an integral role to encourage the adoption of energy efficient technologies and best practices. As an experienced provider of education and training programs, with a state-of-the-art facility and a successful curriculum in place, SoCalGas incurs nominal additional expenses to continue offering quality seminars on current topics requested by customers. The Education and Training program provides outreach to customers enabling them to recognize energy efficiency opportunities and new technologies. The Education and Training Program plays a significant role in the diffusion of technologies and the dissemination of other energy efficiency and PGC program information, such as incentive and rebate programs. Through these efforts there is greater potential to minimize lost energy savings opportunities.[16].

[13] http://www.socalgas.com/regulatory/documents/2006docs/Besa_EE.pdf, p. AMB-16
[14] http://www.socalgas.com/regulatory/documents/2006docs/Besa_EE.pdf Attachment C, Program Concept Papers, p. 72
[15] http://www.socalgas.com/regulatory/documents/2006docs/Besa_EE.pdf, p. AMB-16
[16] http://www.socalgas.com/regulatory/documents/2006docs/Besa_EE.pdf Attachment C, Program Concept Papers, p. 107

29.0 Reference: Exhibit B-2, BCUC IR#1 43.2.4.6; and Exhibit B-1, Appendix 4, p. 29

The response to BCUC IR#1 43.2.4.6 states: “The OEB has mandated an incentive mechanism, the Shared Savings Mechanism (“SSM”). This incentive mechanism rewards the utility for success in DSM.” The incentive is based on a sliding scale where higher performance is rewarded with a higher payout.

29.1 Do the Terasen Utilities consider the SSM as an acceptable incentive to align both shareholder and ratepayer interests in achieving the maximum TRC result for the DSM spend?

Response:

The Terasen Utilities believe that the appropriate treatment for the EEC expenditures is to capitalize the expenditures as described in section 6.12, p.80 of the Application (Exhibit B-1) and reiterated in BCUC IR#1 10.2. Further, as stated on p.81 of the Application, the Companies feel that setting a target on which an incentive would be paid out could prove to be challenging and contentious given the Companies have not previously established a target for energy savings from EEC expenditures.

Capitalization of EEC expenditures is also consistent with the Energy Conservation and Efficiency Policies outlined in the “The BC Energy Plan: A Vision for Clean Energy Leadership”. Policy item #2 (Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia). The Terasen Utilities believe that the capitalization of the Companies’ EEC expenditures would be consistent with the treatment approved for the two major electric utilities, BC Hydro and Fortis BC and would help the utilities develop a coordinated approach to energy conservation. Additionally, the accounting treatment proposed by the Companies will allow the Terasen Utilities to earn a return on the EEC expenditures, which is consistent with Section 60 (b)(ii) of the Utilities Commission *Act* that states:

> *“Provides to the public utility for which the rates is set a fair and reasonable return on any expenditure made by it to reduce energy demands”*

It is the understanding of the Companies that under the OEB mandated SSM, EEC expenditures are expensed in the year incurred and shareholders only receive an incentive in the event that program results exceed certain criteria. This means that shareholders do not necessarily earn a return on the expenditures made for energy efficiency and conservation programs. This result would be contrary to the Utilities Commission Act. Accordingly, the Companies are of the view that the SSM is not an acceptable incentive mechanism to align shareholder and ratepayer interests for utilities in British Columbia.

29.2 Would the SSM be better than capitalizing to rate base, in terms of aligning the shareholder incentive to maximize TRC results for the ultimate goal of energy conservation? Please discuss.

Response:

Please see response to BCUC IR 2.29.1.

29.3 If the Commission determined that an incentive mechanism would be a superior method of rewarding the utilities for promoting and undertaking cost-effective DSM, what form of incentive mechanism would the Companies propose? Please provide a detailed description of the type of mechanism.

Response:

The Companies are receptive to a mechanism that provides a fair return to shareholders and provides optimal benefit for its customers. The Companies are of the view that the financial treatment proposed in its Application is superior to an incentive mechanism, for the purposes of rewarding utilities in British Columbia for promoting and undertaking cost-effective EEC programs. For a further discussion, please refer to the response to BCUC IR 2.29.1.

As previously discussed, successful DSM will contribute to reduced demand and future expansion requirements and therefore restrict the Companies' ability to expand its business in the future. Incentive mechanisms are unlikely to provide the utility the same opportunity to generate additional future earnings consistent with system expansion. The Companies believe that the proposed capitalization of EEC expenditures helps to alleviate the dis-incentive that successful DSM programs could create.

However, in an attempt to be responsive to the hypothetical scenario set out in the question, the Companies are of the view that there may be some merit in an incentive mechanism similar to that approved for FortisBC (please refer to the response to BCUC IR 2.29.4 below), which allows for incentives over and above a return on its EEC expenditures.

29.4 FortisBC's current DSM incentive mechanism is described in Exhibit B-1, Appendix 4, at pages 8 and9. Please provide the results in terms of target and actual savings, target and actual costs, and incentive received, for the most recent five years available. Please comment on whether Terasen would consider such a mechanism to be acceptable in its case? If not, why not?

Response:

The results[17] in terms of target and actual savings, target and actual costs, and incentive received for the years 2002-2007 are listed below:

---

[17] Source: Email correspondence, Keith Veerman, PowerSense Department, FortisBC, August 2008.

To December 31, 2007; Energy Savings by Year (GW.h)

Year	Plan	Actual	% of Plan Achieved
2002	14.1	16.3	116%
2003	15.6	18.5	119%
2004	14.7	21.3	145%
2005	19	23.9	126%
2006	20.4	23.1	113%
2007	21.8	27.9	128%

Cumulative Fortis Costs

To December 31, 2007; Cost by Year ($000)

Year	Plan	Actual	% of Plan	$/MWh
2002	$ 1,661	$ 1,555	94%	95
2003	$ 1,840	$ 1,706	93%	92
2004	$ 1,814	$ 1,989	110%	93
2005	$ 1,835	$ 2,350	128%	98
2006	$ 2,234	$ 2,241	100%	97
2007	$ 2,474	$ 2,549	103%	91

DSM Incentive Earned

To December 31, 2007; Incentive by Year ($)

Year	Actual
2002	$ 61,810
2003	$ 69,000
2004	$ 58,000
2005	$ 99,000
2006	$ 76,400
2007	$ 119,500

As stated in the response to BCUC IR 2.29.3, the Companies are receptive to a mechanism that provides a fair return and provides optimal benefit for its customers. The Companies are of the view that the above noted mechanism contains components that may assist in meeting that goal. In the PowerSense model, EEC expenditures are treated as deferred expenditures. These deferred expenditures are factored into the rate base and FortisBC earns an approved rate of return over the approved amortization period. These earnings are in addition to any earnings that FortisBC might receive as an incentive as a result of the Shared Savings Mechanism (‘SSM”) that FortisBC currently uses.

As illustrated in the chart above, FortisBC has been successful in maximizing the resource savings acquisition per dollar spent and has received an incentive for each of the last 5 years.

29.5 The Performance Incentive Mechanism (PIM) and the Global Energy Efficiency plan Performance Incentive (GEEP) is described for Gaz Metro in Exhibit B-1, Appendix 4, at pages 20-22. Please comment on whether Terasen would consider such a mechanism to be acceptable in its case? If not, why not?

Response:

Under Gaz Metro's PIM, the utility receives an incentive based on the projected cost of service using a formula which includes consideration for the impact on volumes of energy efficiency measures. This incentive is based on a Reference Formula which allows Gaz Metro to retain a portion of the difference between the cost of service and the result obtained by applying the Reference Formula. If the costs of service exceed the result obtained by applying the Reference Formula, Gaz Metro has to either offset the difference or return a portion to the ratepayers.

The Reference Formula is based on the previous year's revenues plus inflation and adjustments for factors that affect volumes. One of these factors is the impact on volumes of energy efficiency measures. Gaz Metro receives compensation for 90 per cent of volume variations attributed to energy efficiency measures. Under the GEEP, Gaz Metro is tied to a targeted annual savings for a five year period. If Gaz Metro does not reach its goal in any one year, they do not receive a full yearly payout but a prorated incentive.

The Gaz Metro PIM and GEEP would not be an appropriate mechanism for the Companies to consider because under this plan, all EEC expenditures are expensed, and the shareholder may not necessarily earn a fair and reasonable return on its EEC expenditures.

29.6 Appendix 4 (page 29) of Exhibit B-1 states that the incentive mechanism in place "…ensures that program savings are real and verified and imposes penalties for sub-standard performance…."

Does Terasen support an approach that ensures that program savings are real and verified and imposes penalties for sub-standard performance? Why or why not?

Response:

The Companies support an approach that ensures that program savings are real and verified. To this end, the Companies have proposed a portfolio approach for the evaluation of its EEC programs. The Companies are seeking Commission approval for the overall incremental expenditures as outlined in Table 1.4.1 of the Application and have asked for the flexibility to redirect funds from one program area to another program area that the Companies believe will more readily meet the goals based on the assessment criteria outlined in the Application.

If the Companies receive Commission approval for the EEC spending levels as requested in the Application, cumulative annual savings in nominal (as opposed to present value) GJs is projected to result in savings reaching 6.4 million GJs by 2016. While this is a substantial savings, the Companies have not proposed an incentive based mechanism in its Application. The Companies believe that the optimum benefit for the ratepayer would be the approval of the Companies' proposed financial treatment. The Companies are of the view that imposition of penalties to shareholders will not result in greater alignment between shareholder and customer interest with respect to EEC expenditures. Additionally, any regime that included penalties for the Terasen Utilities would create a major difference between the programs of the Companies and the large electric utilities in the Province. This would not be appropriate in the opinion of the Companies.

30.0 Reference: Exhibit B-2, BCUC IR#1 46.1, Free Riders

30.1 Please prepare a summary table showing, for each program, the net to gross ratio, the period over which savings were calculated, and an explanatory column showing whether the ratio was derived from empirical studies, market surveys, or judgment. If the latter please describe whose judgment was involved.

<u>Response:</u>

The two tables below show free rider rates, net to gross ratio, measure life and an explanatory column that specifies the approach used to derive information listed. An explanatory note below the table describes each of the four approaches in detail.

Residential Measures

Measure	Company	Market	FRR Estimate	Net to Gross Ratio	Measure life (years)	Approach/ Sources
EE E* Furnace Upgrade	TGI	Retrofit	28%	72%	18	1
	TGVI	Retrofit	28%	72%	18	1
FS E* Furnace Upgrade	TGVI	Retrofit	0%	100%	18	4
EE EnerChoice Fireplace	TGI	New	10%	90%	15	4
		Retrofit	24%	76%	15	1
	TGVI	New	10%	90%	15	2
		Retrofit	10%	90%	15	4
FS EnerChoice Fireplace	TGVI	Retrofit	10%	90%	15	4
EE E* Dishwashers	TGI	New	38%	62%	13	2
		Retrofit	33%	67%	13	2
	TGVI	New	38%	62%	13	2
		Retrofit	33%	67%	13	2
EE E* Clothes Washers	TGI	New	33%	67%	14	2
		Retrofit	33%	67%	14	2
	TGVI	New	33%	67%	14	2
		Retrofit	33%	67%	14	2
FS Natural Gas Water Heating	TGVI	New	10%	90%	10	4
FS Gas Cooking Range	TGI	New	43%	57%	18	2
	TGVI	New	40%	60%	18	2
		Retrofit	40%	60%	18	2
FS Gas Clothes Dryer	TGI	New	3%	97%	18	4
	TGVI	New	20%	80%	18	2
		Retrofit	5%	95%	13	4

Commercial Measures						
Measure	Company	Market	FRR Estimate	Net to Gross Ratio	Measure life (years)	Approach/ Sources
EE Building Design (30% Large)	TGI	New	5%	95%	25	3
	TGVI	New	5%	95%	25	3
EE Building Design (30% Small)	TGI	New	5%	95%	25	3
	TGVI	New	5%	95%	25	3
EE Building Design (60%)	TGI	New	5%	95%	25	3
	TGVI	New	5%	95%	25	3
High Performance Glazing HIT	TGI	New	5%	95%	25	3
	TGVI	New	5%	95%	25	3
Near Condensing Boilers	TGI	New	18%	82%	25	1
		Retrofit	20%	80%	25	4
	TGVI	New	18%	82%	25	1
		Retrofit	20%	80%	25	4
Condensing Boilers	TGI	New	18%	82%	25	1
		Retrofit	10%	90%	25	4
	TGVI	New	18%	82%	25	1
		Retrofit	10%	90%	25	4
Building Recommissioning	TGI	Retrofit	5%	95%	10	4
	TGVI	Retrofit	5%	95%	10	4
Next Generation BAS	TGI	Retrofit	5%	95%	10	4
	TGVI	Retrofit	5%	95%	10	4
Demand Control Ventilation (Large)	TGI	Retrofit	25%	75%	15	4
Demand Control Ventilation (Medium)	TGI	Retrofit	25%	75%	15	4
High Efficiency Roof Top Units	TGI	Retrofit	0%	100%	20	4
	TGVI	Retrofit	0%	100%	20	4
Instantaneous DHW Heaters	TGI	New	15%	85%	15	4
		Retrofit	10%	90%	15	4
	TGVI	New	15%	85%	15	4
		Retrofit	10%	90%	15	4
Condensing DHW Boilers	TGI	New	0%	100%	25	4
		Retrofit	5%	95%	25	4
	TGVI	New	0%	100%	25	4
		Retrofit	5%	95%	25	4
Condensing DHW Heaters	TGI	New	0%	100%	10	4
		Retrofit	5%	95%	10	4
	TGVI	New	0%	100%	10	4
		Retrofit	5%	95%	10	4
Drainwater Heat Recovery	TGI	New	2%	98%	20	4
	TGVI	New	2%	98%	20	4

Explanation note for Approach/Sources for Free Rider/Net-to-Gross:

A number of different approaches have been used to estimate the free rider rate (FRR) that may be associated with the individual program.

1. In cases where Terasen Gas has operated a program which has been evaluated, the free rider rate from the evaluation has been used. In the evaluations, the FRR has typically been determined by a combination of information from: a customer survey; a trade ally survey; and in some cases by discrete choice analysis modeling using participant and non-participant data.

2. For other programs, the approach has been to estimate the sales of energy efficient products sold in the specific market and then estimate the level of projects program sales. The ratio of existing energy efficient products sold prior to the program and the estimated program sales provides the estimated FRR rate.

3. In some cases, other utilities have operated similar programs in the same or similar marketplaces. In this case, the FRR from the other program has been used.

4. In some cases, "expert" opinion has been used. This may be from industry people outside of the utility or from Terasen Gas field staff who work closely with the trades and major customers.

31.0 Reference: Exhibit B-2, BCUC IR#1 48.1, RIM

31.1 Please provide the "Revenue Impact" with and without free riders, by customer class.

Response:

Please refer to schedule that follows. Revenue impact is calculated as the program benefits (savings) divided by the sum of the total utility program costs plus total revenue loss. Only the numerator changes when considering free riders. Program benefits with free riders included are greater than those benefits calculated without free riders. The denominator remains the same; sum of total utility program costs plus total revenue loss.

For completeness, the revenue impact for both the Residential Energy Efficiency programs and the Residential Fuel Substitution programs are shown separately.

2008 DSM PLAN VERSION 080710 Combined

2008 - 2010 (NPV 2007)	REVENUE IMPACT – Over the life of the measures: Revenue Requirement ($000)	REVENUE IMPACT – Over the life of the measures: Gas Delivered (2007) $/GJ	PROGRAM: Participants	COSTS ($000) – Utility: Incentives	COSTS ($000) – Utility: Admin-istration	COSTS ($000) – Utility: Total	COSTS ($000): Participant	COSTS ($000): Total	COSTS ($000): % Utility	COSTS ($000): % Participant	SAVINGS (GJ): Gross	SAVINGS (GJ): Net	ALTERNATE Impact: Energy MWh	ALTERNATE Impact: Capacity kW
RESIDENTIAL:														
Residential Energy Efficiency														
With Free Riders	23,470	0.19	48,272	5,686	2,499	8,185	3,217	11,402	72%	28%	284,445	210,572	4,194	-
Without Free Riders	15,977	0.13	48,272	5,686	2,499	8,185	3,217	11,402	72%	28%	284,445	284,445	4,194	-
Residential Fuel Substitution														
With Free Riders	-13,046	-0.10	20,755	2,180	1,059	3,239	-260	2,978	109%	-9%	-251,020	-200,252	46,148	-
Without Free Riders	-7,437	-0.06	20,755	2,180	1,059	3,239	-260	2,978	109%	-9%	-251,020	-251,020	46,148	-
Total Residential														
With Free Riders	10,424													
Without Free Riders	8,540													
COMMERCIAL:														
With Free Riders	48,641	0.38	1,147	17,928	5,178	23,106	18,551	41,657	55%	45%	699,363	607,378	53,438	-
Without Free Riders	36,891	0.29	1,147	17,928	5,178	23,106	18,551	41,657	55%	45%	699,363	699,363	53,438	-

2008 - 2010 (NPV 2007)	NET PRESENT VALUE: Levelized Cost ($/GJ)	Utility Benefits (Costs): Program ($'000s)	Utility Benefits (Costs): Alternate ($'000s)	Participant Benefits (Costs): Program ($'000s)	Participant Benefits (Costs): Carbon Tax ($'000s)	Participant Benefits (Costs): Alternate ($'000s)	Program Net Savings: Natural Gas (GJ)	Program Net Savings: Alternate Energy (MWh)	Program Net Savings: Alternate Capacity (kW)	BENEFIT/COST: Natural Gas Utility	Participant: Total Costs ($'000s)	Participant: Total Benefits ($'000s)	Participant: Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
RESIDENTIAL:																
Residential Energy Efficiency																
With Free Riders	4	21,516	3,973	36,801	4,288	2,851	2,267,984	30,563	-	**2.6**	**3,217**	**43,940**	**13.7**	**0.5**	**2.2**	**14,087**
Without Free Riders	2.7	29,009	5,849	36,801	4,288	2,851	3,056,996	44,992	-	**3.5**	**3,217**	**43,940**	**13.7**	**0.6**	**3.1**	**23,456**
Residential Fuel Substitution																
With Free Riders	FS	-21,255	62,196	-37,541	-4,056	34,844	-2,277,629	478,431	-	**FS**	**41,596**	**35,104**	**0.8**	**1.5**	**2.6**	**37,962**
Without Free Riders	FS	-26,865	71,491	-37,541	-4,056	34,844	-2,867,576	549,931	-	**FS**	**41,596**	**35,104**	**0.8**	**1.2**	**2.4**	**41,648**
Total Residential																
With Free Riders																
Without Free Riders																
COMMERCIAL:																
With Free Riders	3	76,445	71,575	101,980	12,577	32,339	7,690,292	550,575	-	**3.3**	**18,551**	**146,896**	**7.9**	**0.6**	**3.6**	**106,363**
Without Free Riders	2.6	88,195	75,342	101,980	12,577	32,339	8,872,108	579,553	-	**3.8**	**18,551**	**146,896**	**7.9**	**0.7**	**3.9**	**121,880**

31.2 Since it appears that Terasen has modeled the results assuming that the market price of natural gas is, for residential and commercial customers, less than the rate charged customers, does this result in a RIM that must always be less than one?

Response:

The avoided cost applied in the model is the natural gas commodity, while retail customer rates include fixed and variable costs associated with assets and delivery as well as, for full service customers, the cost of natural gas.

For this reason the model will provide a revenue impact benefit cost ratio of less than one.

31.3 Why is it correct to model the results assuming the market price of the commodity, as opposed to market price of the commodity plus an allowance for the long run incremental cost of the “pipes”? Does Terasen have an estimate of this LRIC, and if so what impact would it have on the results?

Response:

An allowance for the long run incremental cost of the “pipes” reflecting distribution costs and system improvements has been included in the gas supply cost analysis that underpins RIM results presented in the Application. The impact of these pipes-related costs, however, is small in comparison to the impact of annual commodity cost savings. The RIM results are slightly higher than they would have been if this allowance had not been included. Please also refer to the Companies' response to BCUC IR 2.9.3.

32.0 Reference: Exhibit B-2, BCUC IR#1 52.2.1

32.1 Please provide the number of accounts associated with the figures shown in the table for BCUC IR#1 52.2.1.

Response:

The number of accounts associated with the figures shown in the table for BCUC IR 1.52.2.1 are as follows:

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Number of Accounts	94,124	97,688	101,624	105,472	109,546	113,334	116,803	120,273	123,608	126,611	129,316	131,907	134,236

32.2 Please explain how the proposed DSM programs are expected to affect the number of Residential accounts, and the proportion of households choosing natural gas.

Response:

The Residential Energy Efficiency program area is targeted at existing customers, and is not expected to affect the number of Residential accounts. The Residential Fuel Switching for TGVI Retrofits is targeted at potential TGVI customers who are currently using an alternative energy source for heating - there are 1,593 participants forecast for the Fuel Switching Energy Star Furnace/Boiler program. According to the 2006 census, British Columbia has a total number 1,642,715 dwellings, so the proportion of that total that may choose natural gas as a heating source as a result of the residential retrofit program for TGVI is 0.1%. The Residential Fuel Switching for TGVI New Construction is targeted at builders, and the number of participants for the Domestic Hot Water program is forecast to be 1,170. The proportion of total dwellings in British Columbia that may choose natural gas to heat domestic hot water as a result of the residential new construction program for TGVI is 0.07%. The other programs in the Residential Fuel Switching program area are focussed on gas cooking ranges and dryers. These should be considered load-building programs and would not affect the number of Residential accounts.

33.0 Reference: Exhibit B-2, BCUC IR#1, pp. 121-127

33.1 Using for TGI the expenditure schedule set out for the response to question 52.4, and a schedule based on similar assumptions for TGI, please provide tables showing the cost of service and cost/GJ (similar to those on pages 121 and 123 of the responses). Please also provide tables in a similar format showing the cost of service and cost/GJ if the costs are expensed and amortized over 20 years.

<u>Response:</u>

Please refer to the following schedule.

TERASEN GAS INC. (3 Divisions)
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	2029	2030	2031	2032
Current DSM																									
Beginning of Year Balance	$ 1,526	$ 754	$ 370	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(772)	(384)	(353)	(17)																					
End of Year Balance	754	370	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EEC																									
Beginning of Year Balance	-	8,537	17,999	29,287	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613
Additions	12,372	14,128	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196
Tax Adjustment	(3,835)	(4,238)	(4,987)	(4,729)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)
Net Additions	8,537	9,890	12,209	12,467	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725
Amortization	-	(427)	(921)	(1,532)	(2,155)	(2,791)	(3,428)	(4,064)	(4,700)	(5,336)	(5,973)	(6,609)	(7,245)	(7,881)	(8,518)	(9,154)	(9,790)	(10,426)	(11,063)	(11,699)	(12,335)	(12,545)	(12,686)	(12,712)	(12,725)
End of Year Balance	8,537	17,999	29,287	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613	133,613
Total Deferred DSM																									
Beginning of Year Balance	1,526	9,291	18,369	29,304	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613
Additions	12,372	14,128	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196
Tax Adjustment	(3,835)	(4,238)	(4,987)	(4,729)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)
Net Additions	8,537	9,890	12,209	12,467	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725
Amortization	(772)	(811)	(1,274)	(1,549)	(2,155)	(2,791)	(3,428)	(4,064)	(4,700)	(5,336)	(5,973)	(6,609)	(7,245)	(7,881)	(8,518)	(9,154)	(9,790)	(10,426)	(11,063)	(11,699)	(12,335)	(12,545)	(12,686)	(12,712)	(12,725)
End of Year Balance	9,291	18,369	29,304	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613	133,613
Cost of Service																									
Operating & Maintenance Expense	1,624	1,624	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization Expense	772	811	1,274	1,549	2,155	2,791	3,428	4,064	4,700	5,336	5,973	6,609	7,245	7,881	8,518	9,154	9,790	10,426	11,063	11,699	12,335	12,545	12,686	12,712	12,725
Income Tax Expense	420	526	814	985	1,240	1,572	1,898	2,216	2,528	2,834	3,132	3,424	3,709	3,987	4,259	4,523	4,782	5,033	5,277	5,515	5,746	5,823	5,874	5,883	5,888
Earned Return - Debt	241	617	1,063	1,550	2,029	2,487	2,915	3,316	3,688	4,032	4,347	4,634	4,892	5,123	5,324	5,498	5,643	5,760	5,848	5,908	5,940	5,952	5,957	5,958	5,959
Earned Return - Equity	163	417	719	1,049	1,373	1,683	1,973	2,244	2,496	2,728	2,942	3,136	3,311	3,467	3,603	3,721	3,819	3,898	3,957	3,998	4,019	4,028	4,031	4,032	4,032
Earned Return	$ 404	$ 1,034	$ 1,782	$ 2,599	$ 3,403	$ 4,169	$ 4,888	$ 5,560	$ 6,184	$ 6,760	$ 7,289	$ 7,770	$ 8,203	$ 8,589	$ 8,928	$ 9,219	$ 9,462	$ 9,657	$ 9,806	$ 9,906	$ 9,959	$ 9,980	$ 9,988	$ 9,990	$ 9,991
Total Cost of Service	$ 3,221	$ 3,995	$ 3,871	$ 5,134	$ 6,798	$ 8,533	$ 10,214	$ 11,840	$ 13,412	$ 14,930	$ 16,393	$ 17,803	$ 19,157	$ 20,458	$ 21,704	$ 22,896	$ 24,033	$ 25,117	$ 26,146	$ 27,120	$ 28,040	$ 28,348	$ 28,549	$ 28,586	$ 28,604
Volume (TJ/year)	139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554
Cost $/GJ	$0.0230	$0.0281	$0.0270	$0.0354	$0.0463	$0.0575	$0.0681	$0.0781	$0.0875	$0.0965	$0.1051	$0.1132	$0.1208	$0.1290	$0.1369	$0.1444	$0.1516	$0.1584	$0.1649	$0.1710	$0.1769	$0.1788	$0.1801	$0.1803	$0.1804

33.2 Please provide a set of tables showing the same information as in the immediately preceding question, except assuming that costs (whether expensed or amortized) are amortized over 10 years.

Response:

Please refer to the following schedule.

TERASEN GAS INC. (3 Divisions)
DEMAND SIDE MANAGEMENT
$000's

Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Current DSM															
Beginning of Year Balance	$ 1,526	$ 754	$ 370	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(772)	(384)	(353)	(17)											
End of Year Balance	754	370	17	-	-	-	-	-	-	-	-	-	-	-	-
New EEC															
Beginning of Year Balance	-	8,537	17,573	27,939	37,343	45,757	52,900	58,770	63,367	66,692	68,744	69,524	69,031	67,266	64,228
Additions	12,372	14,128	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196
Tax Adjustment	(3,835)	(4,238)	(4,987)	(4,729)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)
Net Additions	8,537	9,890	12,209	12,467	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725
Amortization	-	(854)	(1,843)	(3,064)	(4,310)	(5,583)	(6,855)	(8,128)	(9,400)	(10,673)	(11,945)	(13,218)	(14,490)	(15,763)	(17,035)
End of Year Balance	8,537	17,573	27,939	37,343	45,757	52,900	58,770	63,367	66,692	68,744	69,524	69,031	67,266	64,228	59,918
Total Deferred DSM															
Beginning of Year Balance	1,526	9,291	17,943	27,956	37,343	45,757	52,900	58,770	63,367	66,692	68,744	69,524	69,031	67,266	64,228
Additions	12,372	14,128	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196
Tax Adjustment	(3,835)	(4,238)	(4,987)	(4,729)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)
Net Additions	8,537	9,890	12,209	12,467	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725
Amortization	(772)	(1,238)	(2,196)	(3,081)	(4,310)	(5,583)	(6,855)	(8,128)	(9,400)	(10,673)	(11,945)	(13,218)	(14,490)	(15,763)	(17,035)
End of Year Balance	9,291	17,943	27,956	37,343	45,757	52,900	58,770	63,367	66,692	68,744	69,524	69,031	67,266	64,228	59,918
Cost of Service															
Operating & Maintenance Expense	1,624	1,624	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization Expense	772	1,238	2,196	3,081	4,310	5,583	6,855	8,128	9,400	10,673	11,945	13,218	14,490	15,763	17,035
Income Tax Expense	420	707	1,180	1,542	1,955	2,485	3,001	3,503	3,992	4,468	4,930	5,379	5,814	6,235	6,644
Earned Return - Debt	241	607	1,023	1,456	1,853	2,200	2,490	2,723	2,900	3,020	3,083	3,089	3,039	2,932	2,768
Earned Return - Equity	163	411	693	985	1,254	1,489	1,685	1,843	1,963	2,044	2,086	2,091	2,057	1,984	1,873
Earned Return	$ 404	$ 1,018	$ 1,716	$ 2,441	$ 3,107	$ 3,689	$ 4,175	$ 4,566	$ 4,863	$ 5,064	$ 5,169	$ 5,180	$ 5,096	$ 4,916	$ 4,641
Total Cost of Service	$ 3,221	$ 4,586	$ 5,091	$ 7,064	$ 9,372	$ 11,756	$ 14,031	$ 16,197	$ 18,255	$ 20,204	$ 22,045	$ 23,777	$ 25,400	$ 26,914	$ 28,320
Volume (TJ/year)	139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	159,812	161,070
Cost $/GJ	$0.0230	$0.0323	$0.0355	$0.0487	$0.0638	$0.0792	$0.0935	$0.1068	$0.1192	$0.1307	$0.1413	$0.1512	$0.1602	$0.1684	$0.1758

34.0 Reference: Exhibit B-2, BCUC IR#1 53.2, Attachment 53.2, and Exhibit B-1, Tables 6.13, 6.13a, and 7.2

34.1 The BC Hydro Conservation Potential Review, filed as an attachment to the response to BCUC IR#1 53.2, uses a GHG emissions factor for post-2016 of zero. Given this approach, does Terasen agree that any fuel switching benefits in the Application (from electricity to natural gas) should only be credited to the end of F2016? If not, why not?

Response:

No, Terasen does not agree that fuel switching benefits should only be credited to the end of 2016. Fuel switching programs will continue to result in reduced GHG emissions in the region after BC Hydro reaches energy self sufficiency by 2016 as set out in the BC Energy Plan (see also the response to BC Hydro IR 1.10.1). The report provided as Attachment 34.1 from the Northwest Power and Conservation Council shows that the region's marginal electricity resource will continue to be primarily natural gas fired generation well beyond 2016 (see Figure 4, page 9 of Attachment 34.1). Available and surplus clean electricity from BC that results from fuel switching programs will be available to offset natural gas fired marginal resources other jurisdictions both before and beyond 2016. See also the Terasen response to BCSEA IR 1.17.1.

34.2 Assuming that fuel switching benefits are limited to the end of F2016, please show how that would affect the estimates shown in Exhibit B-1, Tables 6.13, 6.13a, and 7.2.

Response:

Table 6.13 - Cost-Benefit Results for EEC Portfolio including Free Rider Factor

The impact of reducing the 18-year life of the savings from the fuel switching measures to 9, 8, and 7 years depending on the respective program year of 2008, 2009, and 2010 as shown below. In particular:

1. The ratepayer benefit/cost ratio declines slightly, as the shorter term decline in utility revenue benefit from fuel switching measures is greater than the decline in shorter term cost of natural gas purchases.

2. The participant benefit/cost ratio remains about the same, as the reduced amount of natural gas purchases (and costs) are offset by the reduced alternate utility savings (and benefits).

3. The total resource net benefits decline because the reduction in alternate utility savings (benefits) is greater than the decline in the utility's natural gas purchases (costs).

Table 6.13 - Cost-Benefit Results for EEC Portfolio including Free Rider Factor

	Rate Payer Impact Measure	Utility	Participant	Total Resource Cost	TRC benefit ($ 000)
Residential Energy Efficiency	0.5	2.6	13.7	2.2	$14,087
Residential Fuel Substitution	1.5	FS	0.8	2.6	$37,962
Commercial Energy Efficiency	0.6	3.3	7.9	3.6	$106,363
Portfolio Level	**0.5**	**1.4**	**8.6**	**2.8**	**$136,577**

Revised 6.13 - Cost-Benefit Results for EEC Portfolio including Free Rider Factor and FS Benefits ending F2016

	Rate Payer Impact Measure	Utility	Participant	Total Resource Cost	TRC benefit ($ 000)
Residential Energy Efficiency	0.5	2.6	13.7	2.2	$14,087
Residential Fuel Substitution	1.4	FS	0.8	2.4	$23,311
Commercial Energy Efficiency	0.6	3.3	7.9	3.6	$106,363
Portfolio Level	**0.5**	**1.5**	**8.7**	**2.6**	**$121,926**

Table 6.13a - Cost-Benefit Results for EEC Portfolio excluding Free Rider Factor

The impact of reducing the 18-year life of the savings from the fuel switching measures to 9, 8, and 7 years depending on the respective program year of 2008, 2009, and 2010 as shown below. In particular:

1. The ratepayer benefit/cost ratio increases slightly, as the shorter term decline in utility revenue benefit from fuel switching measures is less than the decline in shorter term cost of natural gas purchases.

2. The participant benefit/cost ratio remains about the same, as the reduced amount of natural gas purchases (and costs) are offset by the reduced alternate utility savings (and benefits).

3. The total resource net benefits decline because the reduction in alternate utility savings (benefits) is greater than the decline in the utility's natural gas purchases (costs).

Table 6.13a - Cost-Benefit Results for EEC Portfolio excluding Free Rider Factor

	Rate Payer Impact Measure	Utility	Participant	Total Resource Cost	TRC benefit ($ 000)
Residential Energy Efficiency	0.6	3.5	13.7	3.1	$23,456
Residential Fuel Substitution	1.2	FS	0.8	2.4	$41,648
Commercial Energy Efficiency	0.7	3.8	7.9	3.9	$121,880
Portfolio Level	**0.6**	**1.6**	**8.6**	**3.1**	**$165,149**

Revised 6.13a - Cost-Benefit Results for EEC Portfolio excluding Free Rider Factor and FS Benefits ending F2016

	Rate Payer Impact Measure	Utility	Participant	Total Resource Cost	TRC benefit ($ 000)
Residential Energy Efficiency	0.6	3.5	13.6	3.0	$23,359
Residential Fuel Substitution	1.4	FS	0.9	2.8	$35,588
Commercial Energy Efficiency	0.7	3.8	7.9	3.9	$121,880
	0.6	**1.8**	**8.7**	**3.0**	**$158,992**

Table 7.2 - Energy Savings by Activity by Sector by Utility

Consumption Impact				
Sector and Activity	**Natural Gas (GJ)**	**GHG Impact (tonnes C02)**	**Electricity (MWh)**	**GHG Impact (tonnes CO2)**
TGI Residential Energy Efficiency	(2,086,632)	(105,771)	(27,996)	(15,398)
TGI Residential Fuel Switching	831,150	42,131	115,328	63,430
TGI Commercial Energy Efficiency	(6,857,736)	(347,619)	(485,291)	(266,910)
TGVI Residential Energy Efficiency	(181,352)	(9,193)	(2,567)	(1,412)
TGVI Residential Fuel Switching	1,446,479	73,322	(363,103)	(199,707)
TGVI Commercial Energy Efficiency	(832,556)	(42,202)	(65,284)	(35,906)
Subtotal - Energy Efficiency	**(9,958,276)**	**(504,785)**	**(581,138)**	**(319,626)**
Subtotal - Fuel Switching	**2,277,629**	**115,453**	**(247,775)**	**(136,276)**
Totals	**(7,680,647)**	**(389,332)**	**(828,913)**	**(455,902)**

Revised Table 7.2 - Energy Savings by Activity by Sector by Utility FS Benefits ending F2016

Consumption Impact				
Sector and Activity	**Natural Gas (GJ) FRR in**	**GHG Impact (tonnes C02)**	**Electricity (MWh) FRR In**	**GHG Impact (tonnes CO2)**
TGI Residential Energy Efficiency	(2,086,632)	(105,771)	(27,996)	(15,398)
TGI Residential Fuel Switching	479,721	24,317	(64,777)	(35,627)
TGI Commercial Energy Efficiency	(6,857,736)	(347,619)	(485,291)	(266,910)
TGVI Residential Energy Efficiency	(181,352)	(9,193)	(2,567)	(1,412)
TGVI Residential Fuel Switching	986,200	49,990	(239,164)	(131,540)
TGVI Commercial Energy Efficiency	(832,556)	(42,202)	(65,284)	(35,906)
Subtotal - Energy Efficiency	**(9,958,276)**	**(504,785)**	**(581,138)**	**(319,626)**
Subtotal - Fuel Switching	**1,465,921**	**74,308**	**(303,941)**	**(167,168)**
Totals	**(8,492,355)**	**(430,477)**	**(885,079)**	**(486,793)**

35.0 Reference: Exhibit B-2, BCUC IR#1 55.7

35.1 In what years did the Yank the Tank and Think Grand programs begin and end?

Response:

Yank the Tank ran from March 2006 to December 2006.

Think Grand ran from June 2005 to March 2007.

35.2 Are any of the currently proposed programs effectively continuations of the Yank the Tank and Think Grand programs?

Response:

The proposed Energy Efficiency and Conservation program portfolio does not include programs that are continuations of Yank the Tank or Think Grand for the following reasons:

- Think Grand offered incentives to builders and developers in the TGVI jurisdiction if they installed an Energy Star rated natural gas furnace/boiler and a natural gas water heater in new construction residential developments. As per recent New Energy Efficiency Regulations under the Province's Energy Efficiency Act (EEA)[18] which came into effect on January 1, 2008, all new construction requires natural gas forced air furnaces to be Energy Star qualified.[19] Therefore, the Companies can no longer provide incentives for furnaces/boilers in the new construction residential market.

- Yank the Tank offered incentives to new and existing customers for replacing hot water tanks in the residential retrofit market in the TGVI jurisdiction. The Companies did not include a continuation of Yank the Tank because the TRC for Domestic Hot Water Fuel Choice in CPR and CPR Measure Update Screening was less than 1.0.[20]

---

[18] http://142.32.76.167/Electricity%20and%20Alternative%20Energy/EnergyEfficiency/Pages/EEAct.aspx

[19] http://142.32.76.167/Electricity%20and%20Alternative%20Energy/EnergyEfficiency/Documents/EE%20Regulation%20Gas%20Forced%20Air%20Furnaces%20-%20Updated.pdf

[20] EEC Application, Appendix 9, p. , Exhibit 2.8: Residential Energy Efficiency Measure – Re-Screen Summary

36.0 Reference: Exhibit B-2, BCUC IR#1 56.2 and Attachments 56.2A

36.1 Please provided a somewhat expanded description of each program listed in the Table of Contents of Attachment 56.2A.

Response:

Please see the tables below. More information can be found in Exhibit B-1, Sections 6.3 and 6.4 and in Appendix 1 to Exhibit B-1.

Commercial Programs - New Construction	
Program Name	Brief Description
Efficient New Construction	Contributing to integrated design process for buildings that are designed to operate at energy consumption levels 30% below Model National Energy Code for Buildings (MNECB), and at consumption levels 60% below MNECB. See pages 48 and 49 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector. Incentives intended to offset the incremental cost of High-Insulation Technology windows. See pages 45 and 46 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector.
Boilers	Incentives to offset the incremental costs of purchasing and installing condensing and near-condensing boilers. See pages 49 and 50 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector
Water Heating	Incentives to offset the incremental costs of instantaneous domestic hot water (DHW) heater, condensing DHW boiler, condensing DHW heater and drainwater heat recovery. See pages 53 to 55 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector

Commercial Programs - Retrofit	
Program Name	Brief Description
Boilers	Incentives to offset the incremental costs of purchasing and installing condensing and near-condensing boilers. See pages 49 and 50 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector
Building Recommissioning	Incentives to offset costs of building recommissioning and next generation building automation systems. See pages 50 to 51 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector
Demand Control Ventilation	Incentives to offset the incremental costs of demand control ventilation systems. See pages 51 to 52 of Appendix 1 to Exhibit B-1, Terasen Gas CPR, Commercial Sector
High Efficiency Roof Top Unit	Incentives to offset the incremental costs of High Efficiency Roof Top Units. See pages 52 and 53 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector
Water Heating	Incentives to offset the incremental costs of instantaneous domestic hot water (DHW) heater, condensing DHW boiler, condensing DHW heater and drainwater heat recovery. See pages 53 to 55 of Appendix 1 to Exhibit B-1, Terasen Gas CPR Commercial Sector

Residential Programs - New Construction	
Program Name	Brief Description
EE EnerChoice Fireplace	Incentives to offset the incremental costs of Enerchoice fireplaces
EE E* Hot Water Saving Appliances	Incentives to offset the incremental cost of Energy Star Clothes Washers and Dishwashers
FS Gas Cooking Range	Incentives to offset the incremental costs of purchasing and installing natural gas cooking ranges
FS Gas Clothes Dryer	Incentives to offset the incremental costs of purchasing and installing natural gas clothes dryers

Residential Programs - Retrofit	
EE E* Furnace Upgrade	Incentives to offset the incremental costs of purchasing and installing Energy Star furnaces and boilers
EE EnerChoice Fireplace	Incentives to offset the incremental costs of Enerchoice fireplaces
EE E* Hot Water Saving Appliances	Incentives to offset the incremental cost of Energy Star Clothes Washers and Dishwashers

36.2 What determines whether or not an incentive is 50 percent of incremental measure cost (for instance for TGI New EE E* fireplaces the incentive is 100 percent)?

Response:

Terasen Gas has operated DSM programs since the 1990's, and has found that an incentive level of 50% of the incremental cost is generally effective at getting the desired level of customer participation.

However there are some exceptions to the approach.

One would be the EnerChoice fireplaces: manufacturers have indicated that the incremental manufacturing cost to add the efficiency features is about $200. However, at this time the efficient features are typically available on the high end units and bundled with other features such as brass surrounds etc. The incremental cost to the customer of these units is more than the $200 for the efficiency, and a larger incentive than $100 is thought to be necessary to spur participation.

37.0 Reference: Exhibit B-2, BCUC IR#1 56.2, Program Summaries Table 56.2 B 1 TGI Commercial Excluding Free Riders

37.1 Please provide this and related tables including columns AE through AK and any other missing columns.

Response:

Due to the large size of these workbooks, electronic versions are being provided, however, due to the commercial sensitivity of the information requested, the response to this question has been filed under separate cover in accordance with the BCUC Practice Directive pursuant to Section 13 of the *Administrative Tribunals Act* related to Confidential Filings. The Terasen Utilities have requested that the information be made accessible only to the Commission and to those authorized representatives of Registered Intervenors who execute an undertaking, consistent with Attachment A to the BCUC Practice Directive, to hold the information confidential.

38.0 Reference: Exhibit B-2, BCUC IR#1 57.2, Use Rates

38.1 Please explain why the use rate for residential customers is over 25 percent higher in the Lower Mainland than in the interior.

Response:

Residential usage, on a per customer basis, is significantly lower in the interior region mainly due to people building and living according to their climate. Homes in the interior are smaller, better insulated, and a higher proportion have higher efficiency appliances than do homes in the Lower Mainland region.

38.2 Looking at the residential data for TGI, does Terasen agree that the use rates appear to have stabilized after dropping sharply?

Response:

The Terasen Utilities do not expect to see the sharp declines in residential use rates as seen from 2000-2001 (driven by the California Energy Crisis) or 2004-2005 (driven by Hurricane Katrina). However, the Terasen Utilities do expect residential use rates to continue declining, driven mainly by appliance retrofit activity and also a shift in the housing market towards more multi-family dwellings.

38.3 Please state whether the figures shown in the tables in response to BCUC IR#1 57.2 are in current or constant dollars. If the latter, please state the year applicable. Please also state whether the figures shown in response to BCUC IR#1 57.2 are weather normalized.

Response:

The weighted average burner-tip rates per GJ shown in BCUC IR 2.57.2 are in current dollars. The use per customer figures shown are weather normalized figures.

39.0 Reference: Exhibit B-2, BCUC IR#1 60.1, Funding Requested

Terasen states: "This is in the Joint Initiatives program area, and it should be noted that the Companies are seeking high-level approval of the total amount to be expended not to exceed $56.6 million by 2010, rather than funding for specific initiatives such as a building labeling pilot."

39.1 Is it Terasen's position that only the success of that total EEC package should be monitored or that of the individual programs? If there is to be no program by program budget, how will the success of a program be determined?

Response:

It is the Companies' position that the success of individual programs will be monitored, and that those individual programs make up program areas, which then make up the overall EEC portfolio. It is the Companies' intent to monitor individual Energy Efficiency and Fuel Switching programs on a monthly basis, to ensure that the overall EEC portfolio has a TRC of 1.0 or greater on an ongoing basis. The portfolio of EEC activity presented in the Application provides a TRC of well above 1.0, despite including costs but no benefits from the Conservation Education and Outreach, Trade Relations, Joint Initiatives and Innovative Technologies program areas. "Bottom up" budgets have been established for the Residential Energy Efficiency, for the Residential Fuel Switching, for the Commercial Energy Efficiency and for the Conservation Education and Outreach program areas. As noted in the responses to BCUC IRs 1.32.1, 1.33.1 and 1.58.1, the Companies have used their best judgment in establishing directional budgets to work with in the Trade Relations, Innovative Technologies and Joint Initiatives program areas so as to begin to develop programming for these areas. Results tracking methodologies for the Conservation Education and Outreach and Trade Relations program areas are outlined on pages 83 and 84 of Exhibit B-1, the Application, as well as for Innovative Technologies.

40.0 Reference: Exhibit B-2, BCUC IR#1 62.1

40.1 During the BC Hydro Residential Inclining Block Rate Hearing, BC Hydro stated that “There is a lack of policy direction from government on fuel switching at this point in time….” (Transcript Vol. 5, p. 731)

Can Terasen confirm that BC Hydro made that statement during the RIB hearing?

Response:

The Terasen Utilities confirm that according to The Transcript Vol. 5, p. 731, lines 22 and 22 from the Residential Inclining Block Rate Hearing that Ms. Van Ruyven stated, “There is a lack of policy direction from government on fuel switching at this point in time….” Please see response to BCUC IR 2.40.2.

40.2 Is Terasen aware of any BC Government policy that specifically directs or supports electricity to natural gas fuel switching programs? If so please provide the supporting documents.

Response:

The Terasen Utilities are not aware of any BC Government policy that specifically directs or supports electricity to natural gas fuel switching programs, nor any policy to the contrary. However, the Commission has been directed to consider "government's energy objectives", which include "(a) to encourage public utilities to reduce greenhouse gas emissions". For the reasons explained in BCUC IR 1.62.1, the Terasen Utilities believe that fuel switching programs are consistent with that objective. Measures designed to reduce electricity load will also assist BC Hydro in achieving its self-sufficiency.

The Commission's DSM Accounting Policy specifically recognizes fuel substitutions as a DSM strategy and states, in part:

3. Load building by Fuel Substitution

Utilities engaged in strategic load building by fuel substitution may account for this in the same manner as other DSM strategies subject to Commission directions specific to that utility.

41.0 Reference: Exhibit B-2, BCUC IR#1 64.1 Assumption on Appliance Usage

41.1 Terasen states that Marbek estimated natural conservation based on assumptions around the modest continuation of appliance penetration trends. Please provide a summary table of the 20 year forecast of natural conservation by sector and appliance or asset, and the annual GJ usage forecast for each sector for the period and include the estimated real retail price for each sector in each year.

<u>Response:</u>

Terasen Gas does not forecast natural gas usage based on end use and natural conservation by sector and hence this level of detail is not available. Information on expected change in appliance efficiency is noted on pages 38 - 41 of the Residential Section of Appendix 1, and have been summarized as part of the response to the following question. The capital stock turnover model is embedded in Marbek proprietary models and is not available.

42.0 Reference: Exhibit B-2, BCUC IR#1 67.1, Changing End Uses

42.1 Information Request 67.1 asked for a summary of the use data for major appliances from 1980 to the present in support of the assumption that further appliance efficiencies will be relatively minor, and asked for similar information for furnaces. The attached response was a 190 page document.

Please provide the summary requested, or describe the specific sections in Attachment 67.1 relied upon by Terasen for that assumption.

Response:

Information Request 67.1 asked "for a summary of the use data for major appliances from 1980 to the present" however the date used to formulate our assumptions was data from 1990 to 2005. Therefore, the following data tables from the Energy Use Data Handbook, 1990 to 2005 are a summary of the use data for major appliances and support the assumption that further appliance efficiencies will be relatively minor.

The tables contain the same data found in NRCan's 2003 Survey of Household Energy Use (SHEU) – Summary Report plus data for 2004 and 2005 that support our assumptions.

http://www.oee.nrcan.gc.ca/Publications/statistics/sheu-summary/index.cfm

Major Appliances

Table 1 is a summary of residential appliance of total appliance energy use (PJ) from 1990 to 2005.

Table 1

Natural Resources Canada | Ressources naturelles Canada | Canada

Residential Appliance Details

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total Growth 1990–2005
Total Appliance Energy Use (PJ) [a]	**197.3**	**192.4**	**195.0**	**190.6**	**191.1**	**188.2**	**191.8**	**192.7**	**191.3**	**191.6**	**196.4**	**200.6**	**198.0**	**202.6**	**209.3**	**203.0**	**2.9%**
Energy Use by Energy Source (PJ) [a]																	
Electricity	193.7	188.8	191.6	186.8	187.3	184.4	187.5	188.3	186.8	187.2	191.9	195.9	193.1	197.1	204.3	197.5	2.0%
Natural Gas	3.7	3.6	3.4	3.8	3.8	3.8	4.3	4.4	4.5	4.4	4.6	4.7	4.9	5.5	5.0	5.5	50.0%
Energy Use by Appliance Type (PJ) [a]																	
Refrigerator	66.2	63.1	62.8	60.0	57.9	55.4	54.9	53.2	50.9	50.2	49.4	48.7	46.4	45.8	47.1	43.6	-34.2%
Freezer	26.7	25.7	25.4	24.4	24.1	22.7	22.4	22.0	20.6	19.3	18.9	18.2	16.7	15.9	15.1	14.3	-46.7%
Dishwasher [1]	4.3	4.3	4.1	4.0	4.1	3.9	3.9	3.7	3.7	3.4	3.5	3.4	3.3	3.2	3.2	3.0	-29.9%
Clothes Washer [1]	2.9	2.8	2.9	2.8	2.9	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.8	2.8	2.8	2.6	-9.9%
Clothes Dryer	35.4	34.1	34.5	33.8	33.8	33.7	34.3	35.0	35.2	34.8	36.0	37.1	36.1	37.1	38.3	37.7	6.5%
Range	30.2	29.6	30.4	30.2	31.0	31.0	32.2	32.2	32.5	33.3	34.5	35.7	35.7	37.2	37.8	36.9	22.4%
Other Appliances [2]	31.6	32.7	34.9	35.3	37.3	38.7	41.3	43.7	45.4	47.8	51.3	54.6	56.9	60.5	64.9	64.9	105.2%
Activity																	
Total Households (thousands) [a,b]	9,895	10,183	10,363	10,558	10,716	10,900	11,069	11,224	11,385	11,553	11,729	11,897	12,052	12,214	12,375	12,587	27.2%
Energy Intensity (GJ/household) [a,b]	**19.9**	**18.9**	**18.8**	**18.1**	**17.8**	**17.3**	**17.3**	**17.2**	**16.8**	**16.6**	**16.7**	**16.9**	**16.4**	**16.6**	**16.9**	**16.1**	**-19.1%**

http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tableshandbook2/res_00_15_e.xls

Screen clipping taken: 04/08/2008, 8:13 AM

Domestic Hot Water

DHW energy consumption for new and existing appliances is improving steadily as a result of energy efficiency regulations. The minimum efficiency factor has risen from 0.52 for a 200 litre tank as of 1995 to 0.57 for a 200 litre tank as of 2003. (OEE Regulations Bulletin, Sept 2004). Over the study period, the natural turnover of water heaters will result in an improvement of approximately 2% as failing water heaters are replaced by new ones that meet the new standard. The UEC for DHW in new buildings is assumed to be constant.**

Table 2 is a summary of residential appliance unit energy consumption (UEC) for major appliances from 1990 to 2005.

Table 2

Natural Resources Canada | Ressources naturelles Canada

Canada

Residential Appliance Unit Energy Consumption (UEC)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total Growth 1990–2005
UEC [1] for New Electric Appliances (kWh/year) [a]																	
Refrigerator	956	931	902	720	650	642	640	657	654	645	640	559	506	487	478	469	-50.9%
Freezer	714	445	449	402	367	382	377	376	381	383	391	393	368	369	373	386	-46.0%
Dishwasher [2]	227	212	194	195	166	140	137	130	127	123	120	116	107	92	79	68	-70.0%
Clothes Washer [2]	97	96	94	88	79	77	76	74	72	69	67	65	62	57	46	35	-63.6%
Clothes Dryer	1,103	1,109	983	928	910	909	887	887	900	908	910	916	916	914	912	904	-18.0%
Range	772	778	779	782	774	771	774	772	771	759	760	763	756	718	653	573	-25.9%
UEC [1] for New Natural Gas Appliances (kWh/year) [b]																	
Clothes Dryer	925	912	906	903	896	889	880	880	880	880	880	880	880	880	880	880	-4.9%
Range	1,357	1,294	1,283	1,267	1,251	1,236	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	-9.7%
UEC [1] for Stock of Electric Appliances (kWh/year) [b]																	
Refrigerator	1,525	1,478	1,427	1,363	1,294	1,230	1,166	1,105	1,047	993	945	896	846	801	778	735	-51.8%
Freezer	1,291	1,250	1,206	1,157	1,108	1,056	1,004	948	886	825	767	713	661	614	572	535	-58.6%
Dishwasher [2]	282	274	255	247	236	222	208	194	182	170	159	149	139	129	118	111	-60.8%
Clothes Washer [2]	106	105	103	101	99	97	94	92	89	87	84	82	79	76	72	67	-36.5%
Clothes Dryer	1,314	1,293	1,265	1,233	1,200	1,171	1,141	1,112	1,087	1,063	1,042	1,022	1,004	988	973	959	-27.0%
Range	802	800	798	796	793	791	789	787	785	782	780	777	774	769	759	744	-7.2%
UEC [1] for Stock of Natural Gas Appliances (kWh/year) [b]																	
Clothes Dryer	1,468	1,398	1,314	1,228	1,156	1,100	1,050	1,010	979	955	938	925	914	906	900	895	-39.0%
Range	1,534	1,521	1,505	1,481	1,456	1,432	1,410	1,387	1,364	1,344	1,326	1,311	1,297	1,283	1,271	1,260	-17.9%

1) Unit energy consumption is based on rated efficiency.
2) Excludes hot water requirements.

Sources:
a) Special Tabulations from Canadian Appliance Manufacturers Association, Mississauga, December 2006.
b) Natural Resources Canada, Residential End-Use Model, Ottawa, June 2007.

1990-2005

http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tableshandbook2/res_00_16_e.xls

Screen clipping taken: 04/08/2008, 7:54 AM

Fireplaces

Fireplaces currently have a very wide range of efficiencies, and the average efficiency of units currently sold has not been extensively studied. The study team and industry personnel estimated that the base case efficiency of current fireplace unit sales is approximately 35-40%. In the absence of any new initiatives, the average UEC was not assumed to change during the study period. **

Pool Heaters

UEC for pool heaters is not expected to change during the study period in the absence of any new initiatives. **

Other

In the absence of any new initiatives, other gas uses (spas, barbecues, etc.) were not assumed to change during the study period. **

Furnaces

NRCan data shows in British Columbia there is a trend towards the use of more efficient furnaces in both new construction and replacement markets. High efficiency furnaces account for approximately 6% of furnace installations in new homes and the replacement market from 1990-2005; from a low of approximately 2% in 1990 to a high of approximately 10% in 2005. Medium and standard efficiencies furnaces accounted for approximately 8% and 40% respectively. The installation of standard efficiency furnaces is no longer permitted in the British Columbia marketplace.

Source;
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_21_e.xls

Discussions with British Columbia industry personnel indicate that mid-efficiency models are still being installed in a large number of new homes and in furnace replacement projects, even with the existence of the current incentives. Consequently, this Reference Case assumes that the trend towards increased market share of high efficiency furnaces continues over the study period, but at a moderate rate. This latter assumption recognizes that, by definition, this Reference Case does not include future Terasen Gas DSM programs. **

** (Data - BC Gas Residential End Use Survey Results)

Table 3 summarizes residential heating system stock by building type and heating system type from 1990 to 2005

Table 3

Natural Resources Canada | Ressources naturelles Canada | Canada

Residential Sector

Historical Database – June 2007

British Columbia

Table 21: Heating System Stock by Building Type and Heating System Type

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total Heating System Stock (thousands)	**1,280**	**1,297**	**1,345**	**1,364**	**1,406**	**1,471**	**1,504**	**1,568**	**1,585**	**1,604**	**1,624**	**1,647**	**1,671**	**1,696**	**1,718**	**1,754**
Heating System Stock by Building Type (thousands)																
Single Detached	751	757	781	788	808	841	855	887	892	899	907	918	930	942	951	969
Single Attached	109	113	120	124	130	139	144	152	156	160	164	169	174	179	183	189
Apartments	368	375	391	399	413	435	447	469	476	484	491	498	505	512	519	530
Mobile Homes	51	51	53	53	55	57	58	60	60	61	61	62	63	63	64	65
Shares (%)																
Single Detached	58.7	58.4	58.1	57.8	57.5	57.2	56.8	56.6	56.3	56.1	55.9	55.7	55.6	55.5	55.4	55.3
Single Attached	8.6	8.7	8.9	9.1	9.3	9.4	9.6	9.7	9.9	10.0	10.1	10.3	10.4	10.5	10.7	10.8
Apartments	28.8	28.9	29.1	29.2	29.4	29.6	29.7	29.9	30.0	30.2	30.2	30.2	30.2	30.2	30.2	30.2
Mobile Homes	4.0	3.9	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.8	3.8	3.8	3.7	3.7	3.7	3.7

27	***Heating System Stock by Heating System Type (thousands)***																
28	Heating Oil – Normal Efficiency	136	130	124	113	107	97	92	80	70	63	59	58	54	51	49	48
29	Heating Oil – Medium Efficiency	1	1	1	2	3	4	4	5	6	8	9	10	11	12	13	13
30	Heating Oil – High Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Natural Gas – Normal Efficiency	638	643	642	636	634	634	631	624	615	610	605	598	591	582	573	564
32	Natural Gas – Medium Efficiency	15	20	43	58	75	95	105	130	141	156	169	178	196	210	221	231
33	Natural Gas – High Efficiency	31	36	44	49	57	69	76	92	98	106	113	121	135	151	162	182
34	Electric Baseboard	307	319	345	360	383	422	443	463	471	472	474	478	473	473	475	486
35	Heat Pump	21	22	23	24	27	27	26	27	33	35	37	39	41	43	45	47
36	Other[1]	13	14	16	18	19	20	22	24	26	27	27	29	30	30	30	30
37	Wood	24	24	25	26	26	22	21	20	20	20	20	22	24	24	26	26
38	***Dual Systems***																
39	Wood/Electric	59	56	48	45	42	46	53	61	62	64	66	67	69	71	73	74
40	Wood/Heating Oil	22	21	21	17	16	18	20	24	24	25	26	26	27	28	28	29
41	Natural Gas/Electric	9	9	10	11	11	11	8	12	13	13	14	14	15	15	16	16
42	Heating Oil/Electric	3	3	3	7	7	7	2	5	6	6	6	6	7	7	7	8
43																	
44	***Shares (%)***																
45	Heating Oil – Normal Efficiency	10.6	10.0	9.2	8.3	7.6	6.6	6.1	5.1	4.4	3.9	3.6	3.5	3.2	3.0	2.9	2.7
46	Heating Oil – Medium Efficiency	0.0	0.1	0.1	0.1	0.2	0.3	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8
47	Heating Oil – High Efficiency	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Natural Gas – Normal Efficiency	49.9	49.6	47.7	46.6	45.1	43.1	42.0	39.8	38.8	38.0	37.2	36.3	35.4	34.3	33.4	32.1
49	Natural Gas – Medium Efficiency	1.2	1.5	3.2	4.2	5.4	6.5	7.0	8.3	8.9	9.7	10.4	10.8	11.7	12.4	12.9	13.2
50	Natural Gas – High Efficiency	2.5	2.8	3.3	3.6	4.1	4.7	5.1	5.8	6.2	6.6	7.0	7.3	8.1	8.9	9.4	10.4
51	Electric Baseboard	24.0	24.6	25.7	26.4	27.2	28.7	29.5	29.5	29.7	29.4	29.2	29.0	28.3	27.9	27.7	27.7
52	Heat Pump	1.7	1.7	1.7	1.8	1.9	1.8	1.7	1.7	2.1	2.2	2.3	2.4	2.4	2.5	2.6	2.7
53	Other[1]	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.7	1.7
54	Wood	1.9	1.9	1.8	1.9	1.9	1.5	1.4	1.3	1.3	1.2	1.2	1.4	1.4	1.4	1.5	1.5
55	***Dual Systems***																
56	Wood/Electric	4.6	4.3	3.6	3.3	3.0	3.1	3.5	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.2
57	Wood/Heating Oil	1.7	1.6	1.5	1.3	1.1	1.2	1.3	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6
58	Natural Gas/Electric	0.7	0.7	0.8	0.8	0.8	0.7	0.5	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
59	Heating Oil/Electric	0.2	0.2	0.2	0.5	0.5	0.5	0.1	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
60																	
61	1) "Other" includes coal and propane.																
62																	

1990-2005

http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_21_e.xls

Screen clipping taken: 04/08/2008, 8:26 AM

Table 4 supports the assumption that further heating system efficiencies will be relatively minor.

Table 4

Natural Resources Canada / Ressources naturelles Canada

Canada

Residential Sector

Historical Database – June 2007

British Columbia

Table 26: Heating System Stock Efficiencies

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Heating System Stock Efficiencies by System Type (%)																
Heating Oil – Normal Efficiency	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Heating Oil – Medium Efficiency	75	75	75	75	75	78	78	78	78	78	78	78	78	78	78	78
Heating Oil – High Efficiency	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Natural Gas – Normal Efficiency	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Natural Gas – Medium Efficiency	78	78	78	78	78	78	78	79	79	79	79	80	80	80	80	80
Natural Gas – High Efficiency	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Electric Baseboard	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Heat Pump	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Other[1]	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Wood	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Dual Heating Systems Electric/Wood																
Electricity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wood	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Dual Heating Systems Heating Oil/Wood																
Heating Oil	75	75	75	75	75	78	78	78	78	78	78	78	78	78	78	78
Wood	50	50	50	50	50	57	57	57	57	57	57	57	57	57	57	57

33	**Dual Heating Systems Electric/Natural Gas**																
34	Electricity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
35	Natural Gas	78	78	78	78	78	78	78	79	79	79	79	80	80	80	80	80
36																	
37	**Dual Heating Systems Electric/Heating Oil**																
38	Electricity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
39	Heating Oil	75	75	75	75	75	78	78	78	78	78	78	78	78	78	78	78
40																	
41	1) "Other" includes coal and propane.																
42																	

1990-2005

http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_26_e.xls
Screen clipping taken: 04/08/2008, 8:33 AM

43.0 Reference: Exhibit B-2, BCUC IR#1 68.1, Windows

43.1 Please provide specific support provided by Marbek that indicates that windows have a thirty year life, and in particular, that the sealed glass units have a thirty year life. Please list the warranties of surveyed manufacturers for both glass and frame.

Response:

The 30 year life estimate was provided by Marbek as part of the CPR project. The footnote in the report (“Terasen Gas Conservation Potential Review – Residential Sector Report”, April 2006, P55) notes that the data was derived from a study undertaken in Ontario in 2004 for Enbridge Gas.

No specific studies have been undertaken locally, but it should be noted that some major window manufacturers now offer lifetime warrantees with their windows.

44.0 Reference: Exhibit B-2, BCUC IR#1 69.1, Heat Pumps

44.1 The question asked for the payback for a heat pump along with efficiency assumptions and the calculation. It is not clear that this response pertains to a heat pump relative to a gas furnace with AC. Please respond to the original question in detail.

Response:

The initial analysis comparing a heat pump and a natural gas furnace with air conditioning is contained in the Conservation Potential Review as part of the analysis on Fuel Choice and is contained in Section 4.6.1. This analysis shows a lower capital cost of about $ 900 for a furnace and air conditioner.

The details of the initial CPR analysis are not available, and a subsequent analysis was undertaken by Terasen. It shows a higher capital cost of about $1,200 for a heat pump, and a payback to the home owner of about 7 years on this incremental cost.

Furnace / AC Cost Assumptions:

Natural Gas Furnace
Furnace- $ 3,000
Installation - $ 1,000
Consumption - 53 GJ / yr
Fan - 730 kWh / yr
Carbon Tax - $ 25 /yr
Maintenance - $ 150 / yr

Air Conditioner
Equipment - $ 4,000
Installation $ 1,800
Consumption - 1,330 kWh /yr
Maintenance - $ 250 /yr

Based on a cost for electricity of $ 0.07 per kWh and $11 per GJ, this yields a capital cost of $ 9,800 and an annual operating cost of $ 1,152.

Air Source Heat Pump Cost Assumptions
Heat pump - $ 9,000
Installation - $ 2,000
Consumption - 8,275 kWh / yr
Maintenance - $ 400 / yr

Based on the same cost assumptions, this yields a capital cost of $ 11,000 and an annual operating cost of $979.

The additional capital cost of the Heat Pump is $1,200 while the reduced operating cost is $ 173/yr for a payback on the additional cost of 6.9 years.

45.0 Reference: Exhibit B-2, Response to BCUC IR#1 71.1, "Impact of Terasen Gas / Energy Star Heating System Upgrade (2003) Program," August 2004 Habart Report

In Attachment 71.1, page 12 of the August 2004 Habart Report it shows the calculation of the direct annual energy savings to calculate the 12.6 GJ of energy savings based on 92% AFUE for a typical high efficiency gas furnace and the differential from the 78% AFUE minimum regulations of the Energy Efficiency Act.

45.1 Please identify the purchase availability of mid-efficiency furnaces at 78% AFUE.

<u>Response:</u>

Natural Resources Canada list of approved furnaces shows that between 6 manufacturers (Lennox, Trane, American Standard, Guardian, AirPro, and Coleman-Evcon) there are 57 different models available at 78% AFUE. There are also 34 models available between 78 and 80 AFUE.

http://www.oee.nrcan.gc.ca/energystar/english/consumers/gas-furnace-search.cfm?text=N&printview=N

45.2 Do purchasers of mid-efficiency purchases typically purchase an 80% AFUE furnace? If so, should the 12.6 GJ of incremental energy savings be calculated based on 80% AFUE since that is the base technology choice that the furnace buying customer makes?

<u>Response:</u>

Detailed information on sales figures are not available to Terasen however since many 78% AFUE furnaces are available for purchase then this is the lower end standard that should be used to calculate savings.

In retrofit application the replaced furnace will be as low as 64.5 AFUE (from 2008 ASHRAE Handbook, HVAC Systems and Equipment, Chapter 32, Furnaces. page 32.9, Table 1 Typical Values of Efficiency).

46.0 Reference: Exhibit B-2, BCUC IR#1 71.3

The table of Terasen's past programs suggests that the programs have existed for time periods ranging from a few months to a few years.

46.1 Have the Companies studied the potential impact of program length on the spillover effect? If so what were the findings? To what extent do the Companies believe that a program length of a few months can restrict the opportunity for spillover effects and therefore the potential benefit of the programs?

Response:

The Companies have not studied the potential impact of program length on spillover effect. As noted in Principle 11 on page 48 of Exhibit B-1, the Companies are proposing multi-year programs, so programs that are implemented pursuant to approval of this EEC Application would remain in the marketplace so long as they are successful (i.e. contribute to an overall Portfolio TRC of 1.0 or greater). While the tranche of funding being requested in this Application is to take the Companies to end of 2010, the Companies intend to apply to the Commission for the next tranche of EEC funding for 2011 and onward following the completion of an updated CPR in 2009, as outlined on page 50 of Exhibit B-1. If the CPR update finds that some of the programs introduced as a result of approval of Exhibit B-1 continue to offer the Companies customers opportunities to conserve, presumably those programs would continue to be offered in the marketplace, and so would have a program length of more than a few months, offering a good opportunity to capture energy savings from spillover effects.

The current Application is requesting program funding for three years, but the Companies have indicated that several program areas have not been designed in detail (e.g. Energy efficiency for commercial retrofits [IR#1 25.2]; Innovative Technologies, NGV and Measurement [IR#1 33.1]; Trades Training [IR#1 63.1]).

46.2 Can Terasen confirm that because programs that have not been planned in detail, the resulting time frame could be relatively short? To what extent, in Terasen's view might the potential short time frame of planned programs restrict spillover effects? To what extent has Terasen considered allowing an extended time frame for programs?

Response:

The Companies anticipate rolling out all programs three to six months following approval of the Application. As indicated in the response to BCUC IR 2.46.1 above, successful programs that still offer opportunities for energy savings would presumably continue in the next tranche of funding, for 2011 and beyond. This should offer opportunities to capture any potential spillover effects for successful programs.

47.0 Reference: Exhibit B-2, BCUC IR#1 71.4, and Exhibit B-1, Appendix 10, pp. 44-48

“Developing a monitoring and verification plan during the program design phase is critical as it ensures that the success of the program can be effectively measured. Frequently monitoring and assessing the progress of programs is also a best practice as it allows for mid-course changes to the programs if needed. (Ex. B-1, App.10, p. 45)”

47.1 Please explain whether Terasen would be able to satisfy all of the best practices described in Exhibit B-1, Appendix 10, pp.44-48, for monitoring, evaluation, and reporting, prior to an eventual proposal being brought forward by the BCPECE Evaluation working group.

Response:

It is the Companies view that it is best served by awaiting the proposal coming forward from the British Columbia Partnership for Energy Conservation and Efficiency Evaluation working group, which will draw upon the Indeco Best Practices study provided as Appendix 10 to Exhibit B-1 in making recommendations. Programs will be designed with monitoring, evaluation and reporting in mind, however, as recommended in BP14, on page 44 of Appendix 10 to Exhibit B-1, the Application.

48.0 Reference: Exhibit B-2, BCUC IR#1 73.4

48.1 Terasen states that: "Crossover effects from the impact of E* dishwashers on furnace loads were not considered, as the reduction in heat output from an E* dishwasher is unlikely to be of a sufficient magnitude to affect the thermostat controlling the furnace."

48.1.1 For gas hot water what is the monthly reduction in GJ and kW.h use for the efficient dishwasher?

Response:

As noted in "Terasen Gas CPR Measures Update" Appendix A, for the efficient dishwasher the annual electric savings are 147 MJ per year (approximately 41 kWh/yr) and 2,120 MJ of natural gas for hot water savings.

48.1.2 Does Terasen know if BC Hydro adjusts for cross over effects, and can it provide any quantification of these effects from BC Hydro?

Response:

Terasen Gas is not privy to BC Hydro's detailed program analysis including that of cross over effects.

48.2 The Companies' response to question 73.4 states that "HOT2000 indicates that internal heat gains offset primary space heating by a factor of 0.4."

By way of illustrating what it means to say that "internal heat gains (from the fireplace) offset primary space heating by a factor of 0.4," can Terasen provide an example using a 70% efficient fireplace and a 90% efficient furnace to show the incremental energy use arising from a 1 GJ input into the fireplace on an average heating season day.

Response:

The following is an example to illustrate the impact of a 1 GJ increase in consumption for a 70% efficient fireplace on the natural gas consumption of a 90% efficient furnace, assuming a 0.4 cross effects factor.

- Fireplace input energy - 1 GJ or 948,000 BTUs
- Fireplace output energy (heat) - 0.7 X 948,000 BTUs = 664,000 BTUs
- Furnace heat offset (Reduction in furnace output) - 0.4 X 664,000 BTUs = 265,000 BTUs
- Furnace input reduction - 265,000 / 0.90 = 295,000 BTUs or 0.31 GJ

Therefore, based on the given assumptions, a 1 GJ increase in natural gas to the fireplace will result in slightly less than 1/3 GJ reduction to the furnace.

48.3 Does Terasen have any evidence of the percentage of average fireplace use that occurs in the heating season versus the non-heating season? If so, what is that percentage?

Response:

Detailed information on hours of fireplace use by season was collected as part of the BC Gas Residential End User Survey Results in December 2003 by Habart & Associates. The following information is from section 3.3 page 16 of the survey.

Among respondents with a fireplace, the average hours of fireplace use by season were as follows: summer 0.6 hours per week; fall 10.1 hours per week; winter 20.8 hours per week; and spring 9.3 hours per week.

Weekly hours of fireplace operation by season by region (hours per week)

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	LM	Int.	BC Gas
Unweighted base	215	267	261	267	249	743	516	1259
Summer	0.39	0.66	0.31	0.51	1.09	0.43	0.85	0.56
Fall	8.38	7.37	13.28	11.37	8.64	10.17	9.77	10.06
Winter	14.88	15.62	25.38	32.31	18.75	19.62	24.35	20.83
Spring	5.95	7.24	14.16	9.30	7.77	9.72	8.38	9.34

Percentage of fireplace operation per week by season by region
(Calculated from the above table)

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	LM	Int.	BC Gas
Summer	0.2%	0.4%	0.2%	0.3%	0.6%	0.3%	0.5%	0.3%
Fall	5.0%	4.4%	7.9%	6.8%	5.1%	6.1%	5.8%	6.0%
Winter	8.9%	9.3%	15.1%	19.2%	11.2%	11.7%	14.5%	12.4%
Spring	3.5%	4.3%	8.4%	5.5%	4.6%	5.8%	5.0%	5.6%

Zone 1—Vancouver, Richmond, North and West Vancouver

Zone 2—Burnaby, New Westminster, Coquitlam, Port Coquitlam, Port Moody

Zone 3—Pit Meadows, Maple Ridge, Mission, Delta, Surrey, White Rock, Langley, Abbotsford, Chilliwack, Harrison, Hope

Zone 4—West and East Kootenays

Zone 5—Central and Northern Interior

LM—Zones 1-3

Int.—Zones 4&5

49.0 Reference: Exhibit B-2, BCUC IR#1 73.1, 74.1, and 75.1

49.1 Please provide working Excel spreadsheets versions of the tables provided in response to Information Request No. 1 questions 73.1, 74.1 and 75.1.

Response:

Due to the commercial sensitivity of the information requested, the response to this question has been filed under separate cover in accordance with the BCUC Practice Directive pursuant to Section 13 of the *Administrative Tribunals Act* related to Confidential Filings. The Terasen Utilities have requested that the information be made accessible only to the Commission and to those authorized representatives of Registered Intervenors who execute an undertaking, consistent with Attachment A to the BCUC Practice Directive, to hold the information confidential.

50.0 Reference: Exhibit B-2, BCUC IR#1 75.5, Cross Over Impacts with Power Smart

50.1 Terasen acknowledges that there will be crossover effects when (for instance) a Power Smart lighting program causes the natural gas heat source to provide more output, but that this is exogenous to the Conservation programs. Does Terasen know if BC Hydro accounts for these effects when designing its programs?

Response:

As noted in 48.1.2, Terasen Gas is not privy to how BC Hydro accounts for these effects when designing and analyzing programs.

51.0 Reference: Exhibit B-2, BCUC IR#1 77.1, Overlap

51.1 Terasen states that the BCPECE will ensure that there is no program overlap and that that this should provide reasonable assurance to the Commission. If the BCPECE does not provide guidance prior to a decision being rendered in this matter, how should the Commission proceed?

Response:

The Commission should approve the EEC Application as written, and should not await guidance from BCPECE, as the Companies have a track record of good collaboration with other entities on delivering EEC activities. Further, the work of the Steering Committee (on which Commission staff participate as a member) and of the Built Environment Working Group for BCPECE, are ongoing efforts with regular meetings, therefore the Companies anticipate that the Commission should remain aware of the activities of the BCPECE. Particularly in the case of the Built Environment Working Group, specific programs will be discussed, and opportunities for collaboration and cooperation explored. Presumably if an issue arose where there was material program overlap, those concerns could be addressed at the BCPECE table. The Terms of Reference for the BCPECE are provided as Attachment 51.1.

51.2 Will the BCPECE have enforcement powers?

Response:

The Companies are unaware of any plans to give BCPECE enforcement powers.

51.3 Will the BCPECE make rules on inter-utility cross over effects?

Response:

The BCPECE Terms of Reference are included in the response to BCUC IR 2.51.1, Attachment 51.1. Item #4 in the Steering Committee Projects list states:

> *"Define how to allocate ownership of, or credit for, energy conservation and GHG reduction achievements across utilities and other stakeholders if applicable."*

Presumably this work would encompass cross-over effects.

52.0 Reference: Exhibit B-2, BCUC IR#1 78.3, Incentives

Terasen states:

> Basic economics would suggest that, if the incentive was higher, more customers are likely to participate. While the higher incentive does not affect the TRC (as the incentive is a transfer payment between the utility and the program participant), it does increase the cost to the utility, and hence would affect the RIM test. For example, if the incentive for the furnace retrofit program is increased from 50% to 100%, the RIM drops from 0.5 to 0.4. Similarly, if the Commercial near condensing boiler program incentive is similarly increased, the RIM drops from 0.6 to 0.5.

52.1 Isn't it likely that when the incentive increases more customers will participate and since there are likely economies of scale in administration that the TRC will actually improve?

Response:

The balance of the response to BCUC IR1.78.3 noted *"However, it is not clear how many additional customers the higher incentive would attract. In the business sector, decisions are often made based on the payback for the investment, with a 2 year payback considered a common threshold. If the incentive is increased so that the investment now yields a 1 year payback, it is not clear how many more customers would be attracted."*

That said, it is certainly possible that a higher incentive would cause higher participation levels and that these higher participation levels could increase TRC. However, in cases where the Companies' administration costs are on a "per participant" basis, it should not be assumed that there are automatically economies of scale in administration costs that would increase TRC.

52.2 Since the TRC will stay the same or increase as incentives increase, and higher incentives will result in higher DSM, and the Province wishes to pursue all cost effective DSM, and Terasen states cost effectiveness is driven by the resource cost, why hasn't Terasen suggested incentive levels of 100 percent of incremental cost, or even the full capital cost of the EEC measure?

Response:

As noted in the response to BCUC IR 2.52.1 above, price is only one of the barriers to increasing program participation, and it is not clear that increasing incentives above the level of providing reasonable economics to participants will have a commensurate impact on participation. However such an increase will have an impact on the RIM test, or the costs to non-participants as noted in the response to BCUC IR 1.78.3.

Terasen Gas has a responsibility to all its customers to temper rate increases, and hence, will try to balance the benefits of increasing energy savings from DSM activity with the rate impacts, based in part on input and guidance from the Stakeholder Group proposed in Section 6.14.2 of Exhibit B-1.

53.0 Reference: Exhibit B-2, BCUC IR#1 79.1, Participant Benefits

53.1 What is the participant benefit ratio (1) assuming the fuel substitution program exists and (2) in the absence of the program and its incentives (i.e. what would be the benefits and cost to the customer without receiving any incentives)?

Response:

In response to part (1) of the above IR, participant benefit ratios for all measures and programs, including fuel switching, can be viewed in the Attachment 56.2 filed in response to BCUC IR 1.56.2.

In response to part (2) of the above IR, the Participant test is one of the Economic Tests outlined for DSM programs in the California Standard Practice Manual. Since part (2) of the I.R. asks about a scenario where there is no DSM program, it is not appropriate to apply a DSM Economic Test to a scenario in which there is no DSM program. A more appropriate Economic Test might be Simple Payback, and Simple Paybacks for all measures, including fuel switching, can be found in Appendix A to Appendix 9 of Exhibit B-1. It should be noted that the Simple Paybacks in the above-referenced document are economic only, and do not account for non-energy benefits such as faster recovery times for gas water heaters, and more immediate and accurate temperature control for gas ranges.

54.0 Reference: Exhibit B-2, BCUC IR#1 80.1, TRC

54.1 Please demonstrate the response to your question by preparing in a table by program, the costs and benefits that comprise the TRC calculation, the ratios for the program components and the sectors, and in total. Indicate how each total and subtotal is calculated.

Response:

The table presented in Exhibit B-2 response to BCUC IR#1 80.2 is expanded in Attachment 54.1 to show the TRC Benefit/Cost and Net Benefits columns. The calculations are as follows:

1. TRC Benefits equal the sum of the Program Utility and Alternate Utility benefits.

2. TRC Costs equal the sum of the Utility and Customer costs.

3. For Energy Efficiency programs, the calculation is straightforward: TRC Benefits divided by TRC Costs is the Benefit/Cost ratio; TRC Benefits less TRC Costs is the Net TRC Benefits.

4. For Fuel Substitution programs, TRC Benefits are the Alternate Utility benefits. The Program Utility benefits are negative, reflecting the cost of gas purchased to supply the new load, and therefore are treated as a cost. So TRC Benefit/Cost ratio is equal to the Alternate Utility benefits divided by the sum of the total program costs plus the cost of purchased gas. The TRC Net Benefits are the Alternate Utility benefits less the total program costs plus the cost of purchased gas.

55.0 Reference: Exhibit B-2, BCUC IR#1 82.1, RIM

55.1 Please provide the studies upon which your expert consultant relied in order to conclude that a RIM of 0.6 is typical. What RIM is typical for BC Hydro and FortisBC DSM programs?

Response:

The statement in question likely comes from the Summary section of the report "Review of Conservation Potential" and is found on P25. The relevant section reads "These programs may provide some upward pressure on rates, as the ratepayer impact ratio is 0.6:1. However this is typical for DSM programs." This is perhaps imprecise English, as the statement intended to convey that ". . . upward pressure on rates . . " was typical, rather than a RIM of 0.6 was typical.

However RIM values of less than 1 (and hence possible upward pressure on rates) is typical of DSM programs for Residential and Commercial customers. Following is a summary of recent program RIM benefit / cost ratio's for both FortisBC and BC Hydro.

FortisBC

Sector	Program	RIM
Residential	Heat Pumps	0.6
	New Home Program	0.6
	Residential Lighting	0.9
	Home Improvements Program	0.5
Average		0.6
General Service	Lighting	0.6
	Building and Process Improvements	0.5
Average		0.6

Source: FortisBC Inc's Semi Annual Demand Side Management Report June 4, 2008

As can be seen, the average RIM for FortisBC's programs in the residential and general service categories is 0.6.

BC Hydro – Power Smart

Sector	Program	2005 REAP	2008 LTAP
Residential	New Home	0.8	1.1
	Renovation Rebate	0.8	0.8
	Variable Speed Motors	0.7	
	Fuel Substitution	0.8	
	Refrigerator Buy-back	0.6	0.9
	SLED	0.7	
	CFL	0.7	1.2
	Behaviour		0.8
	Voltage Optimization		0.9
	Sustainable Community		1.2
	Low Income		0.6
	Appliance and electronics		0.8
Average		0.7	0.8
Commercial	PS Partners	0.8	0.8
	Schools, universities etc.	0.7	
	Traffic Light	0.6	
	Product Incentive	0.8	0.8
	Lighting Redesign	0.7	
	Small Business CLF	0.7	
	High Performance Buildings	0.9	0.9
	Voltage Optimization		0.9
	Sustainable Community		1.1
Average		0.8	0.8

Source: BC Hydro 2005 REAP – Appendix A – Table 9
BC Hydro 2008 LTAP – Appendix K, Sub-Appendix C – Table 9

56.0 Reference: Exhibits E-1 to E-3; E-6 to E-11, E-13

56.1 Please provide copies of communications to stakeholders requesting support of the application including copies of any letter 'templates' provided to stakeholders.

Response:

Communications to stakeholders were made by the Companies' staff by telephone and email, and in face to face meetings. Three sample emails are included in Attachment 56.1. Stakeholders were provided with documentation concerning the EEC Application, instructions as to how to comment or intervene, and a template letter provided to stakeholders to use as a starting point for comment are also provided in Attachment 56.1.

56.2 Does Terasen provide financial support or sponsorship to any of those stakeholders commenting on the Application? If so which ones?

Response:

The table below provides detail as to the nature of any financial contribution by the Companies in 2008 to any of the stakeholders that had commented on the Application to August 13, 2008, the date this response was prepared. The Companies would like to make it clear that these are independent stakeholders who have made a decision to support or not to support the EEC Application based on their own consideration of its merits. It must be noted that in no cases do the Companies contribute to the ongoing operating expenses of stakeholders commenting on the Application, with the exception of those Registered Intervenors whose activities on specific applications or regulatory review proceedings the Commission has approved and subsequently issued orders to the Companies to provide Participant Assistance/Cost Awards. In all other cases, the Companies' financial involvement with commenting stakeholders is based upon:

- membership dues paid to belong to an organization;
- sponsorship of either specific events mounted by those organizations, and aimed at either the general public, the business community or those organizations' membership; or
- DSM program partnership.

Organization Name	Financial Support Provided in 2008
City Green	None
Ministry of Energy, Mines and Petroleum Resources	None
CMHC	None
Canadian Home Builders' Association	Member, sponsor of first time homebuyers' seminars and renovation seminars aimed at the general public, mounted by CHBA; sponsor of CHBA golf tournament
Hearth Patio and BBQ Association of Canada	Member of association; board member; Enerchoice fireplace program partner
Fraser Basin Council	None
Urban Development Institution	Member, sponsor of various events mounted by UDI, aimed at UDI membership of builders, developers and planners
Fraser Valley Homebuilders' Association	Member, sponsor of various events mounted by FVHBA, aimed at FVHBA membership of builders and developers
Natural Resources Canada	None
City of Nanaimo	None
City of Langford	None
Village of Cumberland	None
City of North Vancouver	None
District of West Vancouver	None
Brook and Associates	None
City of Powell River	None
Corporation of Delta	None
Lighthouse	Sponsor of speaker from Lighthouse at conference
Pacific Resource Conservation Society	Destination Conservation program partner
Canadian Manufacturers and Exporters	None
City of Victoria	None
Town of Ladysmith	None

Attachment 8.1

U.S. Electric Utility Demand-Side Management: Trends and Analysis

Introduction

Growing competition in the electric power industry is raising questions regarding the future of utility demand-side management (DSM) programs. This article[1] addresses changes in the growth and character of electric utility DSM and how growing competition and the imminent restructuring of the electric power industry may affect utility DSM practices.

From 1989 through 1993, data collected by the Energy Information Administration (EIA) showed a steady increase in utility DSM spending and in energy and demand savings. The most recent data collected (1994) show that the industry is reducing DSM spending and experiencing a reduction in the rate of growth in energy savings. In 1994, utilities reported modest reductions in energy savings and potential peak reductions. However, utility projections for 1995 show approximately a 40-percent reduction in the growth of energy savings and lower potential peak load reduc tions from DSM programs.

Among other factors, the potential for restructuring in the electric power industry could affect utilities' interest in energy savings. In a deregulated market for genera tion services, vertically integrated utilities will have an interest in selling more energy at higher prices. DSM programs that reduce consumption may place down ward pressure on prices. Restructuring also may create new types of DSM activities. A growing number of utilities are experimenting with two-way communi cation systems that provide customers flexible time-of-use or real-time pricing and energy information services.

Background

The Development of Utility DSM

Electric utility DSM refers to programs implemented by utilities to modify customer load profiles. Such programs have a variety of objectives.

- Energy-efficiency programs reduce energy use, both during peak and off-peak periods, typically without affecting the quality of services provided. Such programs substitute technologically more advanced equipment to produce the same (or a higher) level of end-use services (e.g., lighting, heating, cooling, drive power, or building shell) with less electricity.
- Peak load reduction programs focus on reducing load during periods of peak power consumption on a utility's system or in selected areas of the transmission and distribution grid. This category

includes interruptible load tariffs, time-of-use rates, direct load control, and other load management programs.

- Load shape flexibility can be achieved by programs that modify prices, cycle equipment, or interrupt service in response to specific changes in power costs or resource availability. These approaches include real-time pricing and time-of-use rates for pricing periods that have flexible hours. They also may include interruptible load tariffs, direct load control, and other load management programs when those activities are not limited to peak load periods.
- Load building programs are designed to increase use of electrical equipment or shift electricity consumption from peak to off-peak hours thereby increasing total electricity sales. This category includes valley filling programs that increase load during off-peak periods and programs that introduce new electric technologies and processes.

The Public Utility Regulatory Policies Act of 1978 (PURPA) identified and helped to focus attention on the benefits of “increased conservation of electric energy” and “load management techniques.”[2] A series of studies over the last 18 years identified and quantified a large potential to increase the efficiency of energy use.[3] Responding to this potential, State regulators supported and utilities implemented rebate and other DSM programs. Many DSM programs areviewed as resources because they capture cost-effective energy savings that would not otherwise be achieved. Most DSM programs are planned in an integrated resource planning (IRP) framework in which utilities compare the benefits and costs of DSM with the cost of additional generation. Utility IRP’s are subject to State regulatory review. Approximately half of the State regulatory commissions seek to reduce disincentives to utilities implementing DSM programs that result from conventional rate design practices. Given conventional rate designs, volumetric rates often are set above utilities’ short-run marginal costs.[4] As a result, when utilities lose potential sales as a result of consumers using energy more efficiently, revenues and profits go down. State commissions address this problem by using: (1) net lost revenue adjustment mechanisms that allow utilities to recover revenues lost as a result of conservation programs net of any cost savings; (2) revenue decoupling that separates utilities’ profit ability from the levels of actual sales; or (3) DSM performance incentives that are paid to utilities based on the savings achieved[5] (Figure FE1).

Electric energy savings and load reductions cannot actually be measured by metering and therefore must be estimated. Utilities report estimates of energy sav ings and peak load reductions based on engineering methodologies, statistical analysis of energy usage, and/or other estimation techniques. The estimated en ergy effects are subject to subsequent verification, as required by many State public service commissions. An EIA report[6] concluded that while estimated savingsin some cases exceeded subsequently verified results, a large variance between estimated and verified savings was not found. The estimated data on DSM programs are reported to EIA annually on Schedule V, “Demand-Side Management Information,” of the Form EIA-861, “Annual Electric Utility Report.” For reporting purposes, DSM programs are categorized as energy efficiency, direct load control, interruptible load, other load management, other DSM programs, or load-building activities. Large utilities[7] report for each program category and customer class estimated data for:

- **Incremental energy effects and incremental peak load reductions**—the effects caused by new program participants and new DSM programs during a given year. Incremental effects are "annualized"; that is, they are reported as if they were in effect for the entire year.

- **Current and projected annual energy effects and peak load reductions**—the total effects and peak load reductions caused by all participants (new and existing) in all DSM programs (new and existing) that are in effect during a given year. This includes the energy effects caused by programs initiated in prior years that are still in effect and programs that were terminated, but are still producing energy effects and/or peak load reductions. These data are reported for the reporting year, next year, and fifth year following the reporting year.
- **Current and projected annual costs**—the costs of DSM programs for the reporting year, the next year, and fifth year following the reporting year.

In addition, the type of energy-efficiency end-uses and programs offered in each customer class are collected.

From 1989 through 1993, utility DSM programs ex hibited steady or accelerating growth in energy savings and utility expenditures (Figure FE2). The largest share of utility expenditures and energy savings was associated with energy-efficiency programs. These programs supplied substantial peak load reductions, although large potential peak load reductions also occurred as a result of interruptible load programs.

Competition in the Electric Power Industry

Growing competition is becoming a major influence in the generation segment of the electric power industry. By the early 1990's, the exhaustion of economies-of-scale for large baseload generation,[9] efficient modular generation technologies (particularly combined-cycle units and aero-derivative turbines), low natural gas prices, and emerging information and control technologies began to make competition possible. Changing regulatory policies facilitated competition among generation suppliers. By the end of 1992, competitive bidding for new power supplies was approved in 20 States and was under consideration in 9 others.[10] Also, the Federal Energy Regulatory Commission (FERC) approved "market-based" pricing for some wholesale power sales,[11] and Congress broadened the scope of wholesale competition with the passage of the Energy Policy Act of 1992 (EPACT).[12] From 1989 to 1993, the number of qualifying facilities and other independent power production facilities (5 megawatts or more nameplate capacity) increased from 825 to 1,341, and their installed generating capacity increased from 36.6 to 59.1 gigawatts.[13] In 1992, for the first time, generating capacity added by independent power producers exceeded capacity added by traditional electric utilities.[14]

Within this context of technological and regulatory change, proposals are being made by the members of the industry, regulators, and consumers to restructure the industry, potentially deregulating generation and allowing retail customers access to competitive generation markets. Three factors contribute significantly to the consideration of restructuring:

- *Demand, primarily by industrial and large commercial customers, for lower prices and retail access:* Differentials between embedded generation costs and wholesale spot prices for generation create the perception that consumer prices can be lower if customers gain access to wholesale power markets. Figure FE3 provides a comparison of the generating costs embedded in utility rates (highest cost utility, regional average, and least cost utility) and wholesale peak period spot prices for selected North American Electric Reliability Council regions.[15] For most utilities, the embedded cost of generation that is built into their rates exceeds the wholesale spot price.[16] Moreover, within any given region, there are significant differentials between the generation costs of high and low cost utilities. These differentials do not imply that utilities have been imprudent, but they do contribute to the per ception that retail prices include uneconomic generation costs.
- *Implementation of the Energy Policy Act of 1992:* EPACT provided Federal regulators the authority to order utilities to provide transmission access for the purpose of facilitating competition in wholesale power markets. FERC's implementation of EPACT is illustrated by (1) its expansive notice of proposed rulemaking on wholesale competition;[17] (2) its transmission access and pricing policy statement establishing a "golden rule" of comparability between transmission pricing for a utility's own sales and transmission pricing for third parties;[18] (3) its Notice of Proposed Rulemaking on Stranded Costs which addresses the treatment of historically incurred costs that cannot be recovered at market prices;[19] (4) its encouragement for the formation of regional transmission groups; and (5) its require ment that transmission utilities, power pools, or electric reliability councils submit data on their transmission capabilities.[20]
- *The perception that competitive generation markets can work and produce economic efficiency benefits:* Interest in electric industry restructuring is supported by the successful privatization or restructuring of electric utilities in the United Kingdom, Norway, New Zealand, Australia, Chile, and Argentina,[21] and the relative success of restructuring in the natural gas, telecommunications, and other U.S. industries.[22]

Electric industry restructuring is currently receiving active legislative or regulatory consideration in approximately three-quarters of the States.[23] The consideration of restructuring is focused on competition in the generation portion of the electric power industry. A retail access plan was approved by the California Public Utilities Commission. Modest retail wheeling experiments, in which large customers will be able to purchase generation services directly from competitive generation suppliers, were approved in Michigan and New Hampshire.

Full retail competition will mean that consumers may choose their generation suppliers and that there will be competition in generation services, in financial contracts used to hedge the risk of future volatility in generation prices, and perhaps in certain services related to coordinating the operation of generating units. Electric distribution, transmission, and at least certain dispatch and coordination services historically have been and will continue to be regulated.

Distinguishing functions of the industry in which there will be competition from those in which competition will be limited is important to understanding the potential opportunities for DSM in a restructured electric power industry. If restructuring proceeds, energy-efficiency incentive programs could be supported through non-bypassable charges paid by the customers of regulated transmission and distribution companies. Other DSM services could be paid for by participating customers and provided by competitive energy service companies or packaged with generation and financial services by competing power marketers. The packaging of energy management, generation, and financial hedging services might emerge as the basis for an independent retail business involving new participants in a competitive retail access market structure. However, this article will examine the narrower issue of impacts on electric utility DSM activity.

Trends in Utility DSM

The latest data on DSM activities filed by electric utilities on Form EIA-861 are for 1994. Those filings also provided projected data for 1995 and 1999 for large utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours (MWh). Additionally, several utilities provided qualitative information on how increasing competition in the electric power industry is affecting their DSM programs.

The 1994 Program Year

Data compiled from responses on Form EIA-861 revealed moderate changes in utility DSM activity during the 1994 program year. Incremental energy savings decreased 8.4 percent from the 1993 level of 8,980 million kilowatthours (kWh) to 8,229 million kWh in 1994. Incremental potential peak load reductions decreased 17 percent from 7,137 megawatts (MW) in 1993 to 5,904 MW in 1994.[24] For the first time since EIA began tracking DSM activity, utility DSM expenditures decreased approximately 1 percent from $2.74 billion in 1993 to $2.72 billion in 1994. In 1993, utilities projected that 1994 DSM spending would exceed $3 billion.

A portion of the decreases in incremental energy savings and potential peak load reductions was anticipated in the utilities' 1993 projections of 1994 annual energy effects and peak load reductions. Annual energy savings in 1994 were 52,483 million kWh. In 1993, utilities projected 1994 annual energy savings of 52,655 million kWh. Annual potential peak load reductions in 1994 were 42,917 MW, exceeding the utilities' projections for 1994 of 42,220 MW. 1994 energy effects approached or exceeded the 1993 projections for 1994, suggesting that the reported decreases in incremental energy effects and peak load reductions represent a change in DSM activity, and are not the result of program evaluations completed since the filing of the prior year's Form EIA-861 data.

Most of the decreases in incremental energy savings occurred in energy-efficiency programs. However, all other program categories showed large percentage decreases in incremental energy savings. Interruptible load programs had the largest decreases in incremental potential peak load reductions, and percentage decreases in incremental potential peak load reductions also occurred in interruptible load, direct load control, and other load management programs. Other DSM programs showed an increase in incremental potential peak load reductions (Figure FE1)

Energy-efficiency programs accounted for 70.6 percent of direct DSM spending in 1994. The 1994 data continue to indicate that the cost to utilities of most energy-efficiency programs is competitive with or below the cost of new generating capacity. The cost of conserved energy in cents per kWh saved is a convenient index for making approximate comparisons between the cost of energy-efficiency programs and generic supply-side resources. The cost of conserved energy is the average life cycle cost of an efficiency measure or program expressed in cents per kWh saved over the life of the measures installed. Figure FE4 presents the average cost per kWh saved for the energy-efficiency programs of large utilities.[25]

The DSM programs of 63 percent of reporting utilities had average costs of conserved energy under 3 cents per kWh (Figure FE4).

The modest reductions in 1994 DSM savings and expenditures might be explained by the fact that interest in restructuring accelerated rapidly after the issuance of the California Blue Book in April 1994, one of the first proposals for deregulation of generation and significant retail access.[26] By April, many utilities had already set DSM program budgets for 1994. The full impact of concerns about restructuring on DSM activity may be observed first in data for the 1995 program year.

Table FE1. Incremental Energy Effects and Potential Peak Load Reductions by Program Type

Program Type	**Incremental Energy Savings** (Gwh/Year)		**Change In Incremental Energy Savings** (percent)	**Incremental Potential Peak Load Reductions** (MW)		**Change In Incremental Potential Peak Load Reductions** (percent)
	1993	1994	1993-1994	1993	1994	1993-1994
Energy Efficiency__	8,472	8,054	-5	1,839	1,751	-5

Direct Load Control	25	15	-40	1,297	884	-32
Interruptible Load	75	12	-84	3,536	2,822	-20
Other Load Management	19	7	-63	371	282	-24
Other DSM__	389	141	-64	94	165	+76
Total	**8,980**	**8,229**	**-8**	**7,137**	**5,904**	**-17**
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."						

Projections for the 1995 Program Year

The utilities' projections of annual energy effects and peak load reductions for 1995 suggest that substantial reductions in DSM activity could be under way (Figure FE5). There are, however, some important caveats re garding the reported data. Large utilities are asked to report projected annual energy savings, annual peak load reductions, and program costs for 1995 and 1999. "Annual effects" for 1995 and 1999 represent the continuing impacts of past, current, and projected years' participation in DSM programs. Year-to-year changes in annual effects can approximate mod ifications in DSM programs, though they may be influenced by factors unrelated to DSM activity for that year (i.e., large customers going out of business, revisions as the result of evaluation of DSM programs, or economic factors). Utilities currently do not report projected incremental effects, which would more closely track the impacts of planned DSM activity occurring in the year that the data are reported.

Annual energy savings in 1995 are projected to equal 52,831 million kWh per year, 0.7 percent above the annual energy savings reported for 1994. Annual 1995 potential peak load reductions are projected to decline by 2.6 percent from 1994 levels to 41,784 MW.The projections of annual effects represent the cumula tive impacts of all prior DSM activity and new activity in 1995. The stagnation of annual effects in 1995 is a major departure from the year-to-year growth reported in prior years.

The reduced growth in annual effects is partially attrib utable to the reporting practices of utilities. Significant declines in annual energy savings from 1994 to 1995 were noted on a number of individual utility reports. This was unexpected because "annual" energy savings reflect the cumulative effects of prior program years. These utilities were contacted for clarification of their reported data. In some cases, utilities had stopped in cluding annual energy savings of measures that remained in place, but were installed under DSM programs that were terminated. The extent of this under-reporting of annual energy savings for 1995 could be as great as 3,500 million kWh. Even assuming under-reporting of this magnitude, the rate of growth in annual energy savings in 1995 would decline by 40 percent. Utilities that reported significant decreases in potential peak load reductions also were contacted. Under-reporting of the continuing effects of terminated energy-efficiency programs had a much smaller impact on potential peak load reductions. Even after cor recting for possible under-reporting, potential peak load reductions declined in 1995. The remaining decreases in growth of annual effects after adjusting for reporting issues suggest that when 1995 data are reported later this year, significant decreases may be observed in incremental energy savings and peak load reductions.

DSM spending is projected to fall at a much slower rate than the growth in annual energy and peak load effects. DSM spending for 1995 is projected to decline from 1994 levels by 4.5 percent to $2.6 billion. This modest decline suggests that utilities are retaining the capa bility to implement DSM programs. Another possible explanation is that DSM budgets are perhaps being reassigned to customer service functions that are as of yet not clearly defined.

Annual energy savings from energy-efficiency pro grams are projected to continue growing, although at a slower rate, from 49,720 million kWh per year in 1994 to 51,221 million kWh in 1995. The reductions in DSM are not limited to energy-efficiency programs. Annual peak load reductions from energy-efficiency programs are expected to increase from 11,662 MW to 11,731 MW. For interruptible load programs and other DSM, utilities project reductions in annual peak load and energy effects in 1995. For direct load control programs, decreased potential peak load reductions are projected for 1995 (Figure FE6) and (Figure FE7).

These findings show a greater decline in energy savings and peak load reductions than suggested by an earlier study.[27] The study projected that the 1994 to 1998 decline in the rate of growth of cumulative energy savings would be less dramatic than the decline in DSM expenditures and that the growth in cumulative peak load reductions would come closer to matching recent historical experience. The study, completed in early 1995, relied on a smaller survey of 37 selected utilities and 22 State regulatory commissions. Each of the 37 utilities included in the survey spent at least $5 million on DSM in 1994, making them among the largest in the industry. The study did not regard the sample as representative of all U.S. utilities.

Possible explanations for a decline in DSM activity in 1995, supported by the qualitative data provided by electric utilities, include:

- Low avoided costs may make some DSM options no longer cost-effective. This explanation is con sistent with the increase in annual effects that is projected for 1999, when some utilities will require additional capacity.
- To reduce rate impacts of DSM programs, utilities may be lowering energy savings targets or placing more emphasis on benefit/cost tests that measure rate impacts, as opposed to reductions in customer or societal costs. For many utilities, negative rate impacts are primarily the result of

revenue losses created by existing rate design practices whenever sales decline.

- Some utilities report that they are shifting from rebate, low-cost loans, and other financial incen tive programs to information and conventional financial programs. Information and conventional financing programs simply may be less effective than rebate and financial incentive programs in achieving savings over and above the savings that naturally occur in the absence of DSM programs.

The annual effects projected for 1995 raise serious questions about utilities' commitments to cost-effective DSM opportunities. In a qualitative assessment of the impact of increasing competition on their DSM programs, several utilities suggested that, to date, competition is having little or no impact on their current DSM activities. Other utilities indicated that programs were being cut and that they were reducing or eliminating programs that incorporated rebates or other financial incentives. Additional data collection and analysis are needed to fully explain the decline in the growth of annual effects projected for 1995.

Projections for the 1999 Program Year

Year-to-year growth in annual effects is predicted by electric utilities to rebound to some extent by 1999. Projections exhibit growth in both annual energy savings and annual potential peak load reductions, compared with 1994 and 1995. This may reflect that some utilities are approaching the time when new capacity will be required.

The projected growth in annual energy savings is open to question, however, because of possible under-reporting of energy savings from terminated DSM programs. It is difficult to estimate to what extent under-reporting affects 1999 data, given that some previously installed measures may reach the end of their useful lives between 1995 and 1999. To the extent under-reporting had a greater impact on 1995 than on 1999 projections, the represented data may overstate the average annual 1995 to 1999 rate of growth in annual energy savings. As was the case for 1995, only projected "annual effects" data are available to represent 1999 energy savings and peak load reductions.

Utilities projected 1999 annual energy savings of 71,883 million kWh per year and potential peak load reductions of 51,487 MW. This represents an 8.0 percent average annual rate of growth in energy savings, and a 5.4 percent average annual rate of growth in potential peak load reductions from reported 1995 levels. These projections are lower than the projections made by the same utilities in 1993 for 1998 energy savings (88,978 million kWh in 1998) and potential peak load reductions (55,163 MW in 1998). Projected annual energy savings for energy-efficiency programs increased from 51,221 million kWh for 1995 to 69,825 million kWh for 1999.

DSM spending is projected to continue to decline, from $2.6 billion in 1995 to $2.5 billion in 1999. During the same period, utilities project a 13-percent reduction in direct utility expenditures on energy-efficiency programs.

The electric power industry has entered a period of rapid change. Predicting DSM effects 5 years into the future can be difficult. The extent to which changes have been fully or accurately anticipated by utilities in their 1999 DSM projections can be uncertain.

Summary of DSM Trends 1994 to 1999

The major trends in DSM data reported on Form EIA-861 for 1994 are:

- In 1994, utilities experienced moderate reductions in DSM activity.
- For 1995, utilities projected substantial reductions in the growth of annual energy savings and lower potential peak load reductions. These reductions are partially explained by data reporting issues.
- Although energy savings and peak load reductions from energy-efficiency programs were impacted, other types of DSM programs were affected to a comparable or greater extent by reductions in DSM activity in 1994 and reductions projected for 1995.
- DSM spending is projected to decline moderately, suggesting that utilities intend to retain a DSM capability.
- Utilities are projecting growth in annual energy savings and annual potential peak load reductions for 1999, although that growth will be at a more modest rate than over the last 5 years.

The Effects of Competition and

Restructuring on Utility DSM

The restructuring of the electric power industry may change electric utility DSM. Utilities that anticipate little growth in the use of DSM resources attribute this to increasing competition in the electric power industry.[28] The fundamental characteristics of a restructured industry are:

- Generation revenues will be based on market prices for generation services, instead of through cost-of-service regulation.
- Customers increasingly will have access to flexible prices that reflect fluctuations in spot-market prices for generation.

These are characteristics of most models of a restructured electric power industry. The economic forces released by such changes could have significant impacts on 3 types of electric utility DSM: energy efficiency, load building, and real-time pricing and other flexible load-shape programs.

Energy Efficiency in a Competitive Electric Power Market

Energy-efficiency programs were designed in an IRP framework in which regulators required utilities to consider the benefits and costs of substituting such programs for the acquisition of new generation resources. In a deregulated competitive market, generating capacity will likely be added or retired based upon its marketability. Resource planning will become a competitive business function. This change is leading some commentators to question the continuing role of energy-efficiency programs. The resulting debate focuses on three issues:

- The ability of markets to capture cost-effective energy-efficiency opportunities.
- The costs of energy-efficiency programs in a competitive electric power market and the benefits of the programs to consumers and society.
- The rate impacts of energy-efficiency programs.

The Ability of Markets to Capture Cost-Effective Energy-Efficiency Opportunities

Technology-based evaluations suggest that many cost-effective energy-efficiency improvements are not rapidly adopted in the marketplace. For example, in 1990, the Electric Power Research Institute estimated that 20 percent of total U.S. electricity consumption could be saved with energy-efficiency measures costing less than 3.5 cents per kWh saved.[29] Others suggest much higher potential savings.[30] Given the measures considered in such studies, it appears that consumers acting on their own do not adopt many commercially available and cost-effective efficiency measures. This finding is consistent with a second group of studies of actual consumer purchasing practices indicating that residential consumers act as if they severely discount the value of future energy savings when making energy-efficiency investments.[31] A third group of studies examining commercial and industrial customer behavior found that such customers seldom undertake major energy-efficiency investments with more than a 2-year simple payback.[32] For many measures, a 2-year payback implies that energy-efficiency investments have to produce an after tax return on investment of 30 percent or higher.

Economists, technologists, and social science researchers are engaged in a debate concerning the source of this non-cost-effective consumer behavior.[33] Such behavior may be the result of barriers to the adoption of efficiency measures which represent real costs of efficiency improvements or failures of markets to operate efficiently. Energy-efficiency programs that remedy or offset genuine market failures could increase overall economic efficiency in comparison to competitive market outcomes. Three primary perspectives are being advanced in this debate.

First, some economists argue that there must be “hidden costs” associated with the adoption of efficiency measures.[34] In some cases, this argument is offered as a simple tautology: markets are presumed to operate efficiently; therefore, the failure of markets to adopt efficiency measures must be attributable to some cost not considered in conventional benefit/cost analysis. At this level, the hidden cost position adds little to the debate since the answer is assumed in the premise of the argument. There may be hidden costs such as minor inconveniences or differences in perform ance associated with the adoption of some efficiency measures. There may also be hidden benefits such as small improvements in performance or conveniences that are not considered in conventional benefit /cost studies. The hidden cost hypothesis is at best incom plete in that there are cases, such as efficient lighting ballasts, refrigerators, personal computers, and televisions, in which there is little or no possibility of hidden costs, yet cost-effective efficiency measures are not widely adopted.[35]

Second, some commentators relate the efficiency gap to uncertainty about future energy prices or other market conditions.[36] In the face of uncertainty, an efficient consumer may put off making deferrable investments. Most energy-efficiency improvements are made as part of a decision to invest in new equipment or a new building. If decisions to adopt efficiency measures are not made at the time a building is designed or equipment purchased, the opportunity is effectively lost. For example, it is not practical to change the orientation of a building to reduce summer heat gains after it is built. Nor can the consumer obtain a more efficient refrigerator without purchasing a new one. The opportunity to make energy-efficiency improvements exists when a building or appliance is acquired. Such efficiency investments are not deferrable. In these circumstances, efficient consumers must make decisions at the time of purchase based on the expected outcome of their choices regardless of the extent of uncertainty about market conditions.

A third view advanced by other economists, supported by social science researchers, and implicit in the positions of many technologists is that part of the efficiency gap may result from market failures related to the nature of the information involved in evaluating energy-efficiency investments. Economists identify two types of market failures in consumer evaluations of energy-efficiency investments:

- Information on the energy use of many products and services is not readily available or evident to many consumers when making energy efficient investments.[37] This also contributes to the difficulty of communicating the benefits of energy-efficient investments.[38] Energy use can be a low priority for some commercial and industrial establishments where energy costs represent approximately 3 percent of their total costs.
- Consumers may lack the expertise necessary to gather, process, and apply information to make optimal energy-efficient choices.[39] Additionally, recent experiments in economics show that consumers tend to repeat prior decisions when faced with unfamiliar choices and to avoid cost minimizing choices that have higher first costs.[40] In the market, such behavior impedes the commercialization of new energy-efficient technologies.

Such market failures may disproportionately impact the acceptance of new technology, limiting the ability of suppliers to achieve economies of scale, reduce product prices, and make energy-efficient technologies more competitive and widely available. They also may contribute to a more general market failure—new technology frequently has spillover benefits, making it difficult for the original developer to capture the full value of development and commercialization.

To the extent that market failures retard the commer cialization of energy-efficient technologies, utility or government energy-efficiency programs can play an essential role in pulling new technologies into the market place.

The Benefits and Costs of Energy Efficiency in a Competitive Generation Market

Short-term prices are significantly below the avoided costs of generating capacity assumed in DSM benefit/cost analysis just a few years ago. This could result in the discontinuance of DSM programs that are no longer cost-effective. This may account for part of the reduction in DSM activity. Increased competition is expected to improve the productivity and production efficiency of existing generation, delay retirement of some existing capacity, and lead to pricing that could flatten the difference between peak and off-peak loads. These effects can perpetuate surpluses and temporarily hold down market prices for generation. Given short-term capacity surpluses, the benefits of efficiency and other new resources could be more limited than assumed earlier in the decade. Even in the short-term, however, prices will not be uniformly low for all hours and locations. In the long run, restructuring might produce higher prices for generation services. In a restructured industry, the marketability of power can govern the addition of new capacity. New generating capacity will not be added until prices have risen sufficiently above the cost of new facilities to ensure generation suppliers a reasonable return at variable and uncertain market prices.[41] Additionally, utilities are discovering that targeting DSM to optimize or defer transmission and distribution capacity investments canproduce substantial benefits, not previously considered in DSM benefit/cost analysis.[42]

One of the benefits of energy efficiency is that reduced consumption avoids environmental impacts associated with electric generation. In the last few years, a series of studies were completed that attempt to place damage cost valuations on emissions from electric power plants. Some of these studies have tried to quantify externality values. However, they do not include estimates of environmental damage associated with global climate change.[43] If concerns about climate change and other environmental impacts of electric generation grow, this could lead to renewed interest in energy efficiency, one of the few low-cost approaches to reducing carbon dioxide emissions.

Overall, utility energy-efficiency programs are successful. In 1994, the mean utility cost for efficiency programs fell to 2.9 cents per kWh saved. A number of utilities were able to achieve substantial energy savings at costs below 2 cents per kWh saved[44] (Figure FE4). Some analysts question the costs of energy-efficiency rebate programs and the apparent disparity between high and low cost programs.[45] They point out that utility accounting, measurement, and reporting practices vary and that in some cases, customer costs are not included in reported program costs. More recent and detailed reviews of utility program evaluations adjust for inconsistent practices in response to these concerns.

In a detailed analysis of verified savings achieved, 20 utility commercial lighting programs were reviewed. All 20 programs were found to be cost-effective when compared to program-specific avoided costs.[46] A more comprehensive review of evaluations for 40 large commercial programs that accounted for one-third of 1992 utility DSM spending was recently completed for the Department of Energy. Most of these programs, which account for 88 percent of utility and consumer spending on programs included in the study, were cost-effective. For all the programs analyzed, the savings weighted average ratio of total resource benefits to total resource costs was 3.2 to 1.[47] Eight programs had total resource costs at or below 2« cents per kWh. There are examples of programs, particularly smaller programs, that are not cost-effective. Overall, however, utilities demonstrate a capability to undertake highly cost-effective large energy-efficiency programs.

These results are significant because: (1) they reflect only the direct effects of utility conservation programs and ignore secondary impacts on the availability of newtechnology and market behavior; and (2) large-scale utility energy-efficiency programs are relatively new and their performance continues to improve.

Some recent utility programs focused on creating a lasting transformation in regional or national energy markets by bringing new technologies into the market place or changing standard practices. For example, a national consortium of 24 utilities sponsored the “Golden Carrot” Super-Efficient Refrigerator Program that awarded $30 million in manufacturer incentives to the manufacturer introducing and marketing the most efficient new refrigerators. Whirlpool Corporation's winning bid resulted in the introduction, in 1994, of CFC-free refrigerators that used 29.4 percent less energy than the 1993 Federal Appliance Efficiency Standard. The objective of such programs is to introduce new technologies and practices that subsequently could retain and expand market share without the need for continuing financial incentives. Such programs can reduce utility costs per kWh saved. They also begin to address the equity questions that are raised because participants may benefit more than non-participants from rebate programs. By changing the products available in the market place, such programs produce benefits both for direct participants and other customers who may later take advantage of the availability of improved technology.

Rate Impacts of Energy-Efficiency Programs

Utilities and regulators cite the rate impacts of energy-efficiency programs as a reason for reducing savings targets or avoiding reliance on large rebates. These rate impacts reflect the net impact of revenue losses associated with reduced utility sales, direct and indirect program costs to the utility, and the supply cost savings associated with reduced demand and energy consumption. For many utilities, the largest contributing factor is the revenue loss that occurs under conventional rate design practices. In a regulated environment, conventional rate design practices lead to energy and demand charges substantially in excess of utilities’ short-run marginal costs. The difference between a utility's energy charges and marginal costs reflects a contribution to the recovery of the utility’s fixed costs. When conservation programs reduce sales, conventional rate designs result in a net revenue loss to the utility. Utilities must adjust rates to recover the net lost revenues by spreading the recovery of fixed costs over a reduced sales volume.

As utilities move into a competitive environment, their energy charges will inevitably fall towards marginal costs. This already is evident in the rates that many utilities are offering their largest customers and will be essential to the utilities' ability to compete for incremental sales. As the industry continues to move towards restructuring, rates are likely to be unbundled with the price of competitive services separated from other components of the customers' bills and pushed towards their marginal costs. Any remaining fixed costs could be recovered through a fixed access, customer, or demand charge. A series of studies documented that changing rate design practices could dramatically reduce negative rate impacts, in some cases even producing a reduction in average rates over the life of the efficiency measures.[48] These studies suggest that large rate impacts from efficiency programs are a short-term consideration and could be substantially mitigated through optional rate designs and cost allocation prac tices. As competition increases, more efficient rate design practices will greatly reduce the rate impacts that have been associated with efficiency programs.

Consumer and Utility Interests in Energy Efficiency Programs

In evaluating whether the projected reductions in 1995 energy-efficiency programs represent a transitional or a longer-term phenomenon, it is useful to consider how restructuring may affect consumer and utility interests in energy-efficiency programs.

In a competitive market, the effects of significant efficiency programs will be to reduce demand and to lower the market price of generation services. These benefits would accrue to all electricity consumers in relevant market areas. Given that generation revenues in a fully competitive market will be recovered at market prices, instead of on a cost-of-service basis, the interests of utilities in operating such programs will change. In the regulated environment, utilities have an obligation to serve, including the obligation to build or acquire generation resources. Energy-efficiency programs offer an attractive way to avoid the need for investment in new capacity. In a fully competitive environment, the obligation to serve could become an obligation to provide access to the transmission and distribution grid. In a competitive market for genera tion services, it is in the vertically integrated utility’s interest, as competitive generation supplier, to sell more generation services at a higher market price.[49] Efficiency programs will bring this interest into conflict with the utility’s traditional service objective of helping customers reduce their total energy bills. Energy-efficiency programs typically reduce energy consumption and may place downward pressure on the price of generation. This downward pressure on generation prices could reduce utility profits. This shift in the interests of local utilities might help to explain reductions in savings from DSM programs.

Policymakers who wish to retain a broader set of efficiency programs face two challenges. First, a means of financing such programs that does not penalize the local utility in comparison to other generation suppliers has to be identified. Several commentators suggest a system-benefits charge to be paid by all consumers seeking to access the transmission and distribution grid.[50] Such charges might take the form of fixed access fees, usage-based charges, or an “uplift” equal to a percentage of electricity costs. Some States have adopted analogous universal service charges to address public policy objectives in competitive telecom munications markets. Such charges would be non-bypassable and competitively neutral, paid by all consumers with access to the grid regardless of their choice of generation supplier.

Second, policymakers have to address reluctance on the part of local utilities to implement programs that reduce demand and potentially reduce market prices for their generation. Several options are being dis cussed including divestiture of local distribution utilities' interests in competitive generation, establish ment of conservation trusts, creation of separate conservation utilities, and/or an expanded competitive bidding process that allows product manufacturers, vendors, and others to compete for incentives to support technology commercialization and market transformation. These options avoid the situation in which only the incumbent generation supplier could offer efficiency programs paid for by all consumers.

Customer Service and Load Building Programs

Electric utilities' competitive interest in expanding sales does not mean that all energy efficiency and DSM opportunities will be ignored. When asked about the impacts of growing competition on DSM activities, several utilities indicated that they will increasingly focus on offering energy services to customers. Packaging generation with efficient electric devices, in some cases, may help utilities attract and retain customers. Some utilities are effective in using energy-efficiency programs as a way to attract or retain industrial customers.[51] Many utilities are utilizing DSM to compete with natural gas or to market electro-technologies. In 1994, the annual energy effects of load building programs were projected to double from 3,059 giga watthours (GWh) in 1995 to 6,251 GWh in 1999.[52]

Real-Time Pricing and Other Flexible Load- Shape Programs

Under current regulation, most customers are served under rates based on average embedded costs.[53] Customers receive a single, high level of service reliability. And, for most customers, the same rate applies throughout the year or large periods during the year, regardless of the actual cost to the utility of generating electricity in any given hour or of distributing electricity to any particular portion of the transmission and distribution grid. As a result, consumers have little opportunity to control their electricity costs by matching their preferences regarding the cost, timing, and reliability of service to the price and character of the services purchased. New communication technologies are making it practical to provide consumers variable price signals and a range of other demand-side services.

Time-of-use pricing, real-time pricing, and other flexible load-shape programs can take advantage of the substantial variation in generation prices by time and location that is expected in a competitive market. Utilities have started offering real-time pricing to their largest customers and residential pilot programs that involve automated energy management, two-way communication systems, and time-of-use prices. Spot-market prices will fluctuate based on load levels, the availability of major generating units, and transmission constraints. In some cases, generation prices could fluctuate from less than 2 cents to as much as 15 cents per kWh on a significant number of days per year. During capacity shortages, prices could increase to 50 cents per kWh or higher, reflecting the cost of building new generation to serve peak loads and the price signals that might be required to match demand to available supply.

In a restructured industry where consumers choose their generation suppliers, some utilities, generation suppliers, and intermediary supply coordinators could be expected to package energy and information services. The packaging of energy and telecommuni cations services makes it possible to expand the DSM and other services available to consumers, including:

- *Time-of-Use and Real-Time Pricing:*
- Communication linkages can be used to send out variable price signals or schedule time periods when low, moderate, or high price levels will be in effect. The technology used to receive and respond to such price signals will be automated energy management systems that implement predetermined consumer preferences regarding tradeoffs between cost and comfort or convenience.
- *Customer-Influenced Load Management:*
- Two-way communications permit utilities to determine the effects of load management at the premise and end-use levels. Utilities could offer load control services that include a customer override option, with billing dependent upon whether the option was exercised.
- *Energy Information Services:*
- Communication and information management systems can be used to provide customers with an array of energy information services, including:
    1. Continuously updated breakdowns of monthly energy use by major appliance or end use and variable pricing category.
    2. Comparisons of energy use by appliance or end use in the current and prior periods.
    3. Projections of the monthly electricity bill based on partial month data.
    4. Comparisons of energy use to typical neighborhood profiles.
    5. DSM recommendations, including estimates of energy cost impacts of potential efficiency imp
  rovements.

Benefits from automated meter reading, remote connect/disconnect services, electronic billing, automated bill payment, theft or tampering detection, distribution automation, and non-energy services also may contribute to the cost-effectiveness of energy-related two-way communication systems.

In some cases, energy information services may be provided as part of a broad band communication net work that also makes available cable TV, telephone, internet, security system, video-on-demand, medical alert, and other telecommunications services. But, a choice of communication technologies, including use of existing telephone lines, wireless, and hybrid fiber optic/coaxial cable systems, will permit energy information services to develop at a pace that is independent of the construction of broad band tele communication networks.

There is significant interest within the industry in packaging flexible pricing, load management, energy information, and other services. The extent to which such approaches become cost-effective for small consumers will depend upon the degree of variation in spot prices, the number of hours per year in which spot prices are high, the willingness of customers to pay for energy information and other services, and the ability of manufacturers to continue to lower the cost of communication and energy management systems.

Conclusion

In conclusion, it appears that in 1994 DSM programs were impacted by increasing competition in the electric power industry, while decreases in potential peak load reductions and in the growth of annual energy savings were projected for most DSM programs for 1995. A part of the reported reduction in the growth in the annual energy savings was caused by under-reporting of energy savings from past installations of energy-efficiency measures that continue to provide savings, but were installed under programs that are no longer in existence. EIA is addressing this problem in its 1995 survey. After correcting for major instances of under-reporting, the growth in annual energy savings projected for 1995 remained below that achieved in prior years.

Reduced growth in energy savings and peak load reductions may be a reflection of a number of factors: lower avoided costs; concerns regarding competition and rate impacts; and regulatory uncertainty during a transition toward a competitive environment. Another factor may be the conflict between integrated utilities' financial interests as suppliers of competitively priced generation and the potential of DSM programs to reduce load and market prices for generation. Electric utilities' long-term projections show a resumption of growth in annual energy savings and peak load reductions by 1999. Projected DSM spending levels suggest that utilities plan to retain a substantial portion of their capability to implement DSM programs.

As the industry considers major restructuring, the scope and character of electric utility DSM are likely to change. Market interventions designed to accelerate the commercialization of new energy-efficient technologies or practices may continue to be justified as a means of reducing market failures. However, the trends evident in the Form EIA-861 data raise questions as to whether new program and institutional options should be considered to address this objective. At the same time, restructuring could greatly expand other demand-side activities including the use of real time pricing, time-of-use pricing, automated energy management, energy information services, and other services designed to expand the ability of customers to respond to changing price signals. Providing service packages that include generation, management of the price risks associated with competitive generation markets, and demand-side services could help attract and retain customers in acompetitive market. The future of DSM will be determined by the choices that consumers, utilities, other service providers, regulators, and legislators make during the transition to competitive electric power markets.

END NOTES

[1] Paul Centolella's support and contribution to the Electric Operating and Financial Data Branch in preparing this article are greatly appreciated.

[2] The 1978 Public Utility Regulatory Policies Act, Public Law 95-617, 16 U.S.C. 2601 and 2621(d)(6).

[3] M. D. Levine, et al., Mitigation Options for Human Settlements, International Panel on Climate Change Working Group II, Chapter III-D (August 23, 1994); A. Rosenfeld, et al., "Conserved Energy Supply Curves for U.S. Buildings," Contemporary Policy Issues (January 1993), p. 45; Alliance to Save Energy, American Council for Energy Efficient Economy, Natural Resource Defense Council, and Union of Concerned Scientists, America's Energy Choices: Investing in a Strong Economy and a Clean Environment, Technical Appendices (Cambridge, MA, 1991); National Academy of Sciences, Policy Implications of Greenhouse Warming: Report of the Mitigation Panel (Washington, DC: National Academy Press 1991); Office of Technology Assessment, U.S. Congress, Changing by Degrees: Steps to Reduce Greenhouse Gases, OTA-O-482 (Washington, DC, 1991); Barakat and Chamberlin, Inc., Efficient Electricity Use: Estimates of Maximum Energy Savings, EPRI, CU-6747 (1990); R. Carlsmith, et al, Energy Efficiency: How Far Can We Go? (Oak Ridge, TN: Oak Ridge National Laboratory, 1990); U.S. Dept. of Energy, Office of Conservation, Energy Conservation Multi-Year Plan 1990-1994 (August 1988); H. Geller, et al, Pacific Gas & Electric Residential Conservation Power Plant Study (February 1986); A. Meier, et al, Supplying Energy Through Greater Efficiency: The Potential for Conservation in California's Residential Sector (1983); Solar Energy Research Institute, A New Prosperity -- Building a Sustainable Energy Future (Andover, MA: Brick House Publishing, 1981); The National Research Council, Alternative Energy Demand Futures to 2010 (1979).

[4] Marginal Cost is the cost of producing a small additional increment of power. Short-run marginal costs reflect the cost of delivering that increment of power from existing generating capacity.

[5] The 1990 Clean Air Act Amendments, 42 U.S.C. §7651c, and the Energy Policy Act of 1992, 16 U.S.C. §2621(d)(8), contain specific provisions designed to encourage States to adopt ratemaking mechanisms that remove the disincentives to effective implementation of energy-efficiency programs. EPACT also requires State utility commissions to consider standards that will require utilities to employ integrated resource planning .

[6] Energy Information Administration, "Evaluation and Verification of Demand-Side Management Programs," U.S. Electric Utility Demand-Side Management 1993, DOE/EIA-0589(93) (Washington, DC, July 1995).

[7] Large utilities are those with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours per year.

[8] Electric utilities report estimates of savings and peak load reductions. These reports are subject to a quality assurance review performed by EIA. The reports for major utilities are compared to utility filings

with the utilities' State regulators. Utilities are contacted for clarifications when reporting issues are identified. Utilities were asked to indicate whether energy savings or peak load reductions are subject to verification. For prior years, estimated savings have subsequently been compared to program evaluation results. While estimated savings in some cases exceeded subsequently verified results, a large variance between estimated and verified savings was not found (U.S. Electric Utility Demand-Side Management, 1993, "Estimation and Verification of Demand-Side Management Programs"). Utilities report actual peak load reductions for energy-efficiency programs and both potential peak load reductions and actual peak load reductions for direct load control, interruptible load, other load management, and other DSM programs. Potential peak reductions reflect the installed load reduction capability of the utility. Actual effects reflect the load reductions achieved from programs in place at the time the utility experiences its annual peak load. For purposes of this paper, the sum of actual peak load reductions from energy-efficiency programs and potential peak load reductions from direct load control, interruptible load, other load management, and other DSM programs will be referred to as potential peak load reductions. Incremental energy savings are reported on an annualized basis, as if savings had been achieved for a full calendar year regardless of the date during the year on which individual measures were installed.

[9] From the turn of the century until about 1970, electric utilities were able to reduce generation costs by building larger generating units -- some as large as 1,300 megawatts. Thereafter, further increases in maximum unit size failed to provide economic advantages given technical, construction lead time, and reliability constraints. (R. Hirsh, Technology and Transformation in the American Electric Utility Industry (Cambridge, U.K.: Cambridge University Press 1989).) Today the optimum size for new generating capacity may be 150 megawatts or less. (C. Bayless, "Less is More: Why Gas Turbines Will Transform Electric Utilities," Public Utilities Fortnightly, (December 1, 1994) p.21.)

[10] National Association of Regulatory Utility Commissioners, Utility Regulatory Policy in the United States and Canada: Compilation 1992-1993 (Washington, DC, 1993), p. 421.

[11] In Re TECO Power Services and Tampa Electric Company, 52 FERC ¶61,191 (1990); In Re Ocean State Power II, 59 FERC ¶61,360 at 62,323-4 (1992).

[12] Energy Policy Act of 1992, Pub. L. No. 102-486, Stat. 2776 (1992).

[13] Energy Information Administration Form EIA-867, "Annual Nonutility Power Producer Report."

[14] Energy Information Administration, Electric Power Annual 1992, DOE/EIA-0348(92) (Washington, DC, January 1994), p. 12.

[15] Federal Energy Regulatory Commission (FERC) Form 1 "Annual Report of Major Electric Utilities, Licensees and Others" (1994) and McGraw-Hill, Power Markets Week. (1994).

[16] Spot-market prices during peak and mid-peak periods are low because they reflect the current

surpluses of generating capacity in many parts of the country. The generation costs built into utility rates are higher because they are based on the utility's embedded or historical costs and reflect surplus capacity, high cost plants completed in the 1980's and early 1990's, and other fixed or already incurred costs.

[17] Federal Energy Regulatory Commission, Promoting Wholesale Competition through Open Access Non-Discrimination Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket Nos. RM95-8-000 and RM94-7- 001, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking (March 29, 1995).

[18] Federal Energy Regulatory Commission, Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, 69 FERC ¶61,086 (1994).

[19] Federal Energy Regulatory Commission, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Public Proposed Rulemaking, 59 Federal Register 35274 (July 11, 1994).

[20] Federal Energy Regulatory Commission, New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC-714, FERC Docket No. RM 93-10-000, Final Rule (September 30, 1993).

[21] E. Kahn & S. Stoft, Organization of Bulk Power Markets (Berkeley, CA: Lawrence Berkeley Laboratory 1996).

[22] C. Winston, "Economic Deregulation: Days of Reckoning for Microeconomists," Journal of Economic Literature, 31 (9) (September 1993) pp. 1,263-1,289.

[23] Legislative Energy Advisory Program, Quarterly Legislative Letter (December 1, 1995).

[24] For purposes of this article, actual peak load reductions from energy-efficiency programs are included in potential peak load reductions.

[25] This calculation of the cost of conserved energy is based upon 1994 reported incremental savings from efficiency programs, direct costs of efficiency programs, the allocation of indirect costs in proportion to direct costs by DSM program type, a conservative assumption of a 10-year average life, and discounting the value of future savings at a 5-percent real discount rate. Cost of conserved energy was calculated as follows:

$$CCE = \frac{PV(IC)}{\sum_{i=1}^{n} \left(\frac{S_i}{(1 + d)^{n-1}} \right)}$$

Where CCE = cost of conserved energy; PV(IC) = The present value of incremental program cost, for purposes of this calculation average 1994 program costs were assumed to approximate PV(IC) to the utility for programs installed in that year. (assumes all dollars are spent in initial year of program and no future maintenance costs); S = Net energy savings resulting from the program expressed as kWh saved in year "i", for purposes of this calculation 1994 incremental energy savings were assumed to approximate S for programs installed during the year; n = the number of years in which installed programs are expected to contribute to net energy savings, which may equal the useful life of the programs installed, for purposes of this calculation a 10-year average life was assumed; and d = the discount rate.

[26] In the Matter of the Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation, Docket No. R. 94-04-031 (April 20, 1994).

[27] M. Schweitzer and M. Pye, Key Factors Responsible for Changes in Electric-Utility DSM Usage (Oak Ridge, TN: Oak Ridge National Laboratory, Sept. 1995).

[28] M. Schweitzer and M. Pye, Key Factors Responsible for Changes in Electric-Utility DSM Usage (Oak Ridge, TN: Oak Ridge National Laboratory, Sept. 1995).

[29] A. Fickett, C. Gellings, & A. Lovins, "Efficient Use of Electricity," Scientific American (1990).

[30] See Endnote 3.

[31] Berkovec, J. et al., Heating System and Appliance Choice, Working Paper, MIT Energy Laboratory, Report #MIT-EL 83-004WP (January 1983); Cole, H. and R. Fuller, Residential Energy Decision Making: An Overview with Emphasis on Individual Discount Rates and Responsiveness to Household Income and Prices, Hillman Assoc., U.S. Department of Energy (February, 1981); Corum, K. and D. O’Neal, Investment in Energy-Efficiency Houses: An Estimate of Discount Rates Implicit in New Home Construction Practices, Energy, Volume 7, No. 4 (1982), pp. 389-400; Dubin, J., Econometrics Theory and Estimation of the Demand for Consumer Durable Goods and Their Utilization: Appliance Choice and the Demand for Electricity, MIT Energy Laboratory Discussion Paper No. 23, MIT-EP 82-035WP (May 1982); Gately, D., Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables: Comment, Bell Journal of Economics, Volume 11, No. 1 (Spring 1980), pp. 373-374; Goett,

A. and Moss, W., Implicit Discount Rates in Residential Customer Choices, Investments in Conservation Measures, EM-5587, Research Project 2574-1, Electric Power Research Institute, Palo Alto, CA (February 1988); Hausman, J., Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables, Bell Journal of Economics, Volume 10, No. 1 (Spring 1979), pp. 33-54; McRae, D., Rational Models for Consumer Energy Conservation, Burby and Marsden (eds.), Energy and Housing, Cambridge: Oelgeschleger, Gunn, and Hain, Publishers, Inc. (1980); Meier, A. and J. Whittier, Consumer Discount Rates Implied by Purchases of Energy-Efficient Refrigerators, Energy, Volume 8, No. 12 (1983), pp. 957-962; Ruderman, H., et al., The Behavior of the Market for Energy Efficiency in Residential Appliances Including Heating and Cooling Equipment, LBL-15304, Energy Analysis Program, Lawrence Berkeley National Laboratory (September 1984).

[32] W. Fuller, "Industrial DSM D What Works and What Doesn't," Proceedings on the 1992 ACEEE Summer Study on Energy Efficiency in Buildings, at 5.75 (August 1992); G. Hatsopoulos, et al., "Capital Investment to Save Energy," Harvard Business Review 111 (March-April 1978); A. Evans and S. Zussman, Barriers to the Adoption of Energy-Conserving Technologies in the Textile Industry, U.S. Department of Energy (1979); H. Landsberg, ed., Selected Studies on Energy: Background Papers for Energy: The Next Twenty Years, Ballinger Publishing Company, Cambridge, MA (1980); R. Stobaugh and D. Yergin, eds., Energy Future: Report of the Energy Project at the Harvard Business School, Ballantine Books, New York, NY (1979); Alliance to Save Energy, Industrial Investments in Energy Efficiency: Opportunities, Management Practices, and Tax Incentives: Summary, Washington, D.C.; H. Herzog, et al., Energy Management in Central Maine Power Company's Industrial Sector with Specific Emphasis in the Pulp and Paper Industry, Final Report for the Central Maine Power Company, Massachusetts Institute of Technology, MIT-EL 92-001 (March 1992); Niagara Mohawk Power Corporation, Niagara Mohawk Demand-Side Management (DSM) Subscription Option Status Report (April 12, 1994).

[33] E. Hirst and J. Eto, Justification for Electric-Utility Energy-Efficiency Programs, Oak Ridge National Laboratory (August 1995).

[34] L. Ruff, "Least-Cost Planning and Demand-Side Management: Six Common Fallacies and One Simple Truth," Public Utilities Fortnightly (April 28, 1988) p. 19; R. Sutherland, "Market Barriers to Energy-Efficiency Investment," The Energy Journal Vol. 12, No. 3 (1991) p. 15.

[35] M. Levine, et al., Energy Efficiency, Market Failures, and Government Policy, LBL-35376, ORNL/CON-383 (Berkeley, CA: Lawrence Berkeley Laboratory, March 1994).

[36] K. Hassett and G. Metcalf, "Energy Conservation Investment, Do Consumers Discount the Future Correctly?," Energy Policy (June 1993) p. 710.

[37] A. Sanstad and R. Hawarth, "'Normal' Markets, Market Imperfections and Energy Efficiency," Energy Policy, Vol. 22, No. 10 (1994) pp. 812-818; W. Kempton and L. Layne, "Consumer's Energy Analysis Environment," Energy Policy, Vol. 22, No. 1 (1994) p. 857; P. Komor, et al., Energy Use,

Information, and Behavior in Small Commercial Buildings, PU/CEES-240 (Princeton, NY: Princeton University, July 1989).

[38] S. DeCanio, "Barriers within Firms to Energy-Efficient Investments," Energy Policy, (September 1993) pp. 906-914.

[39] Sanstad and Hawarth, "'Normal' Markets, Market Imperfections and Energy Efficiency."

[40] H. Huntington, "Been Top Down So Long, It Looks Like Bottom Up to Me," Energy Policy October (1994) p. 833; R. Thaler, The Winner's Curse: Paradoxes and Anomalies of Economic Life (New York, NY: the Free Press (MacMillan), 1992); R. Thaler, "Toward a Positive Theory of Consumer Choice," Journal of Economic Behavior in Organization (March 1990) p. 39.

[41] A. Dixit and R. Pindyck, Investment Under Uncertainty (Princeton, NJ: Princeton University Press 1994); T. Kaslow and R. Pindyck, "Valuing Flexibility In Utility Planning,: The Electricity Journal, Vol 7, No. 2 (March 1994) p. 60; P. Centolella, "Prices, Options, and Investment in Competitive Power Markets," Proceedings of the Third National Energy Summit (1995).

[42] R. Orans, C. Woo, and J. Swisher, Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District (Palo Alto, CA: Electric Power Research Institute 1992); R. Pratt, et al., "Potential for Feeder Equipment Upgrade Deferrals in a Distributed Utility," Proceedings of the 1994 ACEEE Summer Study on Energy Efficiency in Buildings (August 1994) p. 2.229; S. Sparks, et al., "Producing More with Less: Evaluating the Impact of a T&D Agricultural DSM Program," Proceedings of the 1994 ACEEE Summer Study on Energy Efficiency in Buildings (August 1994) p. 2.49; R. Weijo and L. Ecker, "Acquiring T&D Benefits from DSM: A Utility Case Study," Proceedings of the 1994 ACEEE Summer Study on Energy Efficiency in Buildings (August 1994) p. 2.269.

[43] Energy Information Administration, Electric Generation and Environmental Externalities: Case Studies, DOE/EIA-0598 (Washington, DC, September 1995); Oak Ridge National Laboratory and Resources for the Future, Estimating Externalities of Coal Fuel Cycles, U.S. Department of Energy and The Commission of European Communities (September 1994); RCG Hagler-Bailley, New York Externalities Cost Study (1995); see also: California Energy Commission, Electricity Report, Appendix F (November 1992).

[44] Energy Information Administration, Form EIA-861, "Annual Electric Utility Report." This calculation of the cost of conserved energy is based upon 1994 reported incremental savings from efficiency programs, direct costs of efficiency programs, the allocation of indirect costs in proportion to direct costs by DSM program type, a conservative assumption of a 10-year average measure life, and discounting the value of future savings at a 5-percent real discount rate.

[45] P. Joskow and D. Marron, "What Does a Negawatt Really Cost? Evidence from Utility Conservation

Programs," The Energy Journal April (1992), pp. 41-74.

[46] J. Eto, et al., The Cost and Performance of Utility Commercial Lighting Programs, LBL-34967, UC-350 Lawrence Berkeley Laboratories (Berkeley, CA, May 1994).

[47] J. Eto et al., Where Did the Money Go? The Cost and Performance of the Largest Commercial Sector DSM Programs. (Berkeley, CA: Lawrence Berkeley National Laboratory, December ,1995).

[48] P. Centolella, Direct Testimony, In the Matter of Georgia Power Company's Application for Approval of an Integrated Resource Plan (1995); Niagara Mohawk Power Corporation, 1993 Update to the 1991 IERP (June 1993); E. Hirst and S. Hadley, Price Impacts of Electric-Utility DSM Programs, ORNL/CON-402 (November 1994) pp. 16-17.

[49] Utilities that do not own generation may avoid this conflict in objectives.

[50] See for example: P. Centolella, Testimony, In the Matter of the Obligation of the Association of Business Advocating Tariff Equity for Approval of an Experimental Retail Wheeling Tariff for Consumers Power Company, Case No. U-10143R, Michigan Public Service Commission (1994); R. Cavanagh, Usage Based System Benefit Charges: The New Regulatory Imperative for Avoiding Stranded Benefits (February 1995).

[51] J. Jordan and S. Nadel, Industrial Demand-Side Management Programs: What's Happened, What Works, What's Needed, U.S. Department of Energy and the Energy Foundation (March 1993); M. Kellogg, Staying Power Program Impact Evaluation, Bonneville Power Administration (August 1991); and Testimony of S. Larson, In the Matter of the Naragansett Electric Company, Rhode Island Public Utilities Commission, Docket No. 1939 (1992).

[52] It is possible that reductions in forecasted savings from efficiency programs could reflect some utilities reporting under the category of energy efficiency the net load impacts of programs designed to both attract load and improve the efficiency of customers currently using electricity. EIA has added instructions to the 1995 Form EIA-861 that address this issue.

[53] "Embedded costs" are the sum of current operating expenses, depreciation and amortization expenses associated with historical investments, and a reasonable return on the undepreciated and unamortized capital account balances associated with historical investments.

File last modified: April 10, 1997

Contact:

Channele Donald

mailto:cdonald@eia.doe.gov.
Phone: (202) 426-1270

URL: http://www.eia.doe.gov/cneaf/pubs_html/feat_dsm/contents.html

If you are having technical problems with this site, please contact the EIA Webmaster at wmaster@eia.doe.gov

Attachment 20.1

REFER TO ATTACHED SPREADSHEET

Attachment 25.1

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation and rulemaking to adopt, amend, or repeal regulations pertaining to Chapters 703 and 704 of the Nevada Administrative Code regarding energy efficiency programs as part of the integrated resource planning process and other related utility matters in accordance with Senate Bill 437 and demand side management cost recovery mechanisms and incentives.	Docket No. 07-06029

At a general session of the Public Utilities Commission of Nevada, held at its offices on March 13, 2008.

PRESENT: Chairman Jo Ann P. Kelly
Commissioner Rebecca D. Wagner
Commissioner Sam A. Thompson
Commission Assistant Secretary Donna Skau

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

1. On June 6, 2007, the Commission voted to open an investigation and rulemaking to adopt, amend, or repeal regulations pertaining to Chapters 703 and 704 of the Nevada Administrative Code ("NAC") regarding energy efficiency programs as part of the integrated resource planning process and other related utility matters in accordance with Senate Bill 437. This matter has been designated by the Commission as Docket No. 07-06029.

2. On September 26, 2007, the Commission voted to expand the scope of Docket No. 07-06029 to include demand side management cost recovery mechanisms and incentives investigated in Docket No. 06-12005.

3. This matter is being conducted by the Commission pursuant to the Nevada Revised Statutes ("NRS") and the NAC Chapters 233B, 703, and 704, including but not limited to, NRS 704.210.

4. On October 12, 2007, the Commission issued a Notice of Investigation and Rulemaking, Request for Comments, and Notice of Workshop in Docket No. 07-06029 in accordance with state law and the Commission's rules of practice and procedure.

5. On October 12, 2007, the Presiding Officer issued a Procedural Order directing the Regulatory Operations Staff ("Staff") of the Commission to conduct a small business impact assessment in accordance with NRS 233B.0608(1).

6. On November 1, 2007, EnerNOC, Inc. ("EnerNOC") filed its Notice of Intent to Participate as a Commenter in Docket No. 07-06029.

7. On November 1, 2007, Nevada Power Company ("NPC") and Sierra Pacific Power Company ("SPPC"), EnerNOC, International Energy Conservation ("IEC"), Southwest Energy Efficiency Project ("SWEEP"), and the Attorney General's Bureau of Consumer Protection ("BCP") each filed written comments.

8. On November 2, 2007, Comverge, Inc. ("Comverge") filed its Notice of Intent to Participate as a Commenter in Docket No. 07-06029.

9. On November 6, 2007, the Commission issued a Revised Notice of Workshop, revising the workshop date from November 15, 2007 to December 5, 2007.

10. On November 8, 2007, NPC and SPPC, and Staff filed written reply comments.

11. On November 19, 2007, the Commission issued an Order that found that the proposed regulation in Docket No. 07-06029 does not impose a direct or significant economic

burden upon small businesses, nor does it directly restrict the formation, operation, or expansion of a small business.

12. On November 19, 2007, the Presiding Officer issued a Notice of Intent to Act Upon a Regulation, and Notice of Hearing for the Adoption, Amendment, or Repeal of Regulations of the Public Utilities Commission of Nevada in Docket No. 07-06029.

13. On December 5, 2007, the Commission held a duly noticed workshop in Docket No. 07-06029. Appearances were made at the workshop by NPC and SPPC, Comverge, EnerNOC, IEC, SWEEP, BCP, and Staff. The participants discussed their filed comments regarding suggested changes to the regulations in this Docket.

14. On December 12, 2007, NPC and SPPC, and Staff filed written comments.

15. On December 13, 2007, EnerNOC filed written comments.

16. On December 13, 2007, ConsumerPowerline filed a Petition for Leave to Intervene and Initial Comments with its Request to Present Issues at a Public Hearing in Docket No. 07-06029.

17. On December 14, 2007, IECC filed written comments.

18. On December 20, 2007, the Commission held a duly noticed hearing in Docket No. 07-06029. Appearances were made at the hearing by SPPC and NPC, ConsumerPowerline, IEC, SWEEP, BCP, and Staff.

19. During the hearing the discussion of the participants reflected that separate treatment of the dispatchable direct load control programs for the purpose of recovering incentives paid to customers was an acceptable compromise that would not effect a disincentive to the utilities.

20. On January 9, 2008, the Commission adopted the proposed regulations as permanent regulations.

21. Subsequently, the Legislative Counsel Bureau requested that the Commission provide a definition for the term "Total Resource Cost test."

22. On February 27, 2008, the Commission held a second duly noticed hearing in Docket No. 07-06029. Appearances were made at the hearing by SPPC and NPC, IEC, SWEEP, BCP, and Staff.

23. Proposed language defining Total Resource Cost test was distributed to the participants during the hearing. The Commission provided one version and Staff provided a second version. All of the participants accepted the version provided by the Commission.

24. The Commission finds that it is in the public interest to adopt the proposed regulations, attached hereto and incorporated herein as Attachment 1, as permanent regulations.

//

//

//

//

//

//

//

//

//

THEREFORE, based upon the foregoing findings of fact and conclusions of law, it is hereby ORDERED that:

1. The proposed regulations, attached hereto as Attachment 1 are ADOPTED as permanent regulations pursuant to NRS 233B.040 and 233B.060.

2. The Commission retains jurisdiction for the purpose of correcting any errors which may have occurred in the drafting or issuance of this Order.

By the Commission,

JO ANN P. KELLY, Chairman and
Presiding Officer

REBECCA D. WAGNER, Commissioner

SAM A. THOMPSON, Commissioner

Attest:
CRYSTAL JACKSON, Commission Secretary

Dated: Carson City, Nevada
3/18/08
(SEAL)

PUBLIC UTILITIES COMMISSION
PUC
OF NEVADA

ATTACHMENT 1

PROPOSED REGULATION

OF THE

PUBLIC UTILITIES COMMISSION OF NEVADA

Docket No. 07-06029/LCB File No. R162-07

February 27, 2008

Explanation- Matter in *italics* is new; matter in ~~strikethrough~~ is material to be omitted.

AUTHORITY: §1, NRS 703.025, 704.210 and 704.741; §2, NRS 703.025, 704.210 and 704.751.

A REGULATION relating to public utilities; requiring electric utilities to include an energy efficiency program in a demand side plan to promote conservation and demand management; providing accounting requirements for dispatchable direct load control programs; and providing other matters properly relating thereto.

Section 1. NAC 704.934 is hereby amended to read as follows:

704.934 1. As part of its resource plan, a utility shall submit a demand side plan.

2. The demand side plan must include:

(a) An identification of end-uses for programs for conservation and demand management.

(b) An assessment of savings attributable to technically feasible programs for conservation and demand management, as determined by the utility. The programs must be ranked in a list according to the level of savings in energy or reduction in demand, or both.

(c) An assessment of technically feasible programs to determine which will produce benefits in peak demand or energy consumption. The utility shall estimate the cost of each such program. The methods used for the assessment must be stated in detail, specifically listing the data and assumptions considered in the assessment.

3. In creating its demand side plan, a utility shall consider the impact of applicable new technologies on current and future demand side options. The consideration of new technologies

must include, without limitation, consideration of the potential impact of advances in digital technology and computer information systems.

4. *In its demand side plan for residential customers, a utility shall include an energy efficiency program that reduces the consumption of electricity or any fossil fuel. The energy efficiency program must include, without limitation, the use of new solar thermal energy sources. For purposes of this section, "new solar thermal energy sources" refers to those sources installed after the energy efficiency program's effective date that displace electricity or any fossil fuel consumption by using solar radiation to heat water or provide space heating or cooling*

[~~4.~~] *5.* The demand side plan must provide a list of the programs for which the utility is requesting the approval of the Commission. The list must include *without limitation*:

(a) An estimate of the reduction in the peak demand and energy consumption that would result from each proposed program, in kilowatt-hours and kilowatts saved. The programs must be listed according to their expected savings and their contribution to a reduction in peak demand and energy consumption based upon realistic estimates of the penetration of the market and the average life of the programs.

(b) An assessment of the costs of each proposed program and the savings produced by the program. If the program can be relied upon to reduce peak demand on a firm basis, the assessment must include the savings in the costs of transmission and distribution.

(c) An assessment of the impact on the utility's load shapes of each proposed and existing program for conservation and demand management.

(d) If a program is an educational program, the projected expenses of the utility for the educational program.

[~~5.~~] *(e) For any conservation or demand management program which reduces the consumption of electricity or any fossil fuel, the utility must include in its demand side plan a complete life-cycle cost analysis of the costs and benefits of the program in the form of the Total Resource Cost test.*

(f) As used in this section, the Total Resource Cost test is a measure of the overall economic efficiency of a DSM program from the perspective of society which measures the net costs of a DSM program based on the total costs of the program, including both participant and utility costs.

6 The utility shall include with its demand side plan a report on the status of all programs for conservation and demand management that have been approved by the Commission. The report must include tables for each such program showing, for each year, the planned and achieved reduction in kilowatt-hours, the reduction in kilowatts and the cost of the program.

[~~6.~~] *7.* On or before August 15 of each year following the filing of its resource plan, the utility shall file with the Commission a copy of the complete analysis the utility used in determining for the upcoming year which conservation and demand management programs are to be continued and which programs are to be cancelled. The Commission will process this analysis in the same manner as an amendment filed pursuant to NAC 704.9503.

Section 2. NAC 704.9523 is hereby amended to read as follows:

704.9523 1. All costs of implementing programs for conservation and demand management must be accounted for in the books and records of a utility separately from amounts attributable to any other activity. All accounts must be maintained in a manner that will allow costs attributable to specific programs to be readily identified.

2. A utility may, pursuant to subsection 3, *and with the exception stated in subsection 4,* recover all prudent and reasonable costs incurred in implementing programs for conservation and demand management *programs* that have been approved by the Commission as part of the action plan of the utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing and evaluation. The utility may recover approved costs associated with monitoring and evaluating *these* programs ~~[for conservation and demand management]~~ through a general rate case.

3. To recover costs incurred in implementing programs for conservation and demand management, a utility must:

(a) Calculate, on a monthly basis, the costs incurred in implementing each program since the end of the test period or period of certification in its last proceeding to change general rates.

(b) Record the cost of implementing each program, as calculated pursuant to paragraph (a), in a separate subaccount of Account 182.3 (Other Regulatory Assets) for each program and make an appropriate offset to other subaccounts.

(c) Maintain subsidiary records of the subaccounts of Account 182.3 for each program. These records must clearly delineate all costs incurred by the utility in implementing each program approved by the Commission.

(d) Apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the balance in the subaccounts of Account 182.3 for each program not included in the rate base.

(e) Clear any balance accumulated in the subaccounts of Account 182.3 for each program as a component of an application by the utility to change general rates as follows:

(1) The Commission will adjust the rate to amortize the balance over a *three-year* period, *unless otherwise specified by the Commission* ~~[determined by the Commission to be appropriate for clearing the account and consistent with the life of the investment]~~.

(2) The utility must begin amortizing costs on the date that the change in general rates becomes effective.

(3) The utility must include the balance in the subaccounts of Account 182.3 for each program, including carrying charges, in the rate base as of the date that ends the test period used in the utility's application to change general rates or as of the date that ends the period of certification, whichever is later.

(4) To calculate revenue requirements, the utility must base the rate of return to be applied to the balance in the subaccounts of Account 182.3 for each *conservation or demand management* program that the utility has carried out on the authorized return on equity plus 5 percent.

4. The costs incurred in implementing dispatchable direct load control programs shall be recovered pursuant to subsection 3, except for the costs of incentives paid to customers which will be treated as fuel and purchased power expense pursuant to NAC sections 704.095 through 704.195.

5. As used in this section, "dispatchable direct load control program" means a program offered by a utility pursuant to which customers may agree to allow the utility to remotely interrupt or cycle electrical equipment and appliances, including, without limitation, air conditioners, water heaters and space heaters

Attachment 25.2

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

BRITISH COLUMBIA UTILITIES COMMISSION

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

Log No. 12605

VIA E-MAIL
david.bennett@fortisbc.com
lavern.humphrey@fortisbc.com

May 23, 2006

Mr. David Bennett
General Counsel and Corporate Secretary
FortisBC Inc.
5th Floor
1628 Dixon Avenue
Kelowna, B.C. V1Y 9X1

Dear Mr. Bennett:

Re: FortisBC Inc. ("FortisBC")
Project No. 3689410/Order No. G-130-05
2006 Revenue Requirements Application ("Application")

Further to your November 24, 2005 application for approval of FortisBC's 2006 Revenue Requirements, we enclose Commission Order No. G-58-06 and attached Appendix 1 Settlement Agreement.

Yours truly,

Original signed by:

Robert J. Pellatt

RJP/cms
Enclosure(s)
cc: Registered Intervenors & Interested Parties

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-58-06

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

An Application by FortisBC Inc.
for Approval of its F2006 Revenue Requirement Application and
Establishment of a Multi-Year Performance Based Regulation Mechanism

BEFORE: L.F. Kelsey, Panel Chair
and Commissioner
L.A. O'Hara, Commissioner

May 19, 2006

O R D E R

WHEREAS:

A. On November 24, 2005, FortisBC Inc. ("FortisBC") filed for approval of its 2006 Revenue Requirements and to establish a Multi-Year Performance Based Regulation Mechanism (the "Application") with the British Columbia Utilities Commission ("Commission") pursuant to Sections 60 and 61 of the Utilities Commission Act (the "Act"); and

B. The Application requested an interim rate increase of 5.9 percent, effective January 1, 2006. The increase is based, in part, on significant capital expenditures, a change in the amortization rates for various assets and an increase in the amount of overheads charged to capital; and

C. The Application also proposed a Performance Based Regulation ("PBR") mechanism to determine Revenue Requirements for the years 2007 to 2009; and

D. Commission Order No. G-52-05 dated May 31, 2005 approving FortisBC's 2005 Revenue Requirements Application, directed an Annual Review of the 2005 incentive sharing mechanism along with a Review of the Performance Based Regulation Mechanism; and

E. The Commission issued Order No. G-130-05 dated December 2, 2005 approving for FortisBC an interim rate increase of 5.9 percent effective January 1, 2006, and established a regulatory timetable for an Annual Review and Workshop on Thursday, February 9, 2006 and a Pre-hearing Conference on Friday, February 10, 2006; and

F. At the 2005 Annual Review held on February 9, 2006 in Kelowna, BC, FortisBC presented actual 2005 incentive adjustments for both shared and flow-through components along with Performance Standards on System Reliability, Customer Service and Informational Metrics; and

G. The Intervenors had no comments with respect to the 2005 Incentive Sharing by the due date of February 16, 2006. The Commission issued Order No. G-21-06 on March 9, 2006 approving the Incentive Adjustments; and

H. On February 14, 2005, FortisBC filed its Evidentiary Update with a net reduction in the rate increase from 5.9 percent to 4.6 percent. The rate increase was further revised to 5.8 percent on April 11, 2006 pursuant to Commission Order No. G-14-06 amending the Automatic Adjustment Mechanism for setting Return on Equity ("ROE") which increased FortisBC's allowed ROE from 8.69 percent to 9.20 percent effective January 1, 2006; and

I. By Order No. G-13-06, the Commission established a regulatory timetable for a Negotiated Settlement Process for reviewing the Application starting April 18, 2006. If a Negotiated Settlement was not reached, an Oral Public Hearing would commence on June 20, 2006; and

J. The Negotiated Settlement discussions regarding the Application were held on April 18 and 19, 2006, and a proposed Settlement Agreement with a net rate increase of 5.9 percent was agreed to by FortisBC and most of the Intervenors with assistance from Commission Staff; and

K. The Participants at the Negotiated Settlement provided Letters of Support by May 8, 2006 for the Settlement Agreement with the exception of one Participant and by the due date of May 15, 2006 no comments were received from Registered Intervenors who had not participated in the Settlement process; and

L. The Commission has reviewed the proposed Settlement Agreement and considers that approval is warranted.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for FortisBC the Settlement Agreement for its 2006 Revenue Requirements and the Multi-Year Performance Based Regulation Plan for 2007 to 2009 attached as Appendix 1 to this Order, the Terms of Settlement.

2. The interim rates for FortisBC established by Order No. G-130-05 are approved as permanent rates effective January 1, 2006.

3. The Commission will accept, subject to timely filing, amended Electric Tariff Rate Schedules in accordance with this Order.

…/3

4. FortisBC is to inform all affected customers of the final rates by way of a customer notice.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of May 2006.

BY ORDER

Original signed by:

Len Kelsey
Panel Chair and Commissioner

Attachment

TERMS OF SETTLEMENT

2006 Revenue Requirements and
Multi-Year Performance Based Regulation Plan for 2007 – 2009
FortisBC Inc.

Negotiated Settlement

FortisBC Inc. ("FortisBC" or the "Company") filed an Application on November 24, 2005 for its 2006 Revenue Requirements, and for a multi-year Performance Based Regulation ("PBR") Plan for the period 2007 to 2009. The Company's 2005 rates had been set (Order G-52-05) following an oral public hearing which examined in detail not only FortisBC's cost of service, capital structure and Return on Equity premium, but its long-term System Development Plan and its Resource Plan. The Application proposed a two-stage Negotiated Settlement Process ("NSP") to set 2006 rates, followed by a second stage to determine the parameters of a PBR mechanism for a further three year period.

By Order G-130-05, the Commission approved FortisBC's request for an interim, refundable rate increase of 5.9 percent effective January 1, 2006. The Order also established a Regulatory Timetable for the Company's 2005 Annual Review and a workshop to review the 2006 Revenue Requirements on February 9, 2006. A Pre-Hearing Conference was scheduled for February 10, 2006. Subsequently the Commission issued Order G-13-06 amending and finalizing the Regulatory Timetable. Following the submission of Information Requests by interested parties and responses by the Company, negotiations commenced on April 18, 2006. The Regulatory Timetable provided for a further process culminating in an oral public hearing if a Negotiated Settlement Agreement ("NSA") could not be reached.

FortisBC and a group of Intervenors concluded negotiations on April 19, 2006, leading to the settlement terms contained in this document and its appendices, and encompassing both the 2006 Revenue Requirements and a PBR Plan for the years 2007 to 2009 inclusive. A comprehensive list of issues considered in the negotiation of the 2006 Revenue Requirements, and their resolution, together with an Overview of 2006 Revenue Requirements and supporting

Schedules, is included as Appendix A to this document. The list of issues and resolution in regard to the PBR Plan is included as Appendix B.

The Parties to the NSA are:

- FortisBC Inc.;
- The British Columbia Old Age Pensioners Association et al.;
- Commercial Energy Consumers;
- The Interior Municipal Electricity Utilities;
- Natural Resource Industries and Hedley Improvement District;
- Buryl Slack, registered intervenor; and
- Alan Wait, registered intervenor.

The Parties' letters of support and comments of the NSA are attached as Appendix C.

<u>2006 Revenue Requirements</u>

2006 Revenue Requirements will become the base year for the PBR term, and was therefore reviewed in detail. The Company filed in a separate process in August 2005 its 2006 Capital Expenditure Plan ("CEP"), and Order G-8-06 dated January 31, 2006 substantially approved the CEP, resulting in just two capital projects to be disposed of during the Revenue Requirements process (see Appendix A, Issues 3 and 4). It was agreed by the Parties that the CEP applications will be dealt with in a separate process for the term of the PBR Plan.

Two significant accounting issues were addressed in the Application, both of which are issues that had not been reviewed in a number of years. The results of an expert-prepared Depreciation Study recommended changes to the depreciation rates of the Company's assets which have the effect of increasing the composite depreciation rate. The Company also reviewed its Capitalized Overheads policy and proposed a new methodology that more appropriately reflects the increased levels of corporate support for the extensive capital program underway. The Parties reached agreement on these two issues for 2006 and the subsequent PBR term, and also agreed to review these issues at the conclusion of the PBR term. The parties did not arrive at a principled decision on the appropriateness of the recommendations in the Depreciation Study or in the Capitalized Overheads Policy proposed by the Company and rather arrived at agreements on depreciation rates and the capitalized overheads on a negotiated basis. No precedent value is established by the settlement.

The provisions of the NSA for 2006 Revenue Requirements are itemized in Appendix A and, as seen on page 15 of Appendix A, result in a required general rate increase, effective January 1, 2006, equal to the existing interim increase of 5.9%.

As proposed in the Application, the sharing mechanism adopted for the PBR term will apply to the 2006 year, subject to the 2006 Performance Standards listed at page 14 of Appendix A. The sharing mechanism and the conditions related to Performance Standards are described in the following section, and in Appendix B.

Performance-Based Regulation Mechanism

The PBR Mechanism included in this Settlement Agreement resembles the Company's previous mechanism with regard to the rate-setting and Annual Review processes, except that Capital Expenditures will be tested in a separate process. Stakeholders have the opportunity to review and provide input to the Revenue Requirements by means of Information Request and workshop processes, during which the Company will provide explanations/justification for its forecasts.

For the term of the PBR, Gross Operating and Maintenance ("O&M") Expenses before Capitalized Overheads will be set annually by the formula set out in issue 2.3 of Appendix B incorporating a Growth Escalator (customer growth) and an Inflation Factor (the Consumer Price Index for British Columbia), minus an agreed Productivity Improvement Factor ("PIF"). PIFs of 2% in 2007, 2% in 2008 and 3% in 2009 (if PBR is extended) were agreed to, in recognition that FortisBC is in the early stages of its transition to a stand-alone, locally managed utility, and that progress in achieving efficiencies will accelerate throughout the term of the PBR.

Capitalized Overheads will also be determined annually by formula, at 20% of Gross O&M Expense. All other cost accounts will be forecast annually. The Capital Structure and Return on Equity as approved by Order G-52-05 and modified by Order G-14-06 will apply for the term of the PBR Plan.

In place of the previous multiple-component mechanism, the Parties agreed to a sharing based on actual financial performance compared to the Company's allowed ROE. All variances, positive or negative, equal to or less than 2.0%, will be shared equally between customers and the company. If the variance exceeds 2.0%, the excess will be placed in a deferral account for review at the next Annual Review. In addition to this safeguard, the 2008 Annual Review will include a review of the PBR mechanism, and the extension of the PBR Plan to 2009 will be contingent upon the mutual agreement of the Parties, as described in Appendix B, Issue 1.

The PBR Plan in this Settlement Agreement expands the number and range of non-financial Performance Standards from previous agreements, ensures a thorough review and analysis of annual performance, and provides a framework for determining eligibility for any incentives earned. Under this framework, failure to meet one (or more) performance standard(s) does not necessarily constitute unacceptable performance. When determining whether an incentive payment should be paid to FortisBC the Commission will take into account the reasons given by the Company on why certain performance targets were not met and why the Company should be entitled to an incentive payment. The ultimate decision as to whether the Company earns its incentive payment in a given year rests with the Commission.

Investigation into other possible measures to be included is included in the NSA, ensuring that the Company's Performance Standards will continue to evolve throughout the term of the PBR.

Further detail of the PBR Mechanisms is included in Appendix B.

Appendix A

FortisBC Inc. ("FortisBC" or the "Company")
2006 Revenue Requirements Application
Negotiated Settlement Agreement ("NSA")

<table>
<tr><th>FortisBC Application</th><th>Resolution</th><th>Reference</th></tr>
<tr><td>1. Load and Revenue Forecast

<table>
<tr><td>Load Forecast
• Residential
• General
• Industrial
• Wholesale
• Other
Total</td><td>Energy Sales(GWh)
1,080
589
369
935
58
3,031</td><td>Revenue ($000)
78,625
42,252
19,219
41,371
3,764
$185,541</td></tr>
<tr><td></td><td></td><td></td></tr>
</table></td>
<td>Residential revenue will be increased by 1% to $79.417 million.

All other components of load and revenue forecast accepted as filed.</td>
<td>Ex B-7, Tab 6a, 6b</td></tr>
<tr><td>2. Adjustment for Overstatement of 2005 Rate Base

In Exhibit B-7, Tab 5, page 30 the Company calculated an Adjustment for Overstatement of 2005 Rate Base. The Company proposes a direct offset of $349,000 to 2006 Revenue Requirements leaving 2006 Rate Base unchanged (Exhibit B-7, page 2). In response to BCOAPO 18a and BCUC 46.3.1 the Company indicated that it will include in the refund an adjustment for the 2005 Large Corporation Tax, and interest for 2005 on the over-collected revenues.</td>
<td>The Company will also include interest for a half year in 2006 on the $349,000 adjustment plus the LCT.</td>
<td>Ex B-7, Tab 5, p. 30; Ex B-7, p. 2; BCUC 46.3.1; BCOAPO 18a</td></tr>
<tr><td>3. Capital Expenditures – SAP Upgrade

FortisBC's 2006 Capital Expenditure Plan, filed in August 2005 was substantially approved via Commission Order G-8-06. The CEP included a project to convert the Company's SAP software to Great Plains. FortisBC later proposed to update SAP rather than convert to Great Plains.</td>
<td>2006 Rate Base will be reduced by $1.4 million to reflect the reduction in IT capital resulting from the SAP upgrade compared to the conversion.</td>
<td>• Cap Plan Aug. 16, 2006. p.9
• Ex B-7, Tab 5, p. 44
• Ex B-12 BCUC IR 47.2.1
• Ex B-7, Tab 5, p. 31; Ex B-9; BCUC 47.1; Commission Order G-8-06</td></tr>
</table>

4. Capital Expenditures – Vehicle Lease vs. Ownership The 2006 CEP proposed the buy-out of a number of existing leases of fleet vehicles. Order G-8-06 denied the Vehicle Lease to Ownership Conversion project subject to confirmation of a net benefit to customers. The analysis provided by the Company (Exhibit B-9) indicates a net benefit to owning the vehicles.	The $1.653 million expenditure to buy out the vehicle leases is approved.	• Cap Plan Aug. 16, 2006. p.9 • Ex B-7, Tab 5, p. 44 • Ex B-7, Tab 5, p. 31; Ex B-9; BCUC 47.1; Commission Order G-8-06
5. Financing Costs The Company's Forecast 2006 long-term embedded cost of debt is $25.096 million based on an embedded interest rate of 6.50% (Exhibit B-14, Tab 4, page 10, Schedule 5, lines 3 & 5). The Company's Forecast 2006 short-term cost of debt is $1.479 million. With an average principal of $20.518 million this results in an average interest rate of 7.21% ($1.479/20.518). The short-term debt is composed of Bankers Acceptance at 5.10%, Prime Loans at 5.68%, and Bank Fees of $350,000 (BCUC IR 48.5.1)	The long-term and short-term financing costs are accepted. FortisBC agrees to an interest deferral account to capture the difference between the actual 2006 interest costs and the forecast and to amortize the difference fully in 2007. The effect of the interest deferral account is that any difference between forecast and incurred interest will not affect the achieved ROE.	Ex B-7, Tab 5, pp.22-23
6. Pension, Post Retirement Benefits, Insurance, Trail Office Lease Cost Pension and Post Retirement Benefits have increased significantly as a result of the phased-in accrual amount for the 2005 and 2006 years as per the Commission's directive set out in Order No. G-52-05. The Company has indicated that these two items along with the lease costs from the Trail Office will be excluded from the O&M formula for the term of the PBR.	2006 Forecasts of Pension and Post-Retirement Benefits, Insurance expense, and the Trail Office lease costs are accepted as filed. These items will be excluded	• Ex B-12, BCUC IRs 84.6, 54.3.2, and 14 • Ex B-1 p.7, Ex B-12, BCUC IR 5.2, 6.0 • Ex B-12, BCUC IRs

	from the O&M formula.	11 &15.2 • Ex B-7 p.79, Table A2.5
7. Operating and Maintenance ("O&M") Expense Total Gross OM&A Expense is forecast to be $ 42,708 million in 2006, including the accounts in Item 6 above.	Gross O&M will be reduced by $0.8 million to $41,908	• Ex B-12, BCUC IRs 84.6, 54.3.2, and 14 • Ex B-1 p.7, Ex B-12, BCUC IR 5.2, 6.0 • Ex B-12, BCUC IRs 11 &15.2 • Ex B-7 p.79, Table A2.5
8. Materials Services Costs The Company proposes to allocate the cost of Materials Services (warehousing), which was referred to in the application as Procurement costs, to capital and O&M proportionately with the materials used.	The change in allocating materials services costs is accepted. The change results in an increase $0.8 million of allocations to capital.	
9. Income Tax FortisBC records deferred charges on a net-of-tax basis. Additions to deferred charges are included in the timing differences, gross of tax, with an offsetting tax effect, resulting in net zero tax expense (Exhibit B-1, Tab 4, page 6 Schedule 3, lines 13 and 30). Terasen Gas Inc. does not include additions for deferred charges in its income tax schedule.	FortisBC agrees to use the Terasen Gas Inc. method of calculating Income Tax Expense for deferred charge net of tax additions.	Ex B-12, BCUC IR 18 Ex B-7 Tab 5, p.63
10. AFUDC Rate for 2006 Based on FortisBC's allowed Return on Equity of 9.20% and its forecast Weighted Average Cost of Debt, the AFUDC rate for 2006 is 6.26% (BCUC IR 54.1.4), rounded to 6.3%.	The AFUDC rate of 6.3% is accepted.	• Ex B-12; BCUC 54.1.4
11. Application of AFUDC to Capital Projects FortisBC has historically applied AFUDC only to projects of at least three months' duration and costing more than $100,000. The company proposes to remove these criteria with one exception. AFUDC would not be calculated on small distribution projects such as new customer connects and urgent repairs.	The existing thresholds of three months' duration and $100,000 will continue to apply. AFUDC is reduced by $30,000.	• Ex B-7, Tab 5, p. 76; BCUC 55.1-55.2

<table>
<tr><td>

12. Capitalized Overhead

The Company proposes to change its capitalized overhead methodology to one based on the principles of activity-based costing. The proposed methodology includes indirect overhead costs not previously allocated to capital expenditures (Exhibit B-1, Tab 5 page 66).

FortisBC proposes capitalized overhead of $11.736 million in 2006, 27.5% of Gross O&M expenses.
</td><td>Capitalized Overhead is set at 20% of forecast Gross O&M for 2006, or $8.382 million. The forecast will be the actual Capitalized Overhead for the year.</td><td>Ex B-7, Tab 5, pp. 77-80; BCUC 56.1-56.13</td></tr>
<tr><td>

13. Other Income

(Exhibit B-1, Tab 5, page 15)

<table>
<tr><td></td><td>($000s)</td></tr>
<tr><td>• Apparatus and Facilities Rental</td><td>2,034</td></tr>
<tr><td>• Contract Revenue</td><td>1,816</td></tr>
<tr><td>• Miscellaneous Revenue</td><td>534</td></tr>
<tr><td>• Investment Income</td><td>334</td></tr>
<tr><td>Total</td><td>4,718</td></tr>
</table>
</td><td>Investment Income is adjusted to $350,000. Other components are accepted as filed. Total Other Income is $4.734 million.</td><td>Ex B-7, Tab 5, p.60, Table 2-G</td></tr>
<tr><td>

14. Depreciation Expense

FortisBC applies to implement depreciation rate changes based on the results of a Depreciation Study performed by Gannett Fleming (see response to BCUC IR 52.1.1). The proposal includes:

a. New proposed rates resulting in a composite depreciation rate of 3.6% for 2006;
b. Amortization of the $3.091 million Rate Stabilization Account (“RSA”) at 3.4% based on the composite life for transmission assets;
c. Aggregation of Plants 1, 2, 3 and 4 into a single classification for depreciation purposes; and
d. A change from “mass property group accounting” to “amortization accounting” for Accounts 391, 391.1, 394 and 397 (see response to BCUC IR 57.5)
</td><td>The Company and Participants agreed to change the proposed depreciation rates for six accounts: 353.0, 355.0, 356.0, 364.0, 365.0, and 390.1 are adjusted to 3.0% in order to reflect longer average service lives for those assets.

The RSA is to be amortized over a ten-year period beginning in 2006.

Aggregation of Plants 1, 2, 3 and 4 is accepted.

Amortization accounting for Accounts 391, 391.1, 394 and 397 is accepted.</td><td>• Ex B-12, BCUC A52.1.1
• Ex B-7, Tab 5, p. 71
• Ex B-7, Tab 5, p. 70
• Ex B-12, BCUC 57.5</td></tr>
</table>

	The Company and the Participants hold differing views on negative salvage values in the depreciation study. The Parties agree to defer analysis of the issue of negative net salvage value in the depreciation study for the term of the PBR ending in 2008 or 2009. The parties did not agree that the findings of the Depreciation Study were otherwise appropriate and no precedent value is attached to the Depreciation Study. The current practice of depreciating assets based on Plant in Service at the beginning of the year will continue.	
15. Amortization of Demand Side Management Expenditures The Company proposes to change the amortization period for its DSM expenditures from 8 years to 10 years in aggregate, based on a weighted amortization of individual program lives (Exhibit B-1, Tab 5, page 61 and Tab 10 Appendix C). Individual programs have lives ranging from 5 to 30 years, with a weighted amortization period of 11 years. BC Hydro: a. amortizes the Power Smart costs to appropriately match the costs with the energy savings benefits over future years, but in any case not to exceed 10 years. b. Costs incurred by BC Hydro in the concept development phase are not capitalized. Program-specific and non-specific portfolio development and implementation costs are capitalized and amortized	Program costs up to and including 2005 will continue to be amortized over the existing 8 year period. 2006 and future costs will be amortized in a manner consistent with BC Hydro. Concept development costs will continue to be capitalized. Amortization commences in the year following the expenditure, as currently. DSM expenditures	• Ex B-1, Tab 5, p.61, Tab 10 • Ex B-12, BCUC IR 26.2.1

over the period of benefit of the respective programs. c. BC Hydro commences amortization in the year following the year in which the expenditure is incurred. d. DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled.	associated with cancelled programs are written off in the year in which the program is cancelled. FortisBC is to file a continuity schedule pre- and post changes to the amortization rates.	
16. 2006 DSM Capital Expenditures 2006 DSM capital expenditures are forecast at $2.236 million (Exhibit B-7, Tab 10, page 3)	The 2006 DSM expenditures are approved.	• Ex B-7, Tab 10, p.3 • Ex B-1, Tab 10, p.7

17. DSM Incentive for 2006 The DSM Technical Committee proposed (Exhibit B-13, page 8): a. Continuation of the DSM incentive mechanism subject to a change in the net benefits baseline to the average of the last three years' actual net benefits; b. Change in the calculation of gross benefits from a fixed 1999 BC Hydro Rate 3808 to the prevailing rate; and c. Implementing two avoided capacity rates, one for heat sensitive and another for non heat sensitive programs.	The proposal to change the calculation of the net benefits baseline to the average of the last three years' actual net benefits is accepted. The 1999 value for RS 3808 will be changed to the prevailing rate for calculating gross benefits. The implementation of two avoided capacity rates is not accepted. FortisBC agrees to provide further information on this proposal at its 2006 Annual Review.	• Ex B-5 • Ex B-12 BCUC IR 44.3.2, NRI Q3 • Willis Energy Comments 03/17/2006
18. Aesthetic and Environmental Upgrades Program (AEUP) The AEUP is a new initiative similar to BC Hydro's Beautification program, with a proposed annual budget of $100,000 to be awarded to up to 10 participants. (Exhibit B-1. Tab 11, page 2).	The program is accepted as proposed. It will be implemented for the last half of 2006 with a budget of $50,000.	• Ex B-1 Tab 11, p.2 • Ex B-12, BCUC IR 73

	Project details and actual expenditures will be provided on an annual basis.	
19. Power Purchase and Wheeling Expense Power Purchase Expense of $65.067 million and Wheeling Expense of $3.742 million are forecast for 2006. (Exhibit B-7 Tab 7 Update). The Company proposes that, as in previous years, any changes to the BC Hydro rates will be flowed through to customers. FortisBC forecasts 185 MW of BC Hydro capacity at peak. This allows an additional 15 MW to be used for required reserve capacity.	Power Purchase Expense and Wheeling Expense accepted as filed. Flow-through treatment for BC Hydro rate increases is approved.	• Ex B-7 Tab 2, p.3 • Exhibit B-2 BCUC IR 23, • Exhibit B-13, Power Purchases Technical Committee Report, page 3.
20. Technical Committees The Application proposes that Technical Committees will be struck to review its Load Forecast, Power Purchase Expense, and DSM Expenditure Forecast, prior to the Revenue Requirements workshop.	The Parties agree that the Load Forecast and Power Purchase Expense forecast will be examined through the workshop and IR process without the use of technical committees. The DSM Incentive Committee will be renamed the DSM Advisory Committee to recognize the greater impact of its advice and to review Power Sense planning and target setting. BCUC staff will serve *ex officio.*	• Ex B-1 Tab3, p.6 • Ex B-12. BCUC IR 25.1 • Technical Committee material / minutes
21. 2005 Resource Plan Action Plan Commission Order G-52-05 directed FortisBC to file status updates on the progress of negotiations with BC Hydro in regard to the Power Purchase Agreement, and on the progress of its study of a new market strategy.	FortisBC will file with the Commission, and provide to intervenors, the requested reports.	May 31, 2005 Decision on 2005 Resource Plan p.68

22. Revenue Protection Project 2005 deferred costs for the Revenue Protection project are \$146,500, and forecast 2006 costs are \$598,000. The Company proposes to amortize the costs over five years.	2005 costs are to be fully amortized in 2006. 2006 costs in the amount of \$300,000 are approved and will be amortized in the following year. The Company will report annually on the costs and tangible benefits of the program.	Ex B-7, Tab 5, pp. 34-35; BCUC 20.1-20.3 & 21.1
23. Deferred Charges a. 2005 Revenue Requirements - \$705,000 b. 2006 Revenue Requirements - \$225,000 c. 2007 Revenue Requirements - \$150,000 d. BC Hydro Rate Design - \$150,000 e. Terasen Gas ROE Application - \$ 75,000 f. CCA Rate Change Deferral - \$503,000	The Company will provide further variance explanation for the 2005 Revenue Requirements to Commission Staff. If approved, the costs will be amortized over a four year period beginning in 2006. An explanation for the 2006 Revenue Requirements General and Staff Expenses will be provided to Commission Staff. The costs are to be amortized over three years beginning in 2007. Forecast costs for the 2007 Revenue Requirements application are accepted. Costs for the BC Hydro Rate Design Application are removed from the forecast as the Application is not expected to be filed before late 2006. The Company will provide detail of consulting and	• Ex B-7, Tab 5, pp. 32-33 & 46 (lines 12-13); BCUC 19.1 • Ex B-7 Tab 5, p. 46 Table 1 – B (2006), line 12-13; BCUC 19.3.1

	legal costs incurred in the Terasen Gas ROE Application to Commission Staff. Costs are to be fully amortized in 2006. The CCA Rate Deferral Account will remain in Rate Base pending outcome of the legislation. If the legislation is not enacted prior to the 2006 Annual Review, the Company will bring forward a proposal for the disposition of the deferral account.	
24. CWIP Attracting AFUDC in Rate Base FortisBC includes CWIP subject to AFUDC in Rate Base, and reduces Revenue Requirements by the amount of AFUDC. Other Canadian utilities include only CWIP not subject to AFUDC in Rate Base and calculate interest expense and the cost of equity only on Plant in Service and other costs approved for Rate Base treatment (Exhibit B-1 Tab 5, page 62).	CWIP will be included in Rate Base for 2006. Beginning in 2007 the Company will change to the method used by other utilities.	Ex B-7, Tab 5, pp. 73-75; BCUC 53.1-53.4

25. 2006 Performance Standards

The following Performance Standards are proposed, using an October 1 to September 30 year (Exhibit B-1 Tab 9a):

Performance Standard	Proposed Target
SAIDI	3.14
SAIFI	3.01
Forced Outage Rate	0.50%
Billing Accuracy	0.075% of bills rejected by system
Commitment to read meters	95% of meters read as scheduled
Contact Center Performance	70% of calls answered within 30 sec
Emergency Response Time	85% response within 2 hours
Residential Service Connections	85% in less than 6 working days
Extensions - Time to Quote	75% in less than 35 working days
Extensions - Time to Complete	75% in less than 30 working days
All Injury Frequency Rate	4.83
Injury Severity Rate	24.62
Recordable Vehicle Incidents	4.72
Customer Survey	Informational only

The proposed measures and timeframe are accepted.

Target
3 year average of 2.62 + 10% = 2.88
3 year average of 2.51 + 10% = 2.76
0.35%
0.072%
97%
70% of calls answered within 30 seconds.
85% response within 2 hours
85% in less than 6 working days
75% in less than 35 working days
75% in less than 30 working days
4.83
24.62
4.72
To be included as a performance standard. Directional measure only.
The Company will investigate a means of measuring First Contact Resolution and present results at the 2006 Annual Review

Appendix A

Revenue Requirements Overview

		Approved 2005	**Increase or (Decrease)**	**2006**
			($ 000s)	
1	Sales Volume (GW.h)	2,924		3,031
2	Rate Base (000s)	597,688		675,906
3	Return on Rate Base	7.69%		7.60%
4				
5	**REVENUE DEFICIENCY**		($000s)	
6				
7	**POWER SUPPLY**			
8	Power Purchases	59,451	5,616	65,067
9				
10	**OPERATING**			
11	O&M Expense	39,629	2,279	41,908
12	Capitalized Overhead	(3,396)	(4,986)	(8,382)
13	Wheeling	3,878	(136)	3,742
14	Other Income	(3,970)	(764)	(4,734)
15		36,141	(3,607)	32,534
16	**TAXES**			
17	Property and Capital Taxes	9,986	687	10,673
18	Water Fees	7,681	698	8,379
19	Income Taxes	5,581	(93)	5,488
20		23,248	1,292	24,540
21	**FINANCING**			
22	Cost of Debt	23,443	3,080	26,523
23	Cost of Equity	22,544	2,329	24,873
24	Depreciation and Amortization	18,789	7,951	26,740
25	AFUDC	(3,005)	984	(2,021)
26		61,771	14,344	76,115
27				
28	**INCENTIVE ADJUSTMENTS**	(1,791)	1,316	(475)
29				
30	**TOTAL REVENUE REQUIREMENT**	178,820	18,961	197,781
31				
32	OF WHICH LOAD GROWTH:			
31				
32	Adjustment for Overstatement			
33	of 2005 Rate Base			(377)
34				
35	ADJUSTED REVENUE REQUIREMENT			197,404
36	**Less: REVENUE AT APPROVED RATES**			186,327
37	**REVENUE DEFICIENCY for Rate Setting**			11,077
38				
39	**RATE INCREASE**			**5.9%**

Appendix A

SCHEDULE 1
UTILITY RATE BASE

		Note	Actual 2004	Actual 2005	Forecast 2006
				($ 000s)	
1	Plant in Service, January 1		630,676	709,762	820,436
2	Net Additions		79,086	110,674	107,816
3	Plant in Service, December 31		709,762	820,436	928,252
4	Construction Work in Progress	1.	39,946	39,359	30,613
5	Plant Held for Future Use		-	-	-
6	Plant Acquisition Adjustment		11,912	11,912	11,912
7	Deferred and Preliminary Charges		14,773	16,972	17,083
8			776,393	888,679	987,860
9	Less:				
	Accumulated Depreciation				
10	and Amortization		184,560	198,524	216,720
11	Contributions in Aid of Construction		53,661	58,924	63,295
12			238,221	257,448	280,015
13	Depreciated Rate Base		538,172	631,231	707,845
14	Prior Year Depreciated Utility Rate Base		456,285	538,172	631,231
15	Mean Depreciated Utility Rate Base		497,229	584,702	669,538
16					
17	Allowance for Working Capital		5,235	8,633	7,662
18	Adjustment for Capital Additions		(3,489)	(3,490)	(1,294)
19	Mid-Year Utility Rate Base		498,974	589,845	675,906

20 Note 1. In 2005, FortisBC reclassified its inventory purchased for capital projects, in accordance with the Uniform System of Accounts, to Account No. 107. Previously this inventory was included in Account No. 154, Materials and Supplies.
2004 Rate Base has been restated to reflect this change, which has the effect of increasing Construction Work in Progress by $4.5 million, and reducing the Allowance for Working Capital by an approximately equal amount. The net impact on Rate Base is zero.

Appendix A

SCHEDULE 2
EARNED RETURN

		Actual 2004	Actual 2005	Forecast 2006
			($ 000s)	
1	SALES VOLUME (GW.h)	2,874	2,969	3,031
2				
3	ELECTRICITY SALES REVENUE	174,881	183,120	197,781
4				
5	EXPENSES			
6	Power Purchases	59,014	60,404	65,067
7	Wheeling	3,817	3,956	3,742
8		62,831	64,360	68,809
9				
10	Operating Expenses	36,042	37,680	33,526
11				
12	Taxes			
13	Property Tax	10,047	9,540	10,673
14	Water Fees	7,399	7,679	8,379
15		17,446	17,219	19,052
16				
17	Depreciation and Amortization	16,817	18,840	26,740
18				
19	Other Income	(4,472)	(4,342)	(4,734)
20	AFUDC	(2,434)	(3,335)	(2,021)
21	Incentive Adjustments	(2,300)	(1,219)	(475)
22	UTILITY INCOME BEFORE TAX	50,951	53,917	56,884
23	Less:			
24	INCOME TAXES	8,333	7,148	5,488
25				
26	RETURN ON RATE BASE	42,618	46,769	51,396
27				
28	Utility Rate Base	498,974	589,845	675,906
29	Return on Rate Base	8.54%	7.93%	7.60%

Appendix A

SCHEDULE 3
INCOME TAX EXPENSE

		Actual 2004	Actual 2005	Forecast 2006
			($ 000s)	
1	UTILITY INCOME BEFORE TAX	50,951	53,917	56,884
2	Deduct:			
3	Interest Expense	19,033	22,389	26,523
4	ACCOUNTING INCOME	31,918	31,527	30,361
5	Deductions			
6	Capital Cost Allowance	19,020	22,760	31,555
7	Capitalized Overhead	2,563	3,392	8,382
8	AFUDC	2,434	3,335	2,021
9	Net Deductable Deferred Charge Additions	3,036	3,412	-
10	Incentive & Revenue Deferrals	2,284	1,219	475
11	Financing Fees	229	766	766
12	All Other (net effect)	(155)	265	120
13		29,411	35,149	43,319
14				
15	Additions			
16	Amortization of Deferred Charges	1,849	1,873	2,236
17	Depreciation	14,969	16,967	24,504
18		16,818	18,840	26,740
19				
20	TAXABLE INCOME	19,324	15,219	13,782
21				
22	Tax Rate	35.62%	34.87%	34.12%
23				
24	Taxes Payable	6,883	5,307	4,703
25	Prior Years' Overprovisions/(Underprovisions)	(208)	(8)	-
26	Tax Impact of Deferred Charges	789	1,334	105
27	Large Corporations Tax	819	865	680
28	Allowance for tax audit	50	(350)	-
29				
30	REGULATORY TAX PROVISION	8,333	7,148	5,488

Note: At line 26, Tax Impact of Deferred Charges for the year 2006 refers to the tax effect of deferred debt issue costs only.

Appendix A

SCHEDULE 4
COMMON SHARE EQUITY

		Actual 2004	Actual 2005	Forecast 2006
			($000s)	
1	Share Capital	76,500	106,500	128,000
2	Retained Earnings	114,487	128,346	144,726
3				
4	COMMON EQUITY - OPENING BALANCE	190,987	234,846	272,726
5				
6	Less: Common Dividends	(9,726)	(8,000)	(10,000)
7				
8	Add: Net Income	23,585	24,380	24,873
9	Shares Issued	30,000	21,500	-
10				
11	COMMON EQUITY - CLOSING BALANCE	234,846	272,726	287,599
12				
13	SIMPLE AVERAGE	212,917	253,786	280,162
14				
15	Adjustment for Shares Issued	7,603	(6,934)	-
16	Deemed Equity Adjustment	-	-	(9,799)
17				
18	COMMON EQUITY - AVERAGE	220,519	246,851	270,363

Note: The opening balance for 2004 Retained Earnings has been restated. Previously it included an adjustment for weather normalization of the previous year's income in the amount of $(155,000). The restatement has the effect of increasing average common equity by $155,000 in each year. The rate of Return on Equity is unchanged.

Appendix A

SCHEDULE 5
RETURN ON CAPITAL

		Actual 2004	Actual 2005	Forecast 2006
1	Secured and Senior Unsecured Debt	159,331	300,607	385,968
2	Proportion	31.09%	50.80%	57.10%
3	Embedded Cost	7.93%	6.75%	6.50%
4	Cost Component	2.47%	3.43%	3.71%
5	Return	12,637	20,278	25,096
6	Short Term Debt	132,575	44,317	19,575
7	Proportion	25.87%	7.49%	2.90%
8	Embedded Cost	4.82%	4.76%	5.50%
9	Cost Component	1.25%	0.36%	0.16%
10	Return (including fees)	6,396	2,111	1,427
21	Common Equity	220,519	246,851	270,363
22	Proportion	43.03%	41.71%	40.00%
23	Embedded Cost	10.70%	9.88%	9.20%
24	Cost Component	4.60%	4.12%	3.68%
25	Return	23,585	24,380	24,873
26	TOTAL CAPITALIZATION	512,425	591,775	675,906
27	RATE BASE	498,974	589,845	675,906
28	Earned Return	42,618	46,769	51,396
29	RETURN ON CAPITAL	8.32%	7.90%	7.60%
30	RETURN ON RATE BASE	8.54%	7.93%	7.60%

Note: The Common Equity component of Capitalization in each year has been re-stated (see Note to Schedule 4). The restatement has the effect of increasing average common equity by $155,000 in each year. The rate of Return on Equity is unchanged.

FortisBC Inc. ("FortisBC" or the "Company")
Performance Based Regulation ("PBR") Mechanism
Negotiated Settlement Agreement ("NSA")

PBR - Application Requests (Exhibit B-1, Tab 3)	**Resolution**	**Reference**
1. Term of the Proposed PBR The NSA for the 2006 Revenue Requirements will be the basis for a PBR mechanism for 2007 – 2009. Performance Standards and the incentive mechanism will apply in 2006.	The PBR term of 2007-2008 is accepted, with an option to extend the term to 2009 under the terms set out in Appendix B, if the Company and its stakeholders agree to the extension. The Parties agree to conduct a review of the PBR mechanism during the 2008 Annual Review. Intervenors will provide input as to how the review will take place. At the 2008 Annual Review, the Company and its stakeholders will determine whether to extend the PBR term until 2009. For the purposes of this determination stakeholders will mean the registered intervenors at the 2008 Annual Review. If a consensus is not reached among the stakeholders on whether to continue using the PBR mechanism for 2009, the matter will be determined by the Commission, after hearing submission from the Parties. In the event that PBR is not extended, FortisBC will file a Revenue Requirements Application for 2009 rates, subject to any Order of the Commission.	Exhibit B-1, Tab3, P.2, lines 5 & 6; Exhibit B-12, BCUC IR 74.0 and 76.1; CEC IR 3.0

2. Determination of Annual Revenue Requirements The Company will file a Preliminary Revenue Requirements Application in October of each year, or earlier, to set rates for the subsequent year. The Application will be followed by a workshop to be held in conjunction with the Annual Review, and will be followed by a Negotiated Settlement Process. Individual Cost Accounts will be determined as described in the following sections:	The conceptual framework proposed by FortisBC is accepted for 2006, 2007, and 2008. For 2009, in the event that the PBR period is not continued, FortisBC will file a revenue requirement application for the setting of 2009 rates.	Exhibit B-1, Tab 3, P.6, lines 13 to 17; Exhibit B-12, BCUC IR 83.0; CEC IR 9.0
2.1 The Application proposes that these line items will be reviewed annually by technical committees. • Load Forecast • Power Purchase Expense • Demand Side Management	The Load Forecast and Power Purchase Expense forecast will be reviewed through the Revenue Requirements workshop and Information Request processes and approved annually by the Commission. There will be no Technical Committees. The DSM Incentive Committee will be renamed the DSM Advisory Committee, and will review and make recommendations at the Annual Review in regard to annual DSM expenditures. Amortization of DSM expenditures, beginning in 2007, will be consistent with the practice of BC Hydro, as described in Issue 15 of the 2006 Revenue Requirements NSA.	• Exhibit B-1, Tab 3, P.6, lines 20 to 23 • Ex B-1, Tab 5, p.61, Tab 10 • Ex B-12, BCUC IR 26.2.1
2.2 Capital Expenditures The Application proposes that its annual Capital Expenditure Plans (CEP) will be approved as part of a separate annual filing or update, subject to application for a CPCN for major projects as directed by the Commission	A separate application process for the Company's Capital Expenditure plans is accepted. The amount of the net addition brought into Rate Base along with the AFUDC calculation will	Exhibit B-1, Tab 3, P.7, lines 1 to 3

	be examined at the Revenue Requirements Workshop and approved by the Commission's subsequent Order. For information purposes only, operating savings claimed in the 2006 and future CEP and CPCN applications will be tabulated and presented at each Annual Review.	
2.3 Gross Operating & Maintenance ("O&M") Expenses O&M Expenses for the years 2007 to 2009 will be determined by formula, similar to the previous PBR mechanism. 2006 Base O&M will be adjusted using a Cost Escalator and a Growth Escalator. A Productivity Improvement Factor will be negotiated for the term of the PBR.	The proposed formula method for determining 2007 to 2009 Gross O&M expense is accepted, subject to the conditions for individual components described in the following sections.	Exhibit B-1, Tab 3, P.6, lines 24 to 30
2.3.1 Determination of Base amount for Gross O&M expenses / customer The proposed formula is: O&M = Cost/Customer x BC CPI x Customer Growth x PIF Pension and Post Retirement Benefits and the lease costs for the Trail Office are excluded from the Base O&M calculation.	The proposed formula is accepted. The base Cost/ Customer is determined by 2006 Gross O&M expense arising from the 2006 Revenue Requirements NSA, excluding Pension and Post Retirement Benefits and the Trail Office lease costs.	Exhibit B-5, Proposed Mechanism, Slide #8; Exhibit B-12, BCUC IR 84.6
2.3.2 Cost Escalator (CPI) The Company proposes to use the forecast BC CPI for the Cost Escalator, and to reforecast for each year of the PBR term.	BC CPI is accepted as the Cost Escalator. The forecast will be the average of the most recent forecasts from the Conference Board of Canada, the BC Ministry of Finance, the RBC Financial Group, and the Toronto-Dominion Bank. There is no true-up of target O&M expense for actual CPI.	Exhibit B-1, Tab 3, P.6, lines 24 to 30; Exhibit B-12, BCUC IR 76.1 & 84.5

2.3.3 Growth Escalator Forecast average annual customer growth is proposed as the Growth Escalator. Each year's forecast will be updated with the most recent actual customer count.	The proposal is accepted. There is no true-up of target O&M expense for actual customer growth.	Exhibit B-1, Tab 3, P.6, lines 24 to 30; Exhibit B-12, BCUC IR 24.1, 84.4
2.3.4 Productivity Improvement Factor (PIF) The Company proposes PIFs of: 1% for 2007 2% for 2008 3% for 2009	The Parties agree to PIFs of: 2% for 2007 2% for 2008 3% for 2009 (if PBR is extended)	Exhibit B-1, Tab 3, P.6, lines 24 to 30; Exhibit B-12, BCUC IR 84.1, 84.2, 84.3; BCUC Decision, dated May 31, 2005
2.3.5 Pension and Post-Retirement Benefits and Trial Office Lease Cost The cost of Pension and Post-Retirement Benefits are forecast to increase substantially in 2007, partially as a result of FortisBC's phase-in of accrued liability as directed in Order G-52-05. The Trail Office lease costs, as approved by Order G-41-94, will increase substantially in 2008. The Company proposes to exclude these items from the calculation of Gross O&M and to forecast them annually for determining Revenue Requirements.	Pension and Post Retirement Benefits, and the Trail Office lease costs will be excluded from Base O&M and approved annually.	Exhibit B-12, BCUC IR 84.6
2.3.6 Capitalized Overhead	Capitalized Overhead is set at 20% of forecast Gross O&M for the term of the PBR. The forecast will be the actual Capitalized Overhead for each year. The parties acknowledge that the Capitalized Overhead Policy is premised on the extensive capital	None

	program that FortisBC is currently undertaking, therefore the Company's Capitalized Overhead methodology will be reviewed at the end of the PBR term.	
2.4 All other Cost of Service Line Items All other cost of service line items will be forecast by the Company and subject to review at the annual Revenue Requirement Workshop	The proposal is accepted, subject to conditions for the Annual Review and Revenue Requirements workshops described in Issue 5.	Exhibit B-1, Tab 3, P.7, lines 4 and 5
3. Type of PBR sharing mechanism The proposed mechanism is "collared ROE" mechanism which creates a true incentive based on overall actual financial performance compared to the Company's allowed ROE	The general form of the ROE sharing mechanism is accepted subject to the following.	Exhibit B-1, Tab 3, P.2, lines 8 to 30
3.1 Detailed aspects of the ROE sharing mechanism The Application proposes sharing the actual earnings in excess of the target ROE according to a graduated formula: • A symmetrical dead band of 0.5% around the approved ROE, adjusted for tax, to the account of the shareholders • The next band of 1.5% to be shared equally between customers and the Company • Differences in ROE greater than 2.0% are to be placed in a deferral account for review and disposition at the next Annual Review.	There will be no deadband. Within a 2% band around the approved ROE, customers and the shareholder will share equally any positive or negative variance, adjusted for income tax. Differences in ROE greater than 2.0% are to be placed in a deferral account for review and disposition at the next Annual Review.	Exhibit B-1, Tab 3, P.3, lines 1 to 23; Exhibit B-12, BCUC IR 78, 79, 80; Exhibit B-12, CEC IR 5
3.2 Demand Side Management – Incentive Mechanism Proposal The DSM Technical Committee proposed (Exhibit B-13, page 8): e. Continuation of the DSM incentive	As described in Issue 17 of the 2006 Revenue Requirements NSA, the change in the net	Exhibit B-1, Tab 10, P.P. 13 to 15

mechanism subject to a change in the net benefits baseline to the average of the last three years' actual net benefits; f. Change in the calculation of gross benefits from a fixed 1999 BC Hydro Rate 3808 to the prevailing rate; and g. Implementing two avoided capacity rates, one for heat sensitive and another for non heat sensitive programs.	benefits baseline to the 3-year average, and the use of the prevailing RS 3808 are accepted. The proposal to implement two avoided capacity rates is not accepted at this time. FortisBC agrees to provide further information on this proposal at its 2006 Annual Review where the issue will be reviewed.	
3.3 Gross Annual Interest Expense and the Interest Component of AFUDC	Positive or negative variances in the gross annual interest expense and the interest component of AFUDC will be excluded from the collared ROE sharing mechanism. In other words these expenses will be treated as flow-through expenses to customers in the same manner as in 2005.	BCUC Decision, dated May 31, 2005; Letter L-97-05; Order No. G-129-05
3.4 Process for dealing with Extraordinary Items FortisBC proposes that extraordinary items be handled outside of the ROE sharing mechanism. Examples of extraordinary items are initiatives that the Company may propose for mutually beneficial items where investment recovery would exceed the term of the PBR. Such a mechanism will provide an incentive to undertake projects which would not otherwise return a benefit because of the limited term of the PBR. If FortisBC has an initiative that would fit this category, it is envisioned that the Company would make this proposal as part of its annual rate filing application which would then be subject to discussion, negotiation and disposition at the Annual Review.	The Company's proposal is accepted.	Exhibit B-1, Tab 3, P.3, lines 25 to 30; Exhibit B-12, BCUC IR 81.0

3.5 "Z" Factor Provision A "Z" factor provision is proposed to permit recovery or refund of extraordinary costs outside of the "steady state" operations as determined by the formula described for Base O&M expenses. "Z" factor circumstances limited to the following: • Directives of the BCUC or other competent regulatory agencies; • Acts of legislation or regulation of government; • Changes due to Generally Accepted Accounting Principles; • Changes to actuarial evaluations; • Force Majeure events; • Other extraordinary events as agreed to by the parties in the Negotiated Settlement Process. Where possible the items will be included in Revenue Requirements. In unforeseen circumstances the costs will be captured in a deferral account for consideration and disposition as part of the Annual Review.	The "Z "Factor provision is approved. FortisBC will comply with GAAP unless a variance is ordered by the Commission.	Exhibit B-1, Tab 3, P.4, lines 13 to 15 and P.5, lines 1 & 2; Exhibit B-12, BCUC IR 82.0
4. Type of Performance Standards The proposed Performance Standards are listed in Exhibit B-1, Tab 9a, Page 3 and listed individually below. Performance will be measured on the basis of the twelve-month period October 1 to September 31, to ensure that a full year of information is available at the Annual Review.	The list of Performance Standards is accepted, subject to the conditions described in this Section. The Oct. 1 to Sept. 30 timeframe is accepted for all Performance Standards. To be eligible for an incentive, FortisBC must show that it did not achieve the additional earnings as a direct result of deteriorated performance. It is also accepted that the failure to meet one or more performance targets will not necessarily result	Exhibit B-1, Tab 9a, P.3, line 1

	in disallowing the incentive payment. When determining whether an incentive payment should be paid to the Company the Commission will take into account the reasons given by the Company on why certain performance targets were not met and why the Company should be entitled to an incentive payment. FortisBC is accountable for its quality of service by reporting on its performance at the annual reviews, with an opportunity for stakeholders to argue to the Commission that FortisBC should not be awarded an incentive payment if the service quality has deteriorated. The final determination and decision for allowance/ disallowance of the incentive rests with the Commission.	
4.1 Targets for Performance Standards – Reliability The Application proposes the following targets: System Average Interruption Duration Index (SAIDI) 3.14 System Average Interruption Frequency Index (SAIFI) 3.01 Generator Forced Outage Rate (FOR) 0.50% Targets are to be adjusted on an annual basis by recalculating the normalized 3 year average and increasing it by 20% to account for annual variability and increased reliability exposure related to implementing the Capital Plan.	SAIDI and SAIFI targets will be calculated using the normalized results for the last three years, normalized. In 2006, the normalized results for each of 2003, 2004, and 2005 will be increased by 10% before averaging. The 10% cushion will be phased out as follows: In 2007, the average will consist of the actual results plus 10% for each of 2004 and 2005, and actual results for 2006. In 2008, the actual results plus 10% for 2005, and actual results for 2006	Exhibit B-1, Tab 9a, P.3, line 1; P.6, lines 16 to 19; P. 6, lines 21 to 26; P.7, lines 2 to 16

	and 2007 will make up the average. In 2009, the target will be the average of the actual results for 2006, 2007, and 2008. The Generator Forced Outage Rate is set at 0.35% for the term of the PBR.	
4.2 Targets for Performance Standards – Customer Service The proposed targets are:	Accepted:	Exhibit B-1, Tab 9a, PP. 9 to 13, Exhibit B-12, BCUC IR 59.0, 61.0, 62.0, 65.0, 66.0, 67.0.
Billing Accuracy – 0.075% of bills rejected by system	0.072% the PBR term.	
Commitment to Read Meters as Scheduled - 95% of meters read as scheduled.	97% for the PBR term	
Contact Center Performance - 70% of calls answered within 30 seconds	70% within 30 seconds for the PBR term	
Emergency Response Time - 85% of trouble calls responded to within 2 hours	85% within 2 hours for the PBR term	
Completion Time for New Requests Residential Std. Service Connections - 85% completed within 6 working days	85% within 6 working days for the term	
Residential Service Extensions Initial Contact to Quote – 75% completed within 35 working days Customer Acceptance to Construction Completion	75% in 2006 for Initial Contact to Quote and for Acceptance to Construction Completion. Phase in 3-year rolling average as results are available.	
75% completed within 30 working days	The Company agrees to research First Contact Resolution and to report at the 2006 Annual Review.	

4.3 Targets for Performance Standards – Health & Safety The proposed targets are: All Injury Frequency Rate (AIFR) 4.83 Injury Severity Rate (ISR) 24.62 Recordable Vehicle Incidents (RVI) 4.72	The targets will be set using a rolling 3-year average. For 2006: AIFR - 4.83 ISR - 24.62 RVI - 4.72	Exhibit B-1, Tab 9a, PP. 14 to 17
4.4 Informational Metrics – Customer Survey FortisBC proposes to present the results of its Customer Survey at the Annual Reviews, but that the results would not form part of the Performance Standards for incentive purposes.	The Customer Survey results will be a Performance Standard for consideration of incentives, but will be a directional measure only. No targets will be set. FortisBC agrees to research possible measures for First Contact Resolution provide results at the 2006 Annual Review.	Exhibit B-1, Tab 9a, P. 18; BCUC IR 63.0
5. Process – Annual Review, and Negotiated Settlement & Revenue Requirements Workshop Annual Review, Revenue Requirement Workshop and Negotiated Settlement Process according to the agenda and timetable set out in BCUC IR 83.1: For setting 2007 rates, the proposed process is; October 2 Application filed October 27 Information Requests received November 10 Responses to IRs November 14 2006 Annual Review November 23 Technical Committee Reports November 27 Revenue Requirements Workshop	The Parties agree that a schedule similar to that proposed (without the Technical Committee Reports) with a goal of achieving firm rates by December 1 for the following year. The Annual Review will focus on the results of the most recently completed fiscal year and whether the Company is entitled to an incentive payment. Part 1: Review and analysis of all material variances (+/-) pertaining to:	Exhibit B-1, Tab 3, P. 6 & Tab 9a, P. 2, Exhibit B-12, BCUC IR 83.1

	a. all relevant line items comprising the cost of service, and b. sales volumes (re revenues) for the historic period. Part 2: Review and analysis of the Company's actual performance compared to approved targets for the Performance Standards. After completion of the Annual Review, the Commission will issue an Order confirming the results of the Annual Review and the incentive payment. FortisBC is required to file detailed information with respect to Parts 1 and 2. A full round of written Information Requests as proposed in the timetable set out in response to BCUC IR 83.1 will take place prior to the Annual Review. The Revenue Requirements Workshop will focus on future test periods. The Technical Committees are abolished; hence the process step involving the filing of Technical Committee Reports is not required. After completion of the Revenue Requirements Workshop the Commission will issue an Order confirming the rates for Company for the following year.	

6. No Surprises	FortisBC is to advise all parties of any major changes planned for the Utility and nothing in this settlement provides FortisBC with any approval to change its business practices to the detriment of customers.	Exhibit B-12, BCUC IR 76.1
7. Errors Any errors in forecast and/or accounting data used in setting Revenue Requirements will be rectified before calculating the ROE variance for the sharing mechanism.	Accepted.	None

I.M.E.U.

Interior Municipal Electrical Utilities

APPENDIX C

Cities of Kelowna, Penticton, Grand Forks, District of Summerland, Nelson Hydro, Princeton Light & Power

May 8, 2006

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: William J. Grant, Transition Advisor
Regulatory Affairs & Planning

Dear Mr. Grant,

Re: FortisBC Inc. ("FortisBC") – Negotiated Settlement 2006 Revenue Requirements Application and Multi-Year Performance Based Regulation ("PBR") Mechanism

IMEU group agrees with the revised Negotiated Settlement Agreement and supporting documents as circulated by Commission staff on May 4, 2006 regarding FortisBC's 2006 Revenue Requirements and PBR Mechanism. We would also like to acknowledge the efforts of all parties and Commission staff in reaching this settlement.

If you have any questions, do not hesitate to contact us.

Yours truly,

CITY OF KELOWNA

Rod Carle, C.I.M. P.Mgr.
cc: IMEU group
Registered Intervenors

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0016

May 8, 2006

VIA ELECTRONIC MAIL

CONFIDENTIAL

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

Attention: **William J. Grant, Transition Advisor,**
Regulatory Affairs & Planning

Dear Sirs/Mesdames:

Re: FortisBC Inc. ("FortisBC") – Negotiated Settlement 2006 Revenue Requirements Application and Multi-Year Performance Based Regulation ("PBR") Mechanism

We have reviewed the Negotiated Settlement Agreement and supporting documents provided by the Commission's staff on May 4, 2006 with respect to the above-noted matter. The Commercial Energy Consumers Association of British Columbia agrees with the terms set out in the Negotiated Settlement Agreement and supporting documents.

We appreciate the significant effort that the parties and the Commission staff have put in to arrive at this settlement.

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

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

Christopher P. Weafer
CPW/jlb
cc: Fong Kwok
cc: CEC

The
British Columbia
Public Interest
Advocacy Centre
208–1090 West Pender Street
Vancouver, BC V6E 2N7
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Richard J. Gathercole 687-3006
Sarah Khan 687-4134
Patricia MacDonald 687-3017
James L. Quail 687-3034
Leigha Worth 687-3044
Barristers & Solicitors

Valerie Conrad
Articled Student

Via email

May 8, 2006

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: William J. Grant, Transition Advisor
Regulatory Affairs & Planning

Dear Mr. Grant,

Re: FortisBC Inc. ("FortisBC") – Negotiated Settlement 2006 Revenue Requirements Application and Multi-Year Performance Based Regulation ("PBR") Mechanism

BCOAPO *et al.* agrees with the revised Negotiated Settlement Agreement and supporting documents as circulated by Commission staff on May 4, 2006 regarding FortisBC's 2006 Revenue Requirements and PBR Mechanism. We would also like to acknowledge the efforts of all parties and Commission staff in reaching this settlement.

If you have any questions, do not hesitate to contact us.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

original signed by

Sarah Khan
Counsel for BCOAPO

c: BCUC, Attention: Fong Kwok
Registered Intervenors

APPENDIX C

May 8/06.

B.C.U.C

Attention:- Fong Kwok,

Re: Fortis N.S.P.

I accept the final negotiated settlement agreement.

Buryl Slack

BURYL JONAS SLACK
Intervenor

Box 356, Osoyoos, B.C. V0H 1V0
Phone 1-250-495-6702

APPENDIX C

Alan Wait
Box 2663
Grand Forks, B.C.
V0H 1H0
alwait@telus.net
250-442-8341
May 8, 2006

British Columbia Utilities Commission
Sixth Floor
900 Howe St, Box 250,
Vancouver, B.C. V6Z 2N3

Att: Fong Kwok

Re: FortisBC Negotiated Settlement for 2006 Revenue Requirements

Dear Fong:

I am still unable to support the proposed settlement agreement, specifically in regards to item #14, Depreciation Expense.

I believe that the Depreciation study must be thoroughly examined, and understood by all parties before the new depreciation rates are accepted as is, or modified, and new depreciation rates are used in the revenue requirements for 2006 and future years.

My concerns as per my letter of May 1, 2006 stand.

I have also noticed a small error in item #15 on page 9 of the settlement, where the existing DSM costs are to be amortized "over the existing 12 year period". Presently DSM charges are amortized over 8 years. Tab 5, P.72, L.8

The Depreciation expense is too big an item to simply ignore for 2 to 3 years.

Respectfully submitted,

Alan Wait

From: Richard Tarnoff [rgt@nethop.net]
Sent: Monday, May 08, 2006 12:06 PM
To: Grant, Bill J BCUC:EX

Cc: Dick Gathercole; Chong, Doug BCUC:EX; Kwok, Fong Y BCUC:EX; Nakoneshny, Philip BCUC:EX; Tomen, Rose BCUC:EX; rleslie@city.nelson.bc.ca; Brian Parent; chuck.lee@fortisbc.com; david.bennett@fortisbc.com; don.debienne@fortisbc.com; john.walker@fortisbc.com; joyce.martin@fortisbc.com; Lavern Humphrey; michael.mulcahy@fortisbc.com; Rod Carle; cweafer@owenbird.com; Al Wait; Sarah Khan
Subject: Re: FortisBC 2006 RR and PBR Mechanism

May 8, 2006

BC Utilities Commission
900 Howe Street
Vancouver, BC, V6Z 2N3

Via E-mail

Dear Sirs and Madames,

Re: FortisBC 2006 Rev. Req. and PBR Mechanism

Natural Resource Industries and Hedley Improvement District approves the final Negotiated Settlement Agreement and supporting documents for the above named hearing. We would like to thank all participants for their efforts.

Yours truly,

Richard Tarnoff

cc: participants

Attachment 26.1

Canadian Electricity Association

perspectives

Energy Efficiency

Canadian Attitudes Towards Energy Efficiency

The Canadian Electricity Association has conducted the annual Public Attitudes Survey since 1990. The survey explores the attitudes of Canadian utility customers on the importance of specific issues in relation to their electricity supplier. The survey also measures levels of satisfaction or concern with regard to responsibilities for information and initiatives related to electricity. It is a confidential report commissioned by CEA for the exclusive use of its Corporate Utility Members.

Leadership in Energy Efficiency Programming

Electric utilities have long been involved in the implementation and delivery of energy efficiency programming. Utilities understand current energy challenges and enjoy a one to one relationship with consumers. They also have relationships with building developers, trades and energy service providers and program experience. This combination of experience and established relationships means utility driven energy efficiency programs are highly effective and this is mirrored by Canadian's expectations with respect to the provision of energy efficiency information and program delivery.

Canadians Associate Energy Efficiency with their Electric Utility

The Canadian Electricity Association's 2005 Public Attitudes Survey examined public perception with respect to the role of utilities in the delivery of energy efficiency programming. Respondents from across Canada strongly associated energy efficiency programs with their electric utility affirming the vital role of utilities in delivering effective energy management programs.

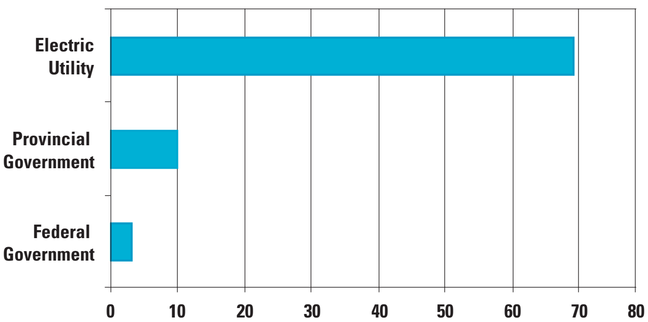
While Information about energy efficiency is important to the majority (84%) of Canadians, when asked who should be providing energy efficiency information and deliver energy efficiency programs Canadians were equally aligned in their expectation that it is the responsibility of their electric utility. Other choices considered were government (federal, provincial, municipal), private agencies and environmental or non profit groups. Fewer than 1 in 10 Canadians selected these delivery options while almost 7 in 10 named their electric utility. Although respondents displayed confidence in the ability of electric utilities to provide information and programs, only one-half of respondents were aware of any initiatives led by their electric utility company to help use electricity more efficiently.

Encouraging Energy Efficiency

The results of the CEA survey present an important opportunity to encourage energy efficiency at a time when consumers are focusing more closely on their electricity transactions and practices. Government-led programs and information could be more effectively deployed by taking full advantage of high consumer confidence in utilities as delivery agents for energy efficiency information and programs. In addition long-term sustained support and incentives for utility-led energy efficiency programming would enhance the level and scope of program availability.

Canadian Attitudes Towards Energy Efficiency

Who should provide energy efficiency info?

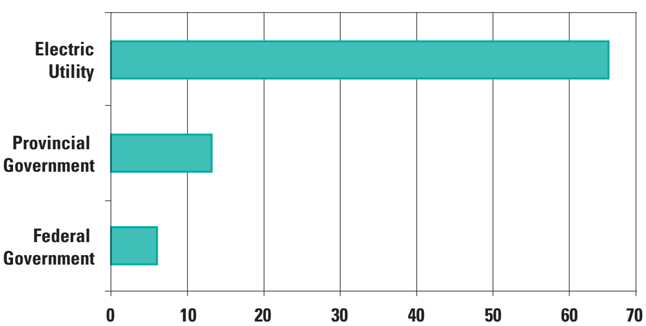


In your opinion, who should be providing you information about the efficient use of electricity?

Energy Efficiency Information Has High Value

Canadians place great importance on receiving information about using electricity more efficiently. When asked to rate the importance of receiving this information, 84% of respondents said that it was important to them and over half of the Canadians surveyed felt that it was very important.

Who should deliver energy efficiency programs?



In your opinion, who should be delivering energy efficiency programs to you?

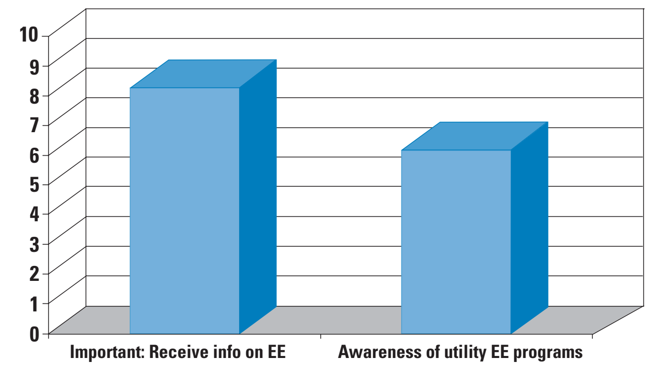
Confidence in Electric Utilities is High

Canadians are confident in electric utilities' ability to provide information and programming. It is the opinion of 64% of Canadians that their electric utility company should be providing information about the efficient use of electricity. A similar proportion of Canadians (65%) believe that electric utility companies should be responsible for delivering energy efficiency programs.

Improved Program Awareness is Needed

While 84% of Canadians believe that information about energy efficiency is important, only one half are aware (50% rate their awareness as a 7 or higher) of any initiatives led by their electric utility company to help use electricity more efficiently. Utilities are uniquely positioned to deliver on customer expectations with respect to energy efficiency; however, they cannot do it alone. Support and encouragement from government and regulators in the form of policy certainty and long-term and sustained incentives are necessary to realize Canada's energy efficiency potential.

Importance and Awareness



On a scale of one-to-ten, how important is it that you receive information on using electricity more efficiently?

On a scale of one-to-ten, how aware are you of initiatives of your electric utility company to help you use electricity more efficiently?

The CEA Customer Council

CEA's Customer Council acts as the bridge for "customer" components of the electricity business and represents member utilities' interests in this area of business operations to the industry and to government. Collectively, Customer Council members provide electricity service to almost 6 million Canadian customers. Energy efficiency programs are an important part of meeting customer service expectations and this is reflected in the initiatives and opportunities supported by the Customer Council.

For more information on CEA's Customer Council, please contact Ann Kelly at (613) 692-0102 or kelly@canelect.ca

Perspectives is published by the Canadian Electricity Association,
the voice of Canadian Electricity.
For more information: info@canelect.ca, (613) 230-9263

Canadian Electricity Association
Association canadienne de l'électricité
www.canelect.ca

Attachment 34.1

Northwest Power and Conservation Council

MARGINAL CARBON DIOXIDE PRODUCTION RATES OF THE NORTHWEST POWER SYSTEM

JUNE 13, 2008

851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204-1348
www.nwcouncil.org

Steve Crow
Executive Director

503-222-5161
800-452-5161
Fax: 503-820-2370

Marginal Carbon Dioxide Production Rates of the Northwest Power System

SUMMARY

The cost of future carbon dioxide (CO_2) regulation is a significant factor in utility resource planning in the Pacific Northwest. Failure to properly account for this risk when evaluating resources can result in poor resource decisions and higher costs for the region's ratepayers.

One of the benefits of conservation is that it avoids CO_2 emissions.[1] The benefit it provides depends on what generating resources would be replaced and how much CO_2 they produce. This requires understanding what generating resources are on the margin; that is, the generation that could be displaced by the conservation. The marginal resource is the last resource brought on-line to supply power during a given time period (i.e., the highest variable cost resource available and needed during the period). In the Northwest, the average marginal CO_2 production is substantially higher than the average CO_2 production from all electricity generation. This is because hydroelectricity and wind, which have low operating costs and no CO_2 emissions are brought on-line before coal-fired or natural gas-fired generating units. Because only the marginal plants would be displaced by conservation, it would not be proper to use the average of CO_2 emissions from all power generation to estimate the CO_2 saved through conservation.

This paper evaluates what resources are on the margin in every hour and what the CO_2 reduction would be as a result of conservation. The analysis is an extension of the Council's recent interim wholesale power market price forecasts.[2] In the base case for that analysis, natural gas-fired combined-cycle plants are on the margin most of the time so conservation would avoid the CO_2 emission of a gas-fired combined-cycle power plant for most of the hours in a year. When the marginal CO_2 emissions for each hour are averaged over all of the hours in a year, the average of these hourly CO_2 emissions is about 0.8 pounds per kilowatt-hour. This increases the value of conservation by up to $5.60 per megawatt-hour (in constant 2006 dollars) under the base case CO_2 price assumption of $14 per ton in 2025.

The value of conservation can be significantly higher for measures, such as city street-lighting programs, that target load reduction during weekend nighttime hours. This is because coal-fired generation is typically the region's marginal resource during these low load hours. Since coal-fired generation has higher CO_2 emissions than natural gas combined-cycle plants, more CO_2 is displaced by each unit of conservation.

In addition to the Interim Base Case, this analysis tests two alternative assumptions about future resource costs. First it looks at a case of higher capital costs for generating resources, similar to recent experience. This case produced no change in the resources that were expected to be developed in the Northwest, but it did eliminate significant coal development in other parts of the West. Fewer coal resources reduce Westwide annual CO_2 production. Interestingly, the annual

---

[1] Similarly, the value of other low-CO_2 resources including many types of demand response and most renewable resources should include the value of the CO_2 production displaced by the resource.
[2] The "Interim Wholesale Power Price Forecast" paper is available at: http://www.nwcouncil.org/library/2008/2008-05.pdf

CO_2 emissions in the Northwest increase since Northwest resources run more frequently to meet regional and Western loads. This is because fewer new resources are constructed in this high capital cost case. The increased use of Northwest resources means that coal-fired generation is used less often as the region's marginal resource. So, even though the region's annual CO_2 emissions increase, its marginal CO_2 production rate decreases to about 0.7 pounds of CO_2 per kilowatt-hour.

The second case adds higher CO_2 allowance prices (the possible future costs of CO_2 emissions) of $43 per ton of CO_2 beginning in 2012 to the high capital cost case. This results in much higher average marginal CO_2 emissions, up to 1.8 pounds per kilowatt-hour, and raises the value of conservation to as high as $38.00 per megawatt-hour. The high CO_2 prices increase the operating cost of coal plants more than they increase the operating cost of natural gas combined-cycle plants. This differential is enough to cause natural gas plants to be dispatched before coal-fired plants. With natural gas plants now operating first, coal plants are forced to the margin. This increases the region's average marginal CO_2 production rate and, therefore, the value of conservation to lower CO_2 emissions.

The other side of this change is that with higher CO_2 prices, natural gas-fired plants provide more baseload generation and therefore reduce the use of coal-fired generation as a share of total electricity production. As a result, total CO_2 emissions in this case are greatly reduced. Whereas, total CO_2 emissions in the region continued to grow in the Interim Base Case and the High Capital Cost Case, total CO_2 emissions are reduced to near or below 1990 levels in the High CO_2 Price Case. This is a direct result of the reduction in generation from existing coal-fired plants.

The effectiveness of the higher CO_2 prices in reducing CO_2 emissions appears to be very sensitive to fuel costs. At $43 per ton of CO_2, the variable cost of most existing coal plants is slightly higher than the variable cost of gas combined-cycle plants. However, any increase in the cost of natural gas would favor the dispatch of coal and return combined-cycle plants to the margin. A higher CO_2 price would be needed to restore coal to the margin. The Council intends to further explore this issue during development of the Sixth Power Plan.

Marginal Carbon Dioxide Production Rates of the Northwest Power System

INTRODUCTION

During any given hour of the year, there are numerous generating units supplying power to the Pacific Northwest power system. Some of these units will be hydroelectric units or wind generating units that do not emit CO_2 into the atmosphere. At the same time, some of these units will likely be coal-fired or natural gas-fired generating units that do emit CO_2 into the atmosphere. Each type of generating unit has a distinct rate at which it emits CO2. For example, a contemporary natural gas-fired combined cycle unit emits roughly 0.8 pounds (lbs.) of CO_2 per kilowatt-hour. A typical conventional coal-fired steam unit emits roughly 2.3 lbs. of CO_2 per kilowatt-hour.

One way to measure the CO_2 production rate of the Northwest Power system is to average the rates of all the generating units operating during a given time period. In this paper, we use the term, *average CO_2 production rate*, to refer to an average across *all resources* operating during a given time period.

Another way to measure the CO_2 production rate of a power system is to determine the CO_2 emissions rate of the last resource (or marginal resource) brought on-line to supply power during a given time period. In wholesale power markets, generating resources are typically brought on-line in the order of their operating costs. In other words, resources with low operating costs are used before resources with higher costs. In general, hydroelectric, nuclear and wind generating units will be brought on-line before coal-fired or natural gas-fired generating units. It is the CO_2 emissions of the marginal resource that can be avoided by adding energy-efficiency measures to the system.

This paper estimates the Pacific Northwest power system's marginal resource, and its CO_2 production rate, during each hour for four separate years: 2010, 2015, 2020, and 2025. Because there are typically 8,760 hours during a year, we summarize our results by providing *average marginal CO_2 production rates* for each year. In this paper, we use the term *average marginal CO_2 production rate* to refer to an average across *only the marginal resources* operating during a given time period.

The major findings and conclusions of this new analysis are:

- For the Northwest power system, with its large amount of hydroelectric, nuclear and wind generating resources, the *marginal CO_2 production rate* is considerably higher than the *average CO_2 production rate*. Power system planners and resource analysts should use the marginal CO_2 production rate to quantify and evaluate the ability of energy-efficiency and other resources with low CO_2 emissions to reduce emissions.

- Marginal CO_2 production rates for the Northwest power system, under our Interim Base Case assumptions, are forecast to range between 0.7 lbs. of CO_2 per kilowatt-hour (kWh) and 0.9 lbs. of CO_2 per kWh over the period 2010 through 2025.

- The region's average marginal rate of CO_2 production and its overall level of CO_2 production tend to move together, but in opposite directions. For example, under our combined High Capital Cost and High CO_2 Price Case assumptions, the region's marginal CO_2 production rate is forecast to jump as high as 1.8 lbs. of CO_2 per kWh. Carbon regulation, while decreasing overall CO_2 emissions, also increases the region's marginal CO_2 production rate since coal plants become the marginal resource.

- The type and amount of generating resources added to the Western power system outside our region influence the Pacific Northwest's CO_2 production. For example, although the Interim Base Case and the High Capital Cost Case forecasts have essentially the same resource mix for the Pacific Northwest, the High Capital Cost Case forecasts less overall new plant development, and no new conventional coal-fired plant development, in the Western power system over the planning period. This results in lower annual CO_2 emissions for the Western power system. At the same time, however, annual CO_2 production increases in the Pacific Northwest (and marginal CO_2 production rates decline) as Northwest resources are operated more intensely to meet loads both inside and outside the region.

METHODOLOGY

The methodology we use to estimate the Pacific Northwest power system's marginal resource is an extension of the modeling described in the Council's recent Interim Wholesale Power Price Forecast paper.[3] In this paper, we provide further analysis of two scenarios presented in the interim forecast paper: the Interim Base Case and the High Capital Cost Case. Each of these cases incorporates the same fuel price forecasts, estimates of the future costs of CO_2 allowance prices, and schedule of renewable resource additions to achieve state renewable portfolio standards. The only difference between these cases is the estimated costs of constructing new generating resources.[4] The Interim Base Case assumes construction costs from the "2006 Biennial Monitoring Report of the Fifth Power Plan." Since the release of the monitoring report, construction costs have increased significantly. The High Capital Cost Case was developed to better reflect current estimates of the future cost of building new generating resources and is being used in the preliminary studies for the Sixth Power Plan. We also present new results for a combined High Capital Cost/High CO_2 Price Case. The resource mix underlying each of these forecasts affects the choice of the marginal resource, and therefore, the marginal CO_2 production rate for the Pacific Northwest power system. These effects are discussed in the results section of this paper.

Council staff uses the AURORA$^{xmp®}$ Electric Market Model to develop its wholesale power price forecasts.[5] This model simulates hourly supply and demand to determine a marginal resource and market-clearing price for every hour of the simulation period for each of the load-resource zones in the model. The Council's configuration of AURORA^{xmp} uses 18 load-resource zones to represent the Western power system. The Pacific Northwest power system is

---

[3] The "Interim Wholesale Power Price Forecast" paper is available at: http://www.nwcouncil.org/library/2008/2008-05.pdf

[4] For a description of our current estimates of new resource capital costs see the "Interim Wholesale Power Price Forecast" paper (pp. 10-13).

[5] Available from EPIS, Inc. (www.epis.com).

represented by 6 of these zones.[6] Therefore, for each hour of a simulation period, AURORA^{xmp} identifies 6 marginal resources for the Pacific Northwest, one for each zone.[7]

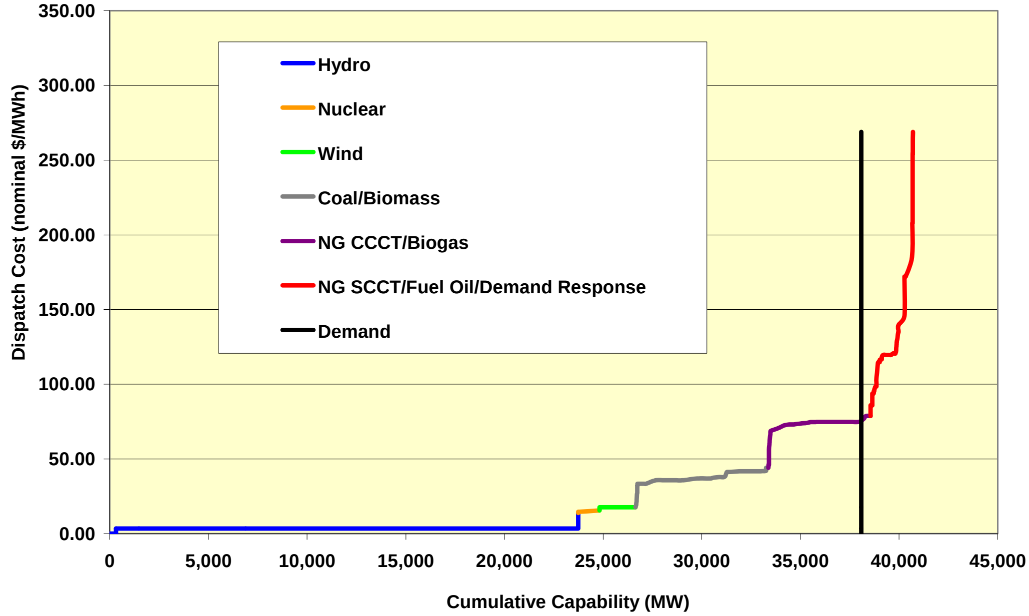
In order to identify a single Pacific Northwest marginal resource, and marginal CO_2 production rate, for each hour of the simulation period, Council staff conducted additional analysis on the AURORA^{xmp} hourly output databases. The hourly output databases contain statistics summarizing the simulated operation of each generating unit located in the Pacific Northwest.[8] Staff performed a series of filtering steps to arrive at a single marginal resource for each hour. First, staff removed any units considered to be must-run resources. Must-run resources are those that are operated regardless of wholesale power market prices. For the Northwest, must-run resources include: wind plants, municipal solid waste facilities, industrial co-generation facilities, geothermal steam plants, and landfill gas energy recovery and other biogas facilities. Second, for each hour, any unit that did not generate electricity was removed from consideration. Finally, of the remaining units, the unit with the highest dispatch cost was selected as the region's marginal resource for each hour.[9] This process resulted in a single marginal resource for the Pacific Northwest for each hour of the simulation period.[10]

This methodology for identifying the region's marginal resource is analogous to the resource stacking approach depicted in Figure 1. The figure is a snapshot of our forecast of the region's supply and demand during the peak hour of demand in 2020.[11] The vertical axis of the figure is dispatch cost--the cost that can be avoided by curtailing operation of a resource. For any resource, the dispatch cost comprises the variable operating and maintenance costs (including integration costs for intermittent resources), variable fuel cost, CO_2 allowance cost, any unit cycling premium, and a dispatch premium representing the "profit" over cost demanded by a plant owner to dispatch the resource.

The horizontal axis represents cumulative generating capability for the hour. The supply curve for this hour starts with the region's lowest-cost resource, hydroelectric generation, and adds supply in order of increasing dispatch cost. The forecast demand for electricity in this hour is 38,081 megawatts, shown as the vertical black line. The region's marginal resource for this hour is the generating unit that is situated at the intersection of the region's supply and demand curves.

[6] The Pacific Northwest zones are identified as PNW Westside North, PNW Westside South, PNW Eastside North, PNW Eastside South, Idaho South, and Montana East.
[7] This is equivalent to 52,560 marginal resources in the Pacific Northwest on an annual basis (8,760 hours * 6 load-resource zones = 52,560 marginal resources).
[8] The annual databases contain roughly 7.4 million records (844 generating units * 8,760 hours = 7.4 million records)
[9] If two or more units tied for the highest dispatch cost in an hour, the unit operating farthest from its maximum capability (or closest to its minimum capacity) was chosen as the marginal resource.
[10] For an annual simulation period, this results 8,760 marginal resources in the Pacific Northwest.
[11] The snapshot shown is for hour ending 7:00 P.M. on January 15, 2020.

Figure 1: Illustration of the marginal resource selection methodology (High Capital Cost Case)



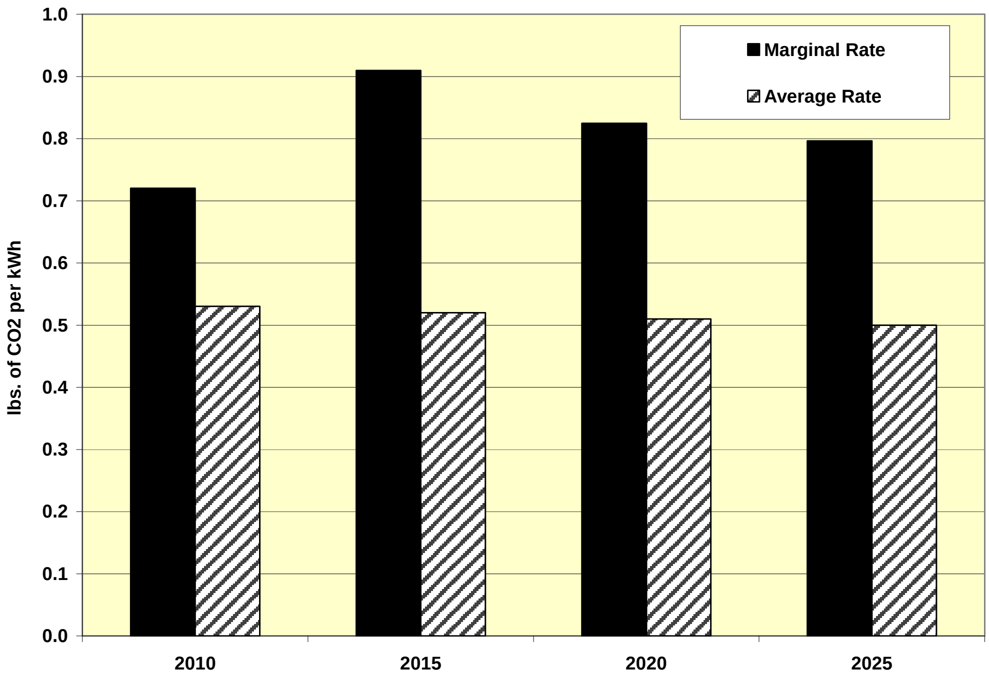
The region's marginal resource will change not only from season to season as the region's water supply, loads, fuel prices, and resource availability varies, but also from hour to hour as demand changes. The filtering methodology described in the previous paragraph is roughly analogous to performing this resources stacking for each hour of the forecast year.

RESULTS

Interim Base Case

For the Northwest power system, with its large amount of hydroelectric, nuclear and wind generating resources, the *marginal CO_2 production rate* is considerably higher than the *average CO_2 production rate*. Figure 2 compares these two rates for the Interim Base Case.

Figure 2: Northwest marginal and average CO_2 production rates (Interim Base Case)



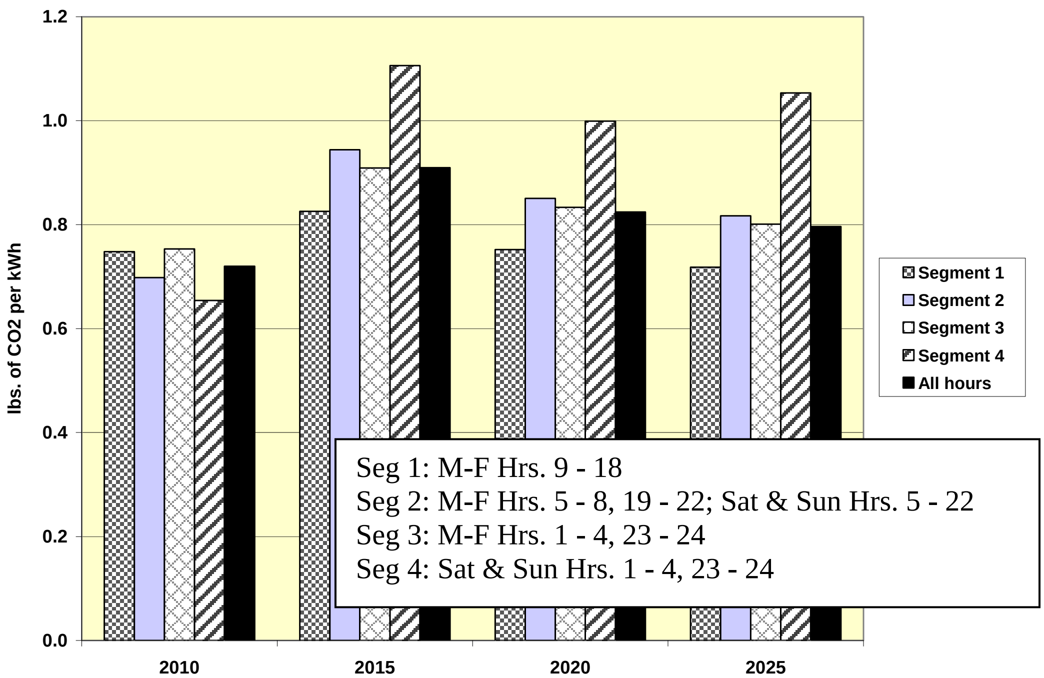
Power system planners and resource analysts should use the marginal CO_2 production rates to evaluate the CO_2 cost associated with future purchases of power from the wholesale power market and the relative benefits of energy-efficiency measures and other resources with lower CO_2 emissions. For example, given the Council's current interim forecast of future CO_2 emissions prices (i.e., \$11.12 per ton in 2015, \$12.55 per ton in 2020, and \$14.15 per ton in 2025), the estimated CO_2 cost included in future purchases from the wholesale power market would be \$5.06 per megawatt-hour (MWh) in 2015, \$5.17 per MWh in 2020, and \$5.63 per MWh in 2025.[12]

Marginal CO_2 emission rates (pounds of CO_2 per kWh) vary by time of day and day of week because the marginal generating resource changes with load. Gas-fired power plants with relatively high variable costs are typically on the margin during heavier load hours, whereas coal-fired plants with lower variable costs can be on the margin during nighttime and weekend light load hours. Therefore, both the physical quantity, and dollar value, of avoided CO_2 emissions vary with time. The Council and the Regional Technical Forum use four load

[12] The calculation of the market CO_2 cost in 2015 is: (0.9 lbs. of CO_2 per kWh) / (2000 lbs. per ton) * (1000 kWh per MWh) * (\$11.12 per ton of CO_2).

segments to assess the cost-effectiveness of conservation measures. Figure 3 shows the average marginal CO_2 emission rates for the four segments for the four future years.

Figure 3: Northwest marginal CO_2 production rates by load segment (Interim Base Case)

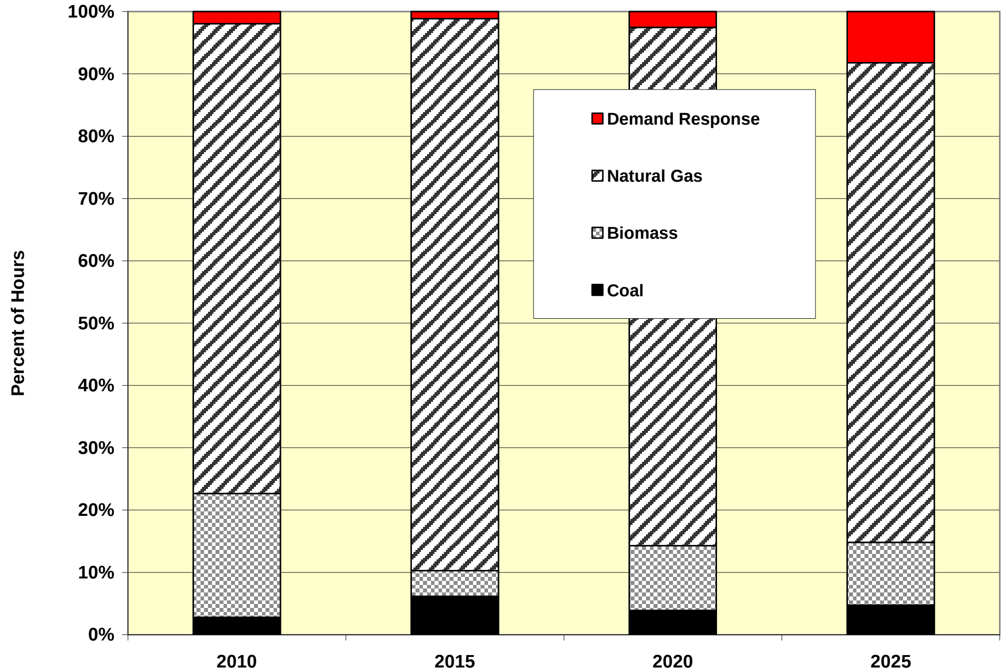


The pronounced increase in the marginal CO_2 production rate during weekend nighttime hours (i.e., during Segment 4 hours) is due to coal-fired units being the marginal resource during these low-load hours. This is consistent with the recent and expected addition of significant amounts of wind generation to the Northwest power system, which pushes coal-fired resources up toward the margin.[13] After 2015, there is a slight downward trend in the Northwest's marginal CO_2 production rates. This downward trend reflects the changing fuel mix of the region's marginal resources over time.

Figure 4 shows the percentage of hours in each year that resources of various fuel types are on the margin. The percentage of hours that coal-fired resources are the marginal resource declines from 6.2 percent in 2015 to 4.7 percent in 2025. As regional loads continue to grow, there is also an increase in the number of high load hours during which demand response is the region's marginal resource. Both of these changes have the effect of lowering the region's marginal CO_2 production rates.

[13] An open issue at this time is whether the coal-fired resources operating at the margin during these light load hours can provide the operational flexibility needed to integrate intermittent resources into the power system.

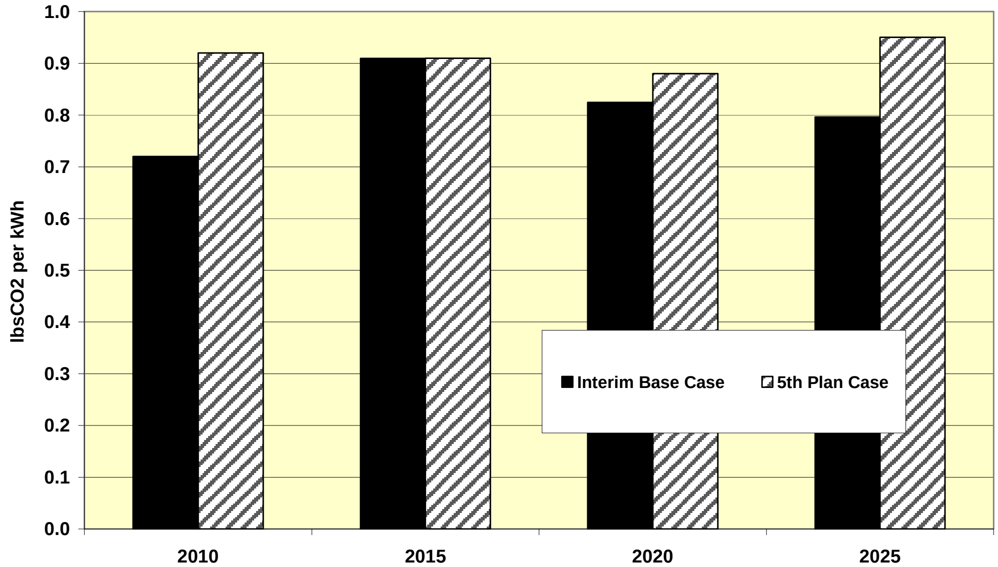
Figure 4: Percentage of hours resources of various fuel types are the marginal resource (Interim Base Case)



The low percentage of hours that coal-fired resources are the region's marginal resource is a significant change from the Council's previous forecast of the marginal rate of CO_2 production in April, 2006.[14] At that time, coal-fired resources were forecast to be the marginal resource in 16 percent of the hours in 2010, declining to 12 percent of the hours in 2025. This difference in marginal resource mix is evident in a comparison of the two forecasts of marginal CO_2 production rates (see Figure 5).

[14] Staff presented, "Power System Marginal CO_2 Production Factors" to the Council's Power Committee on April 11, 2006, in Whitefish, Montana.

Figure 5: Comparison of marginal CO_2 production rates (Interim Base Case vs. 5th Plan Case)



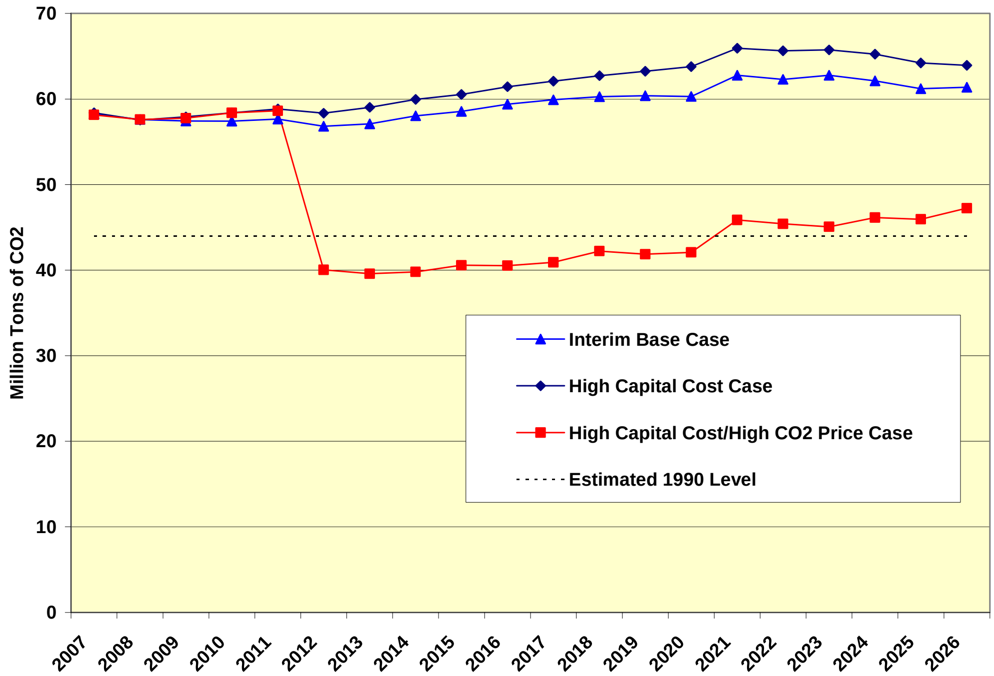
The decrease in coal-fired generation on the margin can be partly attributed to the improved methodology for selecting the region's marginal resource.[15] However, this difference is also partly explained by differences in forecast assumptions and the forecast, or recommended, resource mix for the Pacific Northwest. For example, the Interim Base Case uses higher CO_2 allowance prices than the 5th Plan Case.

It is important to place the declining trend in the Northwest power system's marginal CO_2 production rates, and the underlying changes in its marginal resource mix, within the wider context of the overall power system CO_2 production. In the Interim Base Case, Northwest power system CO_2 emissions are forecast to total 57 million tons in 2010, and to increase to 61 million tons in 2025. For comparison, we previously estimated that the Northwest power system's CO_2 production was 44 million tons in 1990 and that it would have been 57 million tons in 2005 (had normal hydro conditions prevailed).[16] Figure 6 shows our CO_2 emissions forecasts for the Northwest power system under the three future scenarios discussed in this paper.

[15] The previous methodology selected a single regional marginal resource during each hour of the year by starting with the units that AURORAxmp identified as the marginal resource in each of the six Northwest load-resource zones. Starting with only one resource in a load-resource zone, and then removing it from further consideration if it is a must-run resource, has the effect of removing all the resources in that zone from consideration as the region's marginal resource. In some hours, this method could erroneously select an intra-marginal resource as the region's marginal resource. The prior method had the potential to overstate the occurrence of coal-fired units and hydroelectric units as the region's marginal resource. The methodology presented in this paper avoids this problem by starting with all of the generating units dedicated to serving loads in the Pacific Northwest.

[16] We also estimated that with implementation of the recommended resource portfolio of the 5th Power Plan, CO_2 emissions would total 67 million tons in 2024. These estimates are from the Council's paper titled, "Carbon Dioxide Footprint of the Northwest Power System." This paper is available at: http://www.nwcouncil.org/library/2007/2007-15.htm

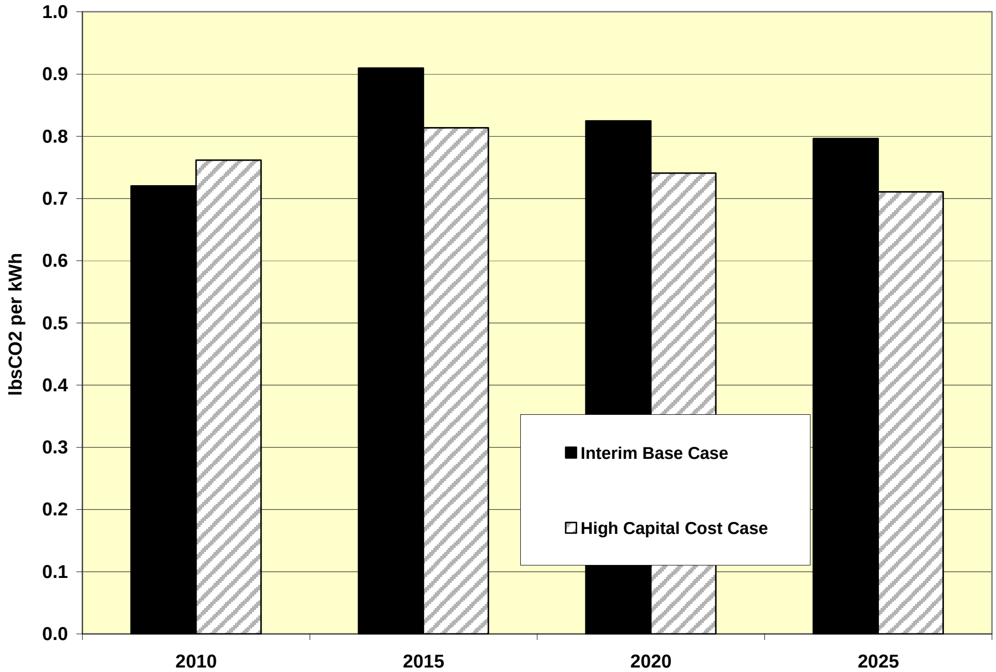
Figure 6: Forecasts of the Northwest power system's CO_2 emissions



High Capital Cost Case

It is also important to describe the sensitivity of our results to changes in key input assumptions. Figure 7 shows the effect of our revised forecast construction costs for new generating resources on marginal CO_2 production rates. The higher construction costs in the High Capital Cost case reduce the level of forecast resource additions in other regions of the West. This leads to more intense use of power resources in the Pacific Northwest, and to lower marginal CO_2 production rates.

Figure 7: Comparison of marginal CO_2 production rates (High Capital Cost Case and Interim Base Case)



The portfolio of Northwest generating resources is essentially the same in both the High Capital Cost Case and Interim Base Case. In both cases, Northwest generating resources consist of existing resources and the forecast addition of renewable resources to meet state renewable portfolio standards. The reduction in marginal CO_2 production in the Northwest is primarily driven by a change in the amount and type of new resources added to meet load in areas outside of the Northwest. The High Capital Cost Case results in more new natural gas-fired resources and fewer new coal-fired resources being added to the Western power system over the planning period.[17] This change in incremental resource mix results in Northwest resources being dispatched more often to serve loads, both inside and outside the region. This increase in the dispatch of regional resources increases the occurrence of natural gas-fired resources on the margin and reduces the Northwest's marginal CO_2 production rates.

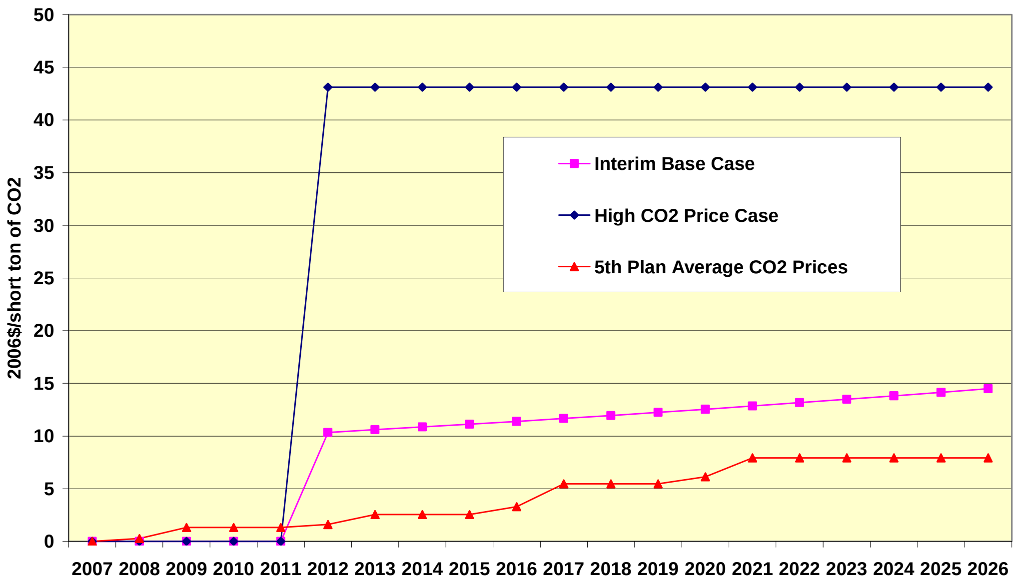
The increased utilization of the Northwest's resources also leads to higher total CO_2 production in the Northwest (see Figure 6). For example, total Northwest CO_2 production is 64 million tons in 2025 in the High Capital Cost Case compared to 61 million tons in 2025 in the Interim Base Case. However, from the perspective of the interconnected-West, the higher resource use in the Northwest contributes to the reduction in total Western CO_2 production to 461 million tons in 2025 in the High Capital Cost Case from 519 million tons in the Interim Base Case.[18]

[17] See "Interim Wholesale Power Price Forecast" paper, p. 26, for a detail description of this change in incremental resource mix.
[18] See "Interim Wholesale Power Price Forecast" paper, p. 24, for a detail description of annual Western Electricity Coordinating Council (WECC) CO_2 production.

Combined High Capital Cost and High CO_2 Price Case

The following figure shows the difference between the CO_2 allowance prices used in the Interim Base Case (and High Capital Cost Case), and the higher CO_2 allowance prices used in the High Capital Cost/High CO_2 Price case.[19] It also shows the average of the 750 possible future trajectories of CO_2 emissions prices used in the Fifth Power Plan.

Figure 8: Base and high CO_2 emission prices

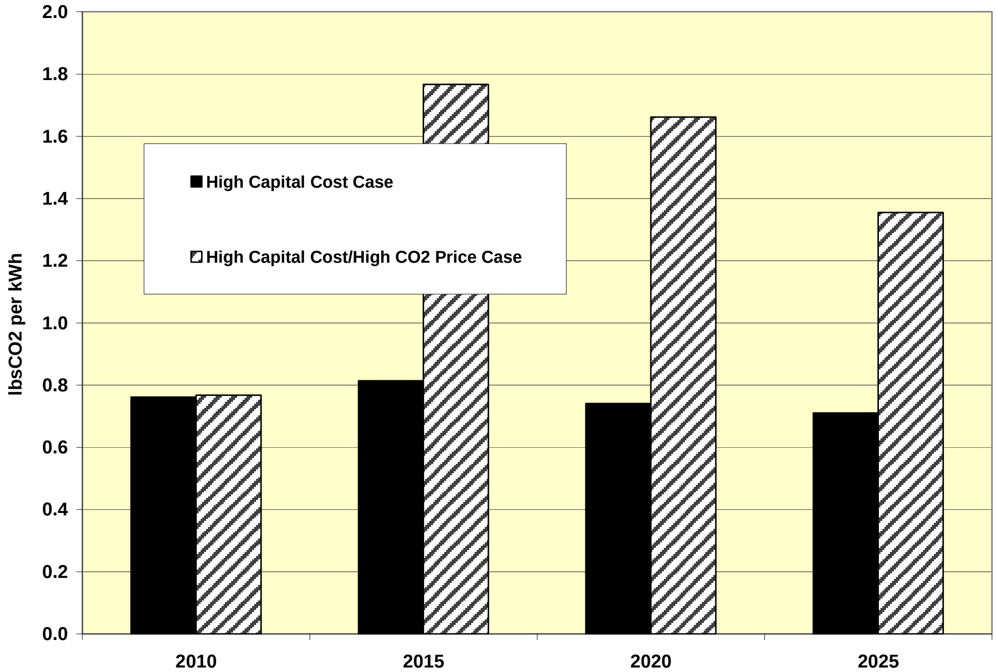


The higher CO_2 emissions prices used in the High Capital Cost/High CO_2 Price Case significantly reduce the forecast annual CO_2 production of the Western power system. Forecast Westwide CO_2 production drops from 461 million tons in the High Capital Cost Case to 384 million tons in the High Capital Cost/High CO_2 Price Case. The higher CO_2 emissions prices also drive a dramatic decline in the forecast of annual CO_2 production from the Northwest power system (see Figure 6).[20]

The higher CO_2 prices also have a significant effect on the forecast of the Northwest's marginal CO_2 production rates. These marginal rates are dramatically higher (see Figure 8). This increase occurs because the higher CO_2 prices drive heavy CO_2 producing resources to the less frequently dispatched end of the region's supply curve and puts them on the margin during more hours of the year.

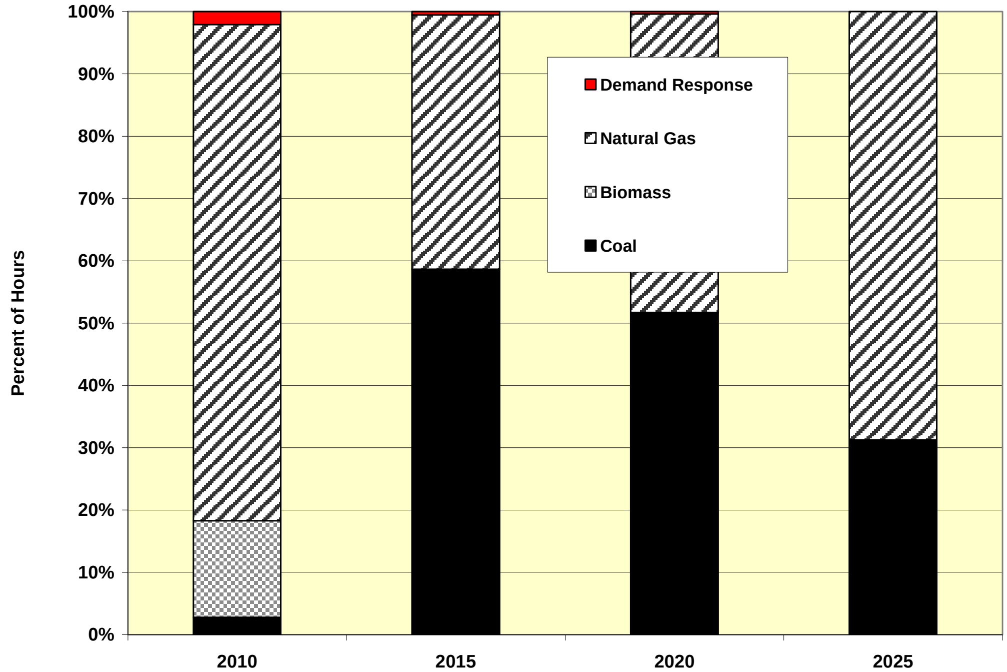
[19] For a description of the rationale underlying our CO_2 emission price assumptions see the "Interim Wholesale Power Price Forecast" paper (pp. 8-10).
[20] The higher CO_2 emissions prices result in 1,200 megawatts (MW) of new wind resources being added to the Northwest power system over the planning period (i.e., 500 MW in 2016, 200 MW in 2024, and 500 MW in 2025). This is installed wind capacity above the amount forecast to be added to meet state renewable portfolio standards.

Figure 8: Comparison of marginal CO_2 production rates (High Capital Cost Case vs. High Capital Cost/High CO_2 Price Case)



Under the High Capital Cost/High CO_2 Price Case assumptions, coal-fired resources are the marginal resource during 59 percent of the hours in 2010, 52 percent of the hours in 2015, and 31 percent of the hours during 2025. Figure 9 shows the increased role of coal as a marginal resource mix for this sensitivity case, compared to the base case shown in Figure 4.

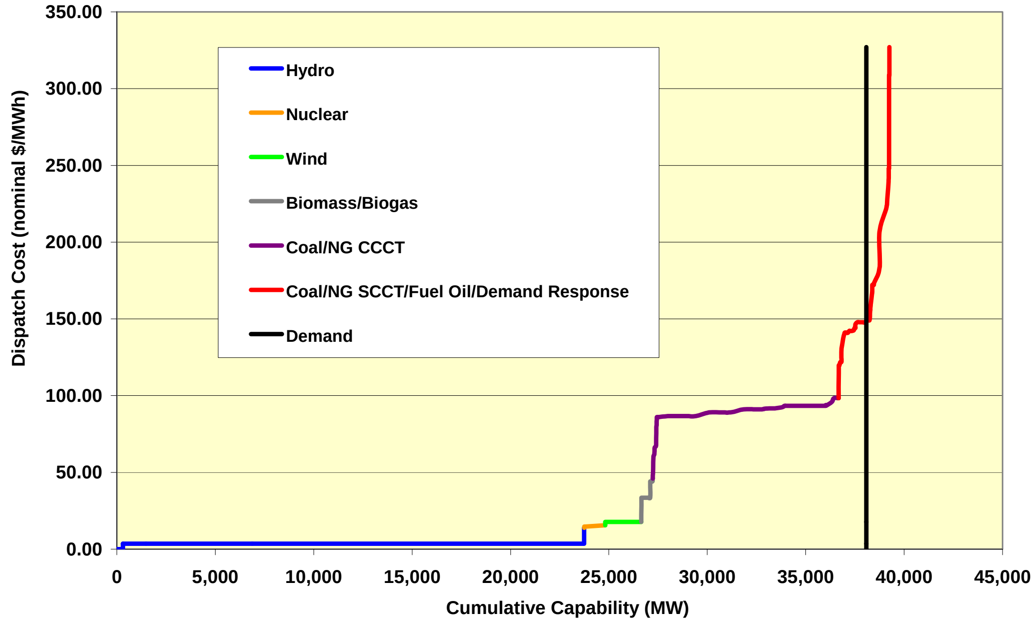
Figure 9: Percentage of hours resources of various fuel types are the marginal resource (High Capital Cost/High CO_2 Price Case)



Again, stated differently, the increase in the percentage of hours that the Northwest's coal-fired resources are on the margin is due to their higher dispatch cost because of emission charges. Their dispatch cost increases to, and in some cases surpasses, the dispatch cost of the Northwest's natural gas-fired combined cycle units. This "leveling" effect of the higher CO_2 emission prices is illustrated in the following snapshot of the region's supply and demand during the peak hour of demand in 2020.[21]

[21] The snapshot shown is for hour ending 7:00 P.M. on January 15, 2020.

Figure 10: Illustration of the change in the regional supply curve (High Capital Cost/High CO_2 Price Case)[22]



With high CO_2 emissions prices, most of the region's coal-fired units move up to share the same relative position on the region's supply curve with natural gas-fired combined cycle units (some of the less efficient coal-fired units move beyond this level to mix with natural gas-fired simple cycle units and other "peaking" resources). This leveling of the costs of coal-fired generation and natural gas-fired generation creates a "high plateau" in the region's supply curve near $90 per MWh. A quick comparison of Figure 10 and Figure 1 also highlights this effect. The resources lying along this plateau would likely clear the market during many hours of the year.

This analysis confirms that high CO_2 emission prices can drive significant reductions in total CO_2 emissions, both Westwide and in the Pacific Northwest. The analysis also shows that high CO_2 emissions prices increase the region's marginal rate of CO_2 production, and therefore, likely increase the value of energy-efficiency measures that reduce CO_2 emissions.

CONCLUSION

This paper forecasts the marginal CO_2 production rates for the Pacific Northwest power system to be between 0.7 lbs. per kilowatt-hour and 0.9 lbs. per kilowatt-hour for the period 2010 through 2025, under interim base case assumptions. The Council and the Regional Technical Forum can use these marginal CO_2 production rates to quantify the value of CO_2 emissions avoided by conservation and to evaluate the cost-effectiveness of energy-efficiency measures and other resources with lower CO_2 emission rates. These marginal CO_2 production rates are

[22] Coal purposefully appears in two places on the legend. With high CO_2 emissions prices most of the Northwest's coal units have dispatch costs similar to natural gas-fired combined cycle combustion turbines (NG CCCT), however, some of the less efficient coal units have even higher dispatch costs, similar to natural gas-fired simple cycle combustion turbines (NG SCCT) and other peaking resources.

very sensitive to changes in the future regulation, and cost, of CO_2 emissions. Because of this sensitivity, the marginal CO_2 production rates may change significantly if the assumptions regarding CO_2 allowance prices change during development of the Sixth Power Plan.

The effectiveness of the higher CO_2 prices in reducing CO_2 emissions also appears to be very sensitive to fuel costs. At $43 per ton of CO_2, the variable cost of most existing coal plants is slightly higher than the variable cost of gas combined-cycle plants. However, any increase in the cost of natural gas would favor the dispatch of coal and return combined-cycle plants to the margin. A higher CO_2 price would be needed to restore coal to the margin. The Council intends to further explore this issue during development of the Sixth Power Plan.

Sensitivity to Higher Natural Gas Price Assumptions

Addendum to Marginal Carbon Dioxide Production Rates of the Northwest Power System

SUMMARY

An important result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," indicated that with carbon dioxide (CO_2) allowance prices of $43 per ton the Northwest power system's annual CO_2 emissions could be reduced to its1990 level. This result was achieved at the Council's medium fuel price forecast.

Results presented in this addendum indicate that:

- With the Council's high fuel price forecast the $43 per ton CO_2 allowance price assumption fails to produce the same dramatic reduction in annual CO_2 emissions that were shown for the medium fuel price forecast.

- With the Council's high fuel price forecast CO_2 allowance prices would need to increase to nearly $70 per ton in order to achieve annual reductions in CO_2 emissions similar to those achieved under the medium fuel price forecast.

INTRODUCTION

An important modeling result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," is that the Northwest power system's annual carbon dioxide (CO_2) emissions can be driven below its 1990 level with CO_2 allowance prices of $43 per ton of CO_2 (in constant 2006 dollars). This CO_2 allowance cost would bring about a significant reduction in annual emissions by changing the dispatch order of coal-fired and natural gas-fired generating units. Coal-fired units would become more costly to operate than natural gas-fired units and would dispatch to meet load less often. The reduced operation of coal-fired units would lower the Northwest power system's annual CO_2 emissions.

The result presented in the marginal CO_2 assessment was achieved at the Council's medium fuel price forecast. Higher natural gas prices would be expected to increase the CO_2 allowance prices required to change the dispatch order of coal-fired and natural gas-fired plants. This addendum examines how higher fuel prices might affect this result. How sensitive is the modeled reduction in annual CO_2 emissions to increased natural gas prices? With high fuel prices how high would CO_2 allowance prices need to climb in order to reduce the Northwest power system's annual CO_2 emission to its 1990 level?

METHODOLOGY

The High Capital Cost/High CO_2 Price Case presented in the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper serves as the reference case for the analysis presented in this addendum. This case serves as the point of reference because it showed that with CO_2 allowance prices of $43 per ton the region's annual total CO_2 emissions could be reduced to its 1990 level. For ease of reference, we refer to this case as the Medium Fuel/$43 CO_2 Price Case in this addendum.

In this addendum, we also model three high fuel price sensitivity cases. This modeling is an extension of the modeling presented in the Council's recent "Interim Wholesale Power Price Forecast" paper.[23]

The first sensitivity case is a combined high fuel price and $43 per ton CO_2 allowance price case (referred to as the High Fuel/$43 CO_2 Price Case). This case is designed to test the sensitivity of the modeled reduction in the Northwest power system's annual total CO_2 emissions to high fuel prices.

The second sensitivity case is a combined high fuel price and $70 per ton CO_2 allowance price case. This is an intermediate case. The only difference between this case and the first sensitivity case is that the CO_2 allowances prices are increased to $70 per ton (in 2006 dollars). Importantly, the forecast resource mix of the Western power system is held constant in this sensitivity case. The $70 per ton CO_2 allowance price was determined to be the level needed to drive the forecast of the Northwest power system's annual CO_2 emissions below its 1990 level. We refer to this case as the High Fuel/$70 CO_2 Price/Fixed Mix Case.

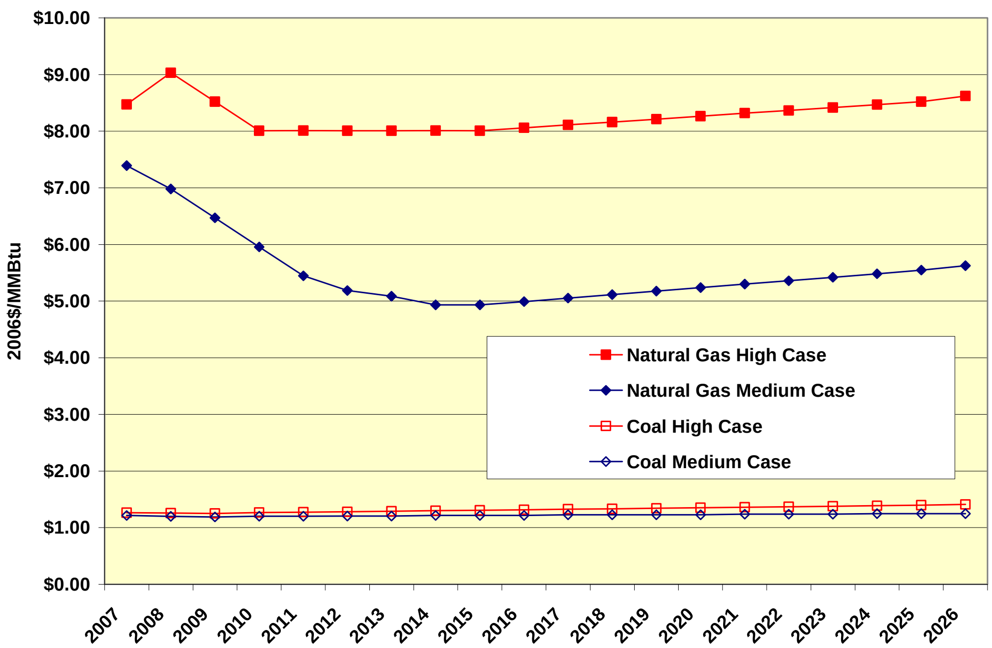
The third sensitivity case expands on the second sensitivity case by using the AURORA^{xmp} model to forecast a new incremental resource expansion for the Western power system under the $70 per ton CO_2 allowance price assumption. In other words, the underlying resource mix is allowed to change in response to the increased forecast of CO_2 emissions costs. We refer to this case as the High Fuel/$70 CO_2 Price/New Mix Case.

The Council's current set of fuel price forecasts were developed in the summer of 2007.[24] The low, medium-low, medium, medium-high, and high fuel price forecasts cover a wide range of possible future price trends. Figure 1 compares the medium and high price forecasts for natural gas and coal delivered to electricity generators located in the western load-resource zones of the Pacific Northwest. For natural gas, the high price forecast is approximately $3 per million British thermal units (MMBtu) higher than the medium price forecast over most of the planning period.

[23] The "Interim Wholesale Power Price Forecast" paper available at: http://www.nwcouncil.org/library/2008/2008-05.htm

[24] The "Revised Fuel Price Forecasts" paper is available at: http://www.nwcouncil.org/library/2007/2007-14.htm

Figure 1: Comparison of medium and high fuel price forecasts



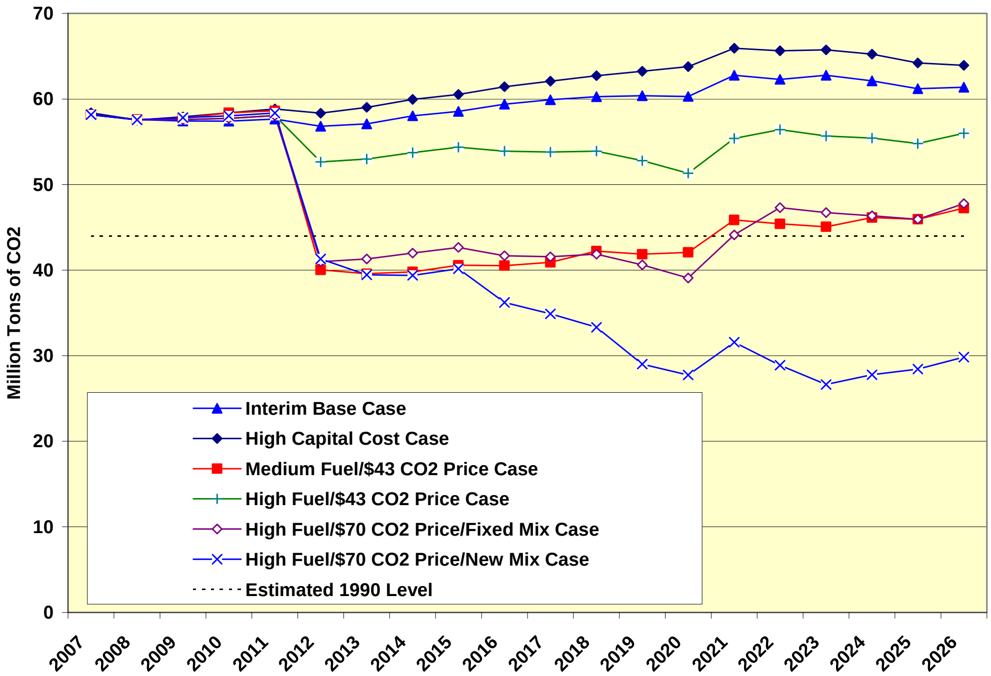
RESULTS

Figure 2 shows the Northwest power system's annual total CO_2 emissions for the reference case and the three high fuel price sensitivity cases. For continuity with the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper, it also shows the annual total CO_2 emissions for the Interim Base Case and High Capital Cost Case of that paper.[25]

In the reference case the significant reduction in annual total CO_2 emissions is driven by a switch in the dispatch order of coal-fired and natural gas-fired resources.[26] The results of the High Fuel/$43 CO_2 Price Case show that this reduction in total emissions is sensitive to high natural gas prices. While some reduction in CO_2 emissions is achieved, with natural gas prices in the $8 to $9 per MMBtu range the $43 per ton CO_2 allowance price fails to reduce CO_2 emissions to the 1990 level. This is because the higher cost of natural gas favors the dispatch of coal-fired generating resources. With the higher natural gas prices the $43 per ton CO_2 emission cost is not sufficient to move coal-fired generation to the margin during a significant number of hours each year.

[25] See Figure 6, p. 11, in the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper.
[26] See the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper (pp. 7 - 16).

Figure 2: Forecasts of the Northwest power system's total CO_2 emissions

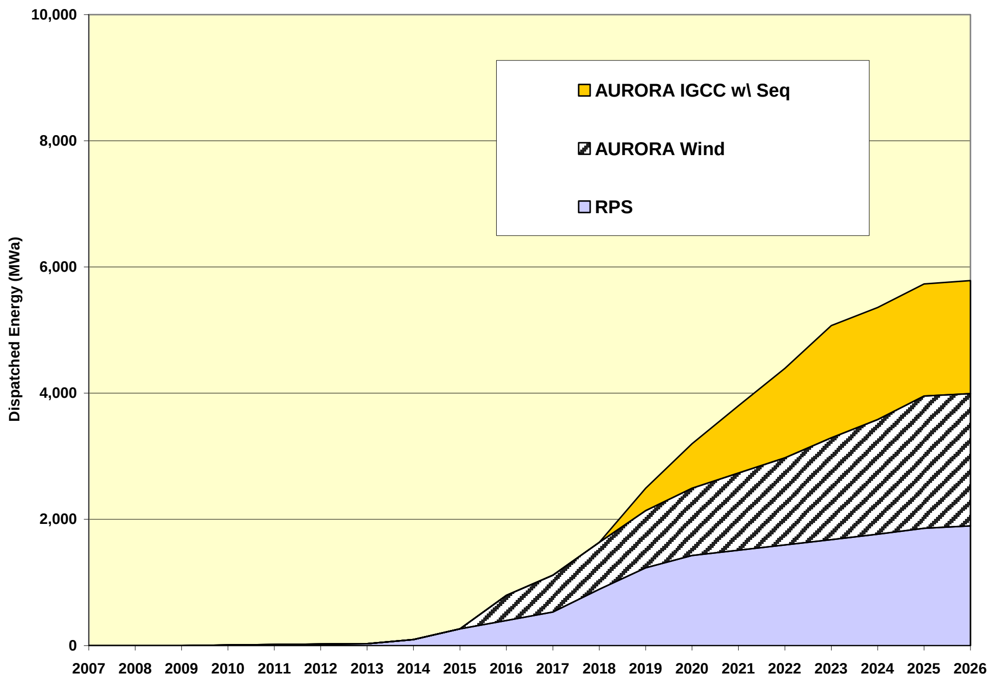


The results for the High Fuel/$70 CO_2 Price /Fixed Mix Case show that under the Council's high fuel price assumptions the price of CO_2 emissions allowances would need to climb to as high as $70 per ton of CO_2 in order for the Northwest power system to reach its 1990 level of CO_2 production with the resource mix of the reference case. The high natural gas prices work against efforts to reduce Northwest CO_2 emissions by forcing the cost of CO_2 allowance prices to climb in order to achieve the same targeted reduction in emissions.

The results for the High Fuel/$70 CO_2 Price /New Mix Case easily achieve 1990 levels of CO_2 emissions and show a continued decline in annual total CO_2 emissions after 2015. This is because additional wind generation (beyond Renewable Portfolio Standard requirements) and integrated gasification combined cycle (IGCC) generation with carbon capture and sequestration become economic additions to the power system. In addition, two large coal-fired generating units, Boardman and Valmy 1, become uneconomic to operate under these assumptions and are and retired in 2013 and 2020 respectively.[27] Figure 3 shows the energy output of the incremental resources added to the Northwest power system over the planning period. The continuing decline of CO_2 emissions observed in this case suggest that over the long-term, CO_2 allowance prices of less than $70 per ton of CO_2 may be sufficient to maintain emissions below 1990 levels, even with high natural gas prices.

[27] The Boardman unit is also retired in the reference case in 2012.

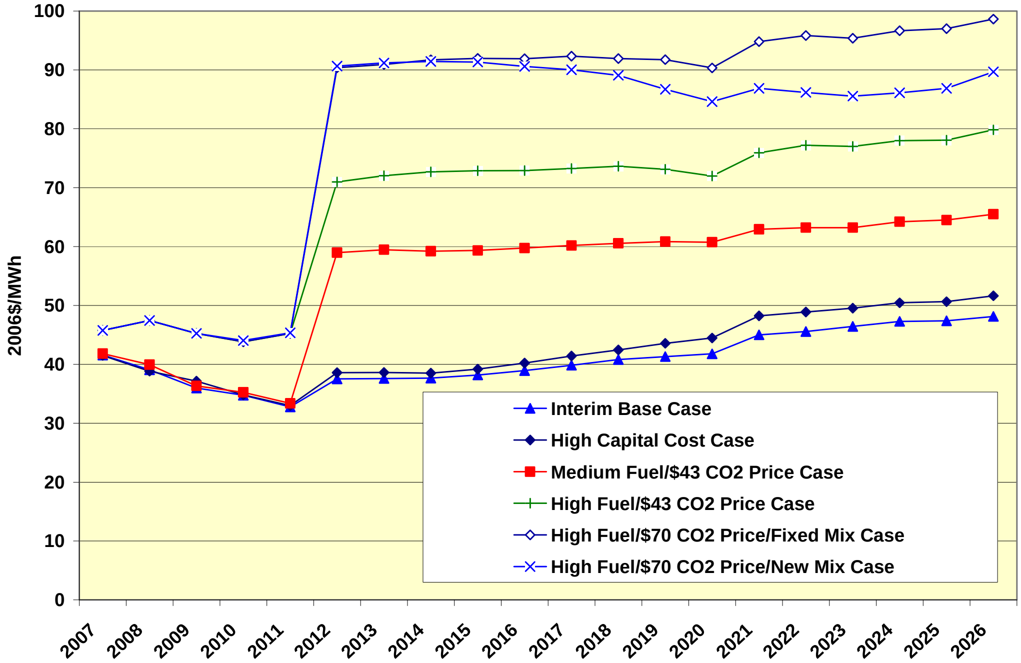
Figure 3: Forecast Pacific Northwest incremental resource mix based on dispatch energy (High Fuel/\$70 CO_2 Price/New Mix Case)



In its Fifth Power Plan the Council assumed that IGCC plants with CO_2 capture and sequestration using unconventional sequestration media (i.e., other than enhanced oil or gas recovery) could be in service in the region in the 2015 - 2020 period. Because of disappointingly slow development of the technologies involved it is uncertain whether five IGCC plants with carbon capture and sequestration could be built in the Northwest between 2019 and 2026. Moreover, because of the absence of relevant plant construction experience, the cost and risk of carbon sequestration is difficult to estimate. The Council will continue to improve its assumptions regarding this technology as it develops the Sixth Power Plan.

Whether CO_2 allowance prices of \$70 per ton of CO_2 would be politically sustainable for a prolonged period of time is also an open question. Many of the cap-and-trade proposals introduced in the 110th Congress call for "safety valve" options designed to release the CO_2 emissions cap if the cost of compliance becomes unacceptably high. Figure 4 shows the forecast wholesale power prices for each of the scenarios studied. The high fuel price sensitivity cases with \$70 per ton CO_2 allowance prices have the highest forecast power prices. For example, the High Fuel/\$70 CO_2 Price/New Mix Case had a levelized wholesale power price of \$73.70 per megawatt-hour (MWh). This is \$20.90 per MWh higher than the levelized price of the reference case. The High Capital Cost Case presented in the Council's "Interim Wholesale Power Price Forecast" paper had a levelized wholesale power price of \$41.30 per MWh. However, a \$70 per ton of CO2 allowance price appears to be more than sufficient to reduce CO2 emissions to 1990 levels, raising the possibility that somewhat lower allowance prices may suffice to achieve this objective, even with high natural gas prices. Moreover, a portion of the allowance revenues would likely be redirected to energy efficiency measures and low carbon generation, partly offsetting the overall cost of power system operation.

Figure 4: Forecasts of Northwest wholesale power prices



CONCLUSION

An important modeling result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," is that the Northwest power system's annual CO_2 emissions can be driven below its1990 level with CO_2 allowance prices of $43 per ton. This result was achieved at the Council's medium fuel price forecast.

The findings presented in this addendum demonstrate that this modeling result is sensitive to higher natural gas price forecasts. At the Council's high fuel price forecast the $43 per ton CO_2 emission cost is insufficient to achieve the same dramatic reduction in the total annual emissions of the Northwest power system.

The higher natural gas prices tend to work against efforts to achieve significant reductions in total CO_2 emissions. This is because higher natural gas prices favor coal-fired generation by making natural gas-fired units more costly to operate. Our modeling indicates that with the Council's high fuel price forecast, CO_2 allowance prices would need to climb to a level between $43 and $70 per ton of CO_2 in order to reduce the Northwest power system's annual total emissions to its 1990 level.

The Council will continue to explore these issues as it develops its Sixth Power Plan. While a wide range of uncertainties regarding both fuel prices and CO_2 allowance prices will be incorporated in the Sixth Power Plan portfolio risk analysis, CO_2 reduction objectives can only be indirectly considered by subsequent examination of the CO_2 production implied by the resulting preferred resource portfolio.

Attachment 51.1

Terms of Reference:
BC Partnership for Energy Conservation and Efficiency

Context:

BC Energy Plan

In February 2007, the government of British Columbia released the BC Energy Plan: A Vision for Clean Energy Leadership (BC Energy Plan) which establishes ambitious provincial targets for energy conservation and reducing greenhouse gas emissions.

The BC Energy Plan includes the following relevant policy actions that call for greater collaboration and coordination among utility DSM programs and provincial energy conservation and efficiency policies and programs:

Policy Action 2: Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.

Policy Action 3: Encourage utilities and the BC Utilities Commission to pursue cost-effective and competitive demand side management opportunities.

Policy Action 4: Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

Utilities and Provincial Energy/Climate Change Targets

Since the release of the BC Energy Plan, provincial goals to reduce greenhouse gas emissions by 33% below current levels by 2020 and by 80% below current levels by 2050, and the Energy Plan target to achieve 50% of BC Hydro's incremental resource needs through conservation, have been enshrined in legislation.

Achieving these targets will only be possible through aggressive and coordinated action by the provincial government and public and private utilities, acting in concert with a broad range of stakeholders including industry, local government, relevant federal agencies, environmental NGOs, and the applicable trades.

Government is giving utilities new tools to help meet the targets. Amendments to the *Utilities Commission Act*, introduced on March 31, 2008, bring the legislation in line with the conservation, energy security and climate action goals of the BC Energy Plan. The amendments align the Act with the province's energy objectives — to encourage utilities to reduce greenhouse gas emissions, pursue energy conservation and efficiency, produce and obtain electricity from clean or renewable sources, develop energy transmission infrastructure and capacity in time to meet customers' needs, and leverage innovative energy technologies.

Developing an ongoing and focused partnership with utilities will also help to resolve potentially conflicting objectives, such as the tension between reducing greenhouse gas emissions from fossil fuels and reducing electricity usage to meet the BC Energy Plan conservation target.

Terms of Reference:
BC Partnership for Energy Conservation and Efficiency

BC Partnership for Energy Conservation and Efficiency

In March 2008, the Deputy Minister of the Ministry of Energy, Mines and Petroleum Resources announced the creation of the British Columbia Partnership for Energy Conservation and Efficiency, to work on setting targets and to contribute towards ensuring that the regulatory framework for the British Columbia Utilities Commission supports cost-effective demand-side management measures.

Steering Committee
The Partnership Steering Committee had its first meeting on March 18, 2008. A proposed membership list and objectives are outlined below. Depending on the subject matter of Steering Committee meetings, other stakeholders may be invited to attend individual meetings where items of particular interest to their sector are being discussed.

Working Groups
The following key issue areas have been identified as initial working groups (with examples of related projects in brackets) with others to be raised for discussion in 2009:

1. Built Environment (updated Energy Efficient Buildings Strategy),
2. Industrial Customers (Industrial Energy Efficiency Program),
3. Measurement, Analysis and Reporting Task Force (harmonized reporting on DSM measures and achievements –summer/fall 2008 only)

For discussion in 2009

4. Communities (Community Action on Energy and Emissions), and
5. Transportation (plug-in hybrids, alternative fuel highways, etc).

The role, composition and scope of the working groups will be defined by the Steering Committee. It is understood that the working groups will have broader membership than the Steering Committee and will provide recommendations and information to the Steering Committee for consideration.

Steering Committee Membership:

Government:

Ministry of Energy, Mines and Petroleum Resources (MEMPR):	Les MacLaren Andrew Pape-Salmon Erik Kaye Chris Frye
Climate Action Secretariat	Warren Bell
British Columbia Utilities Commission	Erica Hamilton

Terms of Reference:
BC Partnership for Energy Conservation and Efficiency

	Jim Fraser
Utilities:	
BC Hydro	Lisa Coltart Bev Van Ruyven
FortisBC	Mark Warren Michael Mulcahy
Terasen Gas	Doug Stout Sarah Smith
Pacific Northern Gas Ltd.	Craig Donohue

Steering Committee objectives:

1. Define a common vision for energy conservation and efficiency in British Columbia

2. Serve as a forum for coordinating key energy conservation and efficiency initiatives

3. Identify provincial policy opportunities and challenges, and identify and resolve conflicting policy directions.

4. Develop an integrated public and industry engagement strategy to foster a culture of conservation in British Columbia.

Steering Committee Projects

Note: The list below is a compilation of broad policy issues that cut across the various working group sectors and is proposed as the initial project list for the Steering Committee:

1. Agree on a common definition of cost-effective DSM programs, with a particular focus on avoided cost and achievable potential.
2. Review the regulatory framework of the *Utilities Commission Act* (as amended)and identify opportunities to further support cost-effective DSM programs.
3. Define a common platform for utilities to monitor and report out on their progress towards meeting provincial energy conservation and GHG reduction targets.
4. Define how to allocate ownership of, or credit for, energy conservation and GHG reduction achievements across utilities and other stakeholders if applicable.
5. Develop strategies to achieve provincial energy conservation and greenhouse gas reduction targets while minimizing any conflicts between the two.
6. Coordinate DSM programs to achieve current provincial targets and support upcoming sectoral strategies, i.e. the updated Energy Efficient Buildings Strategy, which underpin the provincial targets.
7. Propose improvements to DSM programs to provide greater assistance to low-income ratepayers.

Attachment 54.1

REFER TO ATTACHED SPREADSHEET

Attachment 56.1

Date

Commission Secretary
British Columbia Utilities Commission
Box 250, 900 Howe Street
Vancouver BC
V6Z 2N3

Via Fax 604-660-1102

To Whom It May Concern:

(Organization name and brief description here)

(Organization name) supports the Terasen Utilities in their Energy Efficiency and Conservation (EEC) application to the British Columbia Utilities Commission. The programs and expenditures outlined in the Terasen Utilities EEC application will complement and enhance the efforts of (Organization Name) to reduce energy usage and greenhouse gas emissions in British Columbia, while at the same time benefiting British Columbians by helping them to manage their energy consumption and bills.

(Organization name) further supports the financial treatment outlined by the Terasen Utilities in the EEC application, believing that investor-owned utilities should be encouraged to identify and pursue cost-effective DSM programs. The financial treatment outlined minimizes the impact that the proposed EEC expenditure has on ratepayers, while providing a fair return to the Terasen Utilities for undertaking demand side management activity.

Sincerely,

XXX
Title

Terasen Gas applies to help British Columbians save energy and reduce greenhouse gas emissions

May 28, 2008

SURREY, B.C.- Terasen Gas is working to help British Columbians save energy, reduce greenhouse gas emissions and lower their energy bills through a new Energy Efficiency and Conservation Application filed with the B.C. Utilities Commission today.

“Natural gas plays an important role in B.C.’s energy mix,” said Randy Jespersen, Terasen Inc. President and CEO. “Terasen Gas delivers 20 per cent of the energy consumed in the province which is about equal to the amount of electricity used in B.C. This make energy efficiency and conservation an ongoing priority for us - in our own operations and also for our customers.”

“If approved, our application will significantly enhance the energy efficiency tools and incentives we provide to residential customers and businesses,” said Jespersen. “Such enhancements will help customers save energy, lowering their annual bills and reducing greenhouse gas emissions.”

The application requests $56.6 million in funding for programs and initiatives that by the end of 2010 would help British Columbians collectively reduce their natural gas use by about 1.5 million gigajoules per year, enough to serve 15,000 new households annually.

These energy savings would generate long-term financial and environmental benefits. Customers would collectively lower their annual natural gas bills by approximately $19 million and realize those financial savings each year over the lifespan of the appliance or system installed as a result of programs stemming from the application. Environmental benefits would include reducing 78,500 tonnes of greenhouse gas emissions annually, the equivalent of removing almost 16,000 vehicles from the road each year.

For residential gas customers, the application means Terasen Gas’s historic equipment upgrade offers would expand beyond furnaces to include fireplaces, water heaters, dishwashers, washing machines and clothes dryers.

Commercial and institutional buildings present other considerable opportunities for energy savings. Programs would be launched for retrofits of existing boilers with more efficient models, and for building re-commissioning.

Terasen Gas’s application supports many of the key policy actions called for in the Government of British Columbia’s 2007 Energy Plan, including: encouraging utilities to pursue cost-effective, conservation and energy efficiency opportunities; ensuring a coordinated approach to conservation and efficiency is actively pursued in B.C.; and policy actions around BC Hydro’s conservation goals and provincial energy self-sufficiency.

Terasen Gas is requesting a decision on the application by August 15, 2008. If approved, programs would start to roll out this fall providing Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. customers with the same access to energy saving opportunities.

Today's application builds on the company's efficiency and conservation activities over the past six years which have incented B.C. residents to reduce their annual consumption by almost one million gigajoules, realizing more than $7 million in savings and seeing a reduction of 50,000 tonnes of greenhouse gas emissions each year.

Terasen Gas delivers natural gas and propane through three companies that make up the Terasen Gas group: Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. The companies share common Terasen Inc. ownership and are indirect wholly owned subsidiaries of Fortis Inc. Fortis Inc., the largest investor-owned distribution utility in Canada, serves two million gas and electric customers and has more than $10 billion of assets. Its regulated holdings include Terasen Gas and electric utilities in five Canadian provinces and three Caribbean countries. Fortis Inc. owns non-regulated hydroelectric generation assets across Canada and in Belize and upper New York State. It also owns hotels and commercial real estate in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com.

Media contact:
Joyce Wagenaar
Director, Corporate and Marketing Communications
(604) 592-7682
joyce.wagenaar@terasengas.com

TERASEN GAS INC.

and

TERASEN GAS (VANCOUVER ISLAND) INC.

ENERGY EFFICIENCY AND CONSERVATION PROGRAMS APPLICATION

May 28, 2008

Executive Summary

Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI"), (collectively referred to as the "Companies" or the "Terasen Utilities"), herein apply, pursuant to section 44.2 of the *Utilities Commission Act* (the "Act"), for approval of increased expenditures in support of an expanded Energy Efficiency and Conservation ("EEC") strategy, and approval to capitalize incremental EEC expenditures by charging the expenditures to a regulatory asset deferral account and amortizing the balance over 20 years. The specific relief sought is set out in Sections 2 and 6 of the Application, and is summarized in greater detail below. The Companies believe that the strategy outlined in this Application, and the related relief sought, is consistent with government's energy objectives as defined by the Act, is cost effective, and is in the interest of persons in British Columbia who receive or may receive service from the Companies. The Terasen Utilities respectfully submit that the relief sought should be granted. Approval is respectfully requested by August 15, 2008 in order to permit implementation of the EEC strategy as early as possible.

Funding for Terasen Gas (Whistler) Inc. ("TGW") has not been included in this Application, primarily due to the timing of the conversion from propane to natural gas, and the need for additional analysis once that work is completed. An EEC plan, including funding, appropriate to TGW will be developed following receipt of an appliance conversion audit currently being conducted by TGW as part of the pipeline extension project from Squamish to Whistler.

The Companies' EEC activity, referred to in previous filings with the Commission as Demand Side Management ("DSM") activity, has remained essentially unchanged since the late 1990's. For TGI, funding levels were established by Order No. G-85-97, at approximately $1.50 million for incentives, which funds were to be placed in a deferral account and amortized over three years. Additionally, non-incentive expenses of approximately $1.624 million annually are treated as Operations and Maintenance ("O&M") expense and are expensed in the year in which they are incurred. EEC initiatives for TGI have been focused on conservation.

For TGVI, Order No. C-02-05 directed TGVI to develop an EEC strategy and budgets, and to seek approval through the Resource Plan process for DSM strategy and budgets. TGVI has historically had EEC expenditures of approximately $650,000 annually for incentives, plus $500,000 annually for non-incentive costs. Incentive expenditures are placed in a deferral account and fully amortized the year following that in which they were incurred. Non-incentive costs are treated as O&M and are expensed in the year in which they are incurred. EEC initiatives for TGVI have been focused on capturing additional economic customers within the TGVI service area (load-building) and encouraging customers using other fuels to connect to the natural gas distribution system (fuel-switching).

The Terasen Utilities have enjoyed success with the limited funding that they have had available for EEC activity. 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.

This Application fulfills the commitment the Terasen Utilities made in their respective negotiated settlement agreements to bring forth such an Application addressing EEC. Commission Order No. G-33-07 approved the extension for 2008-2009 of the 2004-2007 TGI PBR Settlement Agreement[1] ("TGI PBR Extended Settlement"); and Order No. G-34-07 approved the extension for 2008-2009 of the 2006-2007 TGVI Revenue Requirements Negotiated Settlement Agreement[2] (TGVI RR Extended Settlement") (collectively the "Extended Settlements").

Although the Companies have enjoyed success with the current EEC programs, existing budget constraints have not allowed the Companies and customers to take full advantage of the potential energy savings activity available. A great deal has changed since the Companies' approved levels of EEC expenditures were established, and there is an opportunity to expand EEC strategies in a manner consistent with government's energy objectives, with favorable results for customers. Rising energy costs - in BC, natural gas rates have more than doubled since 1998 - present greater potential for cost effective EEC initiatives and have made the public more receptive to these initiatives. An expanded EEC strategy for the Companies dovetails with government's energy objectives of, for instance, conservation, reduction of greenhouse gas (GHG) emissions, and electricity self-sufficiency. The Province set out

[1] Order No. G-51-03 approved the Terasen Gas Inc. 2004-2007 Multi-Year Performance-Based Rate Plan Settlement Agreement

[2] Order No. G-126-05 approved the Terasen Gas (Vancouver Island) Inc. 2006-2007 Negotiated Settlement Agreement

ambitious objectives regarding these items in its 2007 Energy Plan and has further demonstrated its commitment to these policies by enacting legislation to amend the *Utilities Commission Act* to require the Commission to address government's energy objectives in considering applications under section 44.2, among other things.[3] Despite the Province's leadership in developing conservation and GHG policies, the Terasen Utilities – which together are British Columbia's largest public utilities in terms of delivered energy - currently invest less on conservation in BC (in absolute dollars and on a per customer basis) than other utilities, both in BC and elsewhere in North America.

In 2005, the Terasen Utilities retained Marbek Resource Consultants Ltd. ("Marbek") to undertake a Conservation Potential Review ("CPR"), a review which had been contemplated in the 2004 Resource Plans for TGI and TGVI. The CPR was received by the Companies in 2006. The findings of the CPR were further refined through consultation with Habart and Associates Consultants ("Habart"). The Companies also developed "portfolio level" initiatives in addition to traditional energy efficiency and fuel switching programs. The strategies outlined in this Application, and the expenditures for which approval is being sought, are based to a significant degree on the findings of the CPR and the subsequent work undertaken with Habart. These cost-effective initiatives will lead to significant energy savings for customers and will result in a reduction in GHG emissions.

In summary, there are four components to the relief sought in this Application:

1. The Companies are seeking to expand overall EEC expenditures to a total of $56.6 million over three years, representing $46.944 million for TGI and $9.667 million for TGVI.
2. The Companies are proposing to capitalize incremental EEC expenditures, include them in a regulatory asset deferral account and amortize the balance of the account over a period of 20 years.
3. The Companies are proposing to increase the amortization period to 20 years for incentive amounts that are added to deferral accounts in 2008 and 2009 as part of the TG PBR Extended Settlement and TGVI RR Extended Settlement, which will align with the amortization period for incremental EEC expenditures.

[3] Bill 15, *Utilities Commission Amendment Act, 2008*

4. The Companies are proposing a methodology for evaluating the costs and benefits of the overall EEC portfolio.

The specific relief sought is detailed in Section 2 “Application”, but is summarized below.

Expanded EEC Funding

The TGI PBR Extended Settlement already includes DSM funding totaling $3.124 million ($1.50 million for incentives and $1.624 million for expense), in each of 2008 and 2009. Similarly, TGVI RR Extended Settlement includes DSM funding totaling $1.150 million ($0.650 million for incentives and $0.500 million for expense), in each of 2008 and 2009. The respective Extended Settlements specify how these DSM related expenditures are to be included in revenue requirements and rate determinations for 2008 and 2009. The two year total (2008 plus 2009) of DSM related expenditures for both Companies that are included in the Extended Settlements is $8.548 million ($3.124 million *2 plus $1.15 million *2). The Companies’ current approved EEC expenditures are outlined in Table 1 below.

The Companies are proposing incremental EEC/DSM expenditures over three years of $40.696 million for TGI and $7.366 million for TGVI. On a combined basis, the total additional funding for the three years ending 2010 over and above the approved levels stipulated in Extended Settlements for the two years ending 2009 is $48.062 million, bringing the three year total for both Companies to $56.61 million. This information is summarized in Table 1, below. While this funding increase will allow for a comprehensive set of expanded programs the Companies will continue to explore where the programs may be enhanced as experience is gained. Should beneficial opportunities be identified the Companies may bring additional applications forward as appropriate.

Table 1 – Current, Proposed, and Incremental EEC expenditures, by Utility

Current Level of Spend for 2008 and 2009 ($million)

Utility	O&M	Incentive	Total
TGI	$1.624	$1.500	$3.124
TGVI	$0.500	$0.650	$1.150
Total	$2.124	$2.150	$4.274

Proposed ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$13.996	$15.752	$17.196	$46.944
TGVI	$2.830	$3.043	$3.793	$9.666
Total	$16.826	$18.795	$20.989	$56.610

Incremental ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$10.872	$12.628	$17.196	$40.696
TGVI	$1.680	$1.893	$3.793	$7.366
Total	$12.552	$14.521	$20.989	$48.062

Much of the expenditure being requested, and the activity described in the Application, is based upon the CPR, conducted by Marbek, and received by the Companies in May 2006, as discussed in the 2006 Resource Plans for TGI and TGVI. The findings of the CPR were further refined through consultation with Habart, and the high-level program planning work was begun. The Companies also developed “portfolio level” initiatives in addition to traditional energy efficiency and fuel switching programs.

The Companies are seeking Commission approval for the overall incremental expenditures in Table 1 based on the contemplated program areas and funding described outlined in Table 2 below and described in detail 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. One of the program areas is $500,000 for a new CPR study to be completed in 2009 for the purposes of developing new EEC programs and funding proposals, including a future application to the Commission. The 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. The Terasen Utilities have proposed mechanisms in Section 6.14 to permit the Commission and stakeholders to review how the money has been spent and ensure accountability.

Table 2 - Proposed EEC Expenditure by Program Area

Spend by Program Area 2008 - 2010 ($000's)	TGI	TGVI	Totals
Residential Energy Efficiency	$8,552	$734	$9,286
Commercial Energy Efficiency	$19,592	$2,199	$21,791
Residential Fuel Switching	$1,332	$2,367	$3,699
Conservation Education and Outreach	$11,068	$2,767	$13,835
Joint Initiatives	$2,400	$600	$3,000
Trade Relations	$1,200	$300	$1,500
2009 Conservation Potential Review	$400	$100	$500
Innovative Technologies, NGV and Measurement	$2,400	$600	$3,000
Total	$46,944	$9,667	$56,611

The funding budgets for each program area were derived based on the Companies' expectation that they will be undertaking the initiatives identified in Section 6.

The Terasen Utilities believe that by targeting the above areas, the energy savings from the proposed increase in expenditure and activity are significant. The present value of the savings from energy efficiency is estimated to be almost 10 million GJs over the lives of the various measures proposed, while it is estimated that the proposed activities designed to switch people who currently use a less efficient energy source as compared to natural gas (i.e. fuel switching activities) would result in additional load with a present value of approximately 2.3 million GJs. The net energy savings from the contemplated energy efficiency and fuel-switching activity is anticipated to be approximately 7.7 million GJs. This does not include potential savings resulting from Conservation Education and Outreach, Joint Initiatives, or Innovative Technologies, NGV and Measurement. The Companies anticipate that the proposed EEC activity will continue to provide good value for customers in a manner that is consistent with government's energy objectives. For example, the Energy Efficiency activity that the Companies are contemplating for customers of TGI produces a simple yield of $3.15 spent/GJ saved. The EEC portfolio contemplated in this Application, when assessed in accordance with the proposed evaluation methodology, has a Total Resource Cost ("TRC") ratio of 3.1 and a net financial benefit to customers of $165.1 million.

The Companies will continue to assess over the course of the Program Period whether customers would benefit from additional EEC spending over and above the funding sought in this Application, and will bring forward any further applications as appropriate.

Financial Treatment

As discussed in more detail in Section 6, this EEC Application proposes to treat the incremental EEC expenditures above amounts already approved as part of TG PBR Extended Settlement and TGVI RR Extended Settlement as capital. An amortization period of 20 years has been selected to match the benefit received by customers from the EEC expenditures resulting in appliance and energy system installations with a weighted average measurable life of 22.5 years. In addition to closely matching the cost recovery to the period over which benefits will accrue to customers, the proposed amortization period will smooth impacts to rates from the proposed increase in expenditure. The Terasen Utilities propose that the incremental EEC expenditures and existing incentive amounts in TG PBR Extended Settlement and TGVI RR Extended Settlement (TG - $1.5 million and TGVI - $.650 million) be charged to a regulatory asset deferral account on a tax-adjusted basis, the balance of which is amortized over twenty years, with amortization commencing the year following the year the expenditure is made. As indicated above, the longer amortization period than the periods contemplated in the Extended Settlements will smooth the impact to rates from the proposed increase in expenditure, and is more representative of the longevity of the energy savings resulting from the expenditure and from the new appliances to be installed by customers as a result of expenditures. This financial treatment is consistent with an approach used by other utilities in British Columbia, and the approach identified in the Commission's 1995 Guidelines in respect of the financial treatment of DSM.[4]

Evaluation Methodology

The Application also outlines specific approaches for evaluating the performance of the programs undertaken. The Companies are proposing a portfolio approach to cost-benefit analysis, so that rather than evaluating cost-effectiveness on a program-by-program basis, the overall EEC portfolio must maintain a TRC ratio of 1.0 or higher. This approach will allow the Companies to undertake the important portfolio-level activities needed to support the EEC activity, as well as to encourage market penetration of technologies that have a TRC of less than one because they have not yet reached economies of scale but have longer term potential for a higher TRC ratio. Further, the portfolio approach will allow the Companies to offer programs to customers in service areas where the TRC may have a result of less than 1.0 due

[4] British Columbia Utilities Commission Order No. G-55-95, Amendments to the Uniform System of Accounts for Gas and Electric Utilities

to lower usage patterns, to support the Companies' goal of making the same programs available to customers across the service territory. The Companies propose that the "benefits" input to the cost-benefit analysis be based on gross energy savings rather than net savings (thus eliminating consideration of the perceived effects of free riders), due in part to uncertainties around free ridership rates. Free riders are customers who participate in an EEC program, who notionally would have undertaken the same conservation actions even if the program were not offered. The Companies are of the view that the inclusion of the notional free rider effects in the cost-benefit tests for EEC programs will distort test results and consequently may lead to results that run counter to the objectives of energy policies. The Companies further propose that the "benefits" input to the cost-benefit analysis include energy savings resulting from future regulations that may be introduced partly as a result of the Companies' EEC activity. The TRC ratios referenced in the Application have been derived using this approach.

Mechanics of Implementation

As discussed above, the TGI PBR Extended Settlement includes DSM funding totaling $3.124 million ($1.50 million for incentives and $1.624 million for expense), in each of 2008 and 2009. Similarly, TGVI RR Extended Settlement includes DSM funding totaling $1.150 million ($0.650 million for incentives and $0.500 million for expense), in each of 2008 and 2009. The respective Extended Settlements specify how these DSM related expenditures are to be included in revenue requirements and rate determinations for 2008 and 2009. The two year total (2008 plus 2009) of DSM related expenditures for both Companies that are included in the Extended Settlements is $8.548 million ($3.124 million *2 plus $1.15 million *2).

The Terasen Utilities propose that the incremental expenditures for the 2008 and 2009 years be added to the DSM expenditures that have previously been approved by the Commission for inclusion in the Companies respective revenue requirements and rate determinations as set out in the Extended Settlements for 2008 and 2009.

The result of the mechanics described above based on the EEC expenditures proposed with this Application, the Companies expect that total EEC expenditures of $14.702 million ($16.826 less $1.624 less $0.500) will be added to the deferral accounts of the Terasen Utilities in 2008 on a before tax basis. The 2008 amortizations will remain unchanged from the amounts approved under the previous TGI Annual Review and the TGVI Settlement Update. Amortization for 2009 will equal one-twentieth ($1/20^{th}$) of the forecasted year ending balance in the deferral account as at December 31, 2008. For 2009, in aggregate, the Companies expect that $16.671 million ($18,795 million less $1.624 less $0.500) will be added to the deferral accounts of the Terasen Utilities on a before tax basis. The deferral accounts will be included in rate base, on an after tax basis.

Stakeholders

The Terasen Utilities have undertaken to consult with stakeholders in its preparation of the Application. Feedback has been generally supportive. In consideration of this feedback, the Companies are of the view that a written regulatory review process culminating in a Negotiated Settlement Process is appropriate for this Application.

Conclusion

The Companies are of the view that proposals set out in this Application are consistent with government's energy objectives and will provide significant value to customers. Additionally, the Companies are of the view that the capitalization of incremental EEC expenditures is reasonable in light of the significant benefits that customers will realize with the successful introduction of the EEC programs proposed with this Application. The proposed portfolio approach to evaluation will allow the companies to undertake a broad range of programs throughout the Companies' service area. Accordingly, the Terasen Utilities are of the opinion that the proposals set out in this Application are fair, reasonable and in the best interests of customers.

6.3. Energy Efficiency Program Areas

Under the Companies' current guidelines, customer-level marketing and energy efficiency activities for the Lower Mainland and Interior are different from those for Vancouver Island. For the Lower Mainland and Interior, DSM activities at TGI are focused solely on peak shaving and conservation initiatives (also termed "energy efficiency" throughout this document) that aim to reduce natural gas usage by customers, and do not encompass other aspects of DSM such as load building through encouraging fuel switching. TGVI currently only offers customers fuel switching programs, and does not offer customers energy efficiency programs. With this Application, the Companies would like to expand EEC activities so as to offer all customers, regardless of service territory, access to an expanded array of programs. That is, the Companies would like to be able to offer customers on Vancouver Island access to energy efficiency programs and would like to offer Lower Mainland and Interior customers access to fuel switching programs.

The information presented in this sub-section regarding energy efficiency program areas is done so sector (Residential and Commercial) basis. The Residential and Commercial sectors are broken down into initiatives intended for new construction and initiatives intended for the retrofit market. Fuel substitution program area and activities are described under Section 6.4.

6.3.1. Residential Energy Efficiency Program Area ($9.2 million)

Energy Efficiency programs for the residential sector fall under two types of offers – new construction and retrofit. They are summarized in Table 6.3.1 below.

Table 6.3.1 - Residential Energy Efficiency

Program	Components	TGI	TGVI
Residential Energy Efficiency – New Contruction			
EnerChoice Fireplace	EnerChoice Fireplace	X	X
ENERGY STAR Appliances	E* Clothes Washer	X	X
	E* Dish Washer	X	X
Residential Energy Efficiency - Retrofit			
ENERGY STAR Furnace Upgrade	E* Furnace	X	X
EnerChoice Fireplace Upgrade	EnerChoice Fireplace	X	X
ENERGY STAR Appliance Upgrades	E* Clothes Washer	X	X
	E* Dish Washer	X	X

Energy Efficiency for Residential New Construction

The program is targeted at all potential residential new construction customers. It is intended to be complementary to the Companies' System Extension and Customer Connection Policies Review Application, submitted to the BCUC July 31, 2007. In Order No G-152-07 of December 6, 2007 the Commission stated that "Terasen is encouraged to apply for the approval for such [DSM] programs in another forum, where their impact and efficiency as DSM programs can be tested." This document constitutes the Companies' Application for DSM programs for the New Construction market. The key decision makers in this market for the programs detailed below are builders and developers who build single family homes and row-houses. In addition, a number of single-family homes are project-managed by the owners themselves who make planning and purchasing decisions and could be considered in an outreach campaign. There may also be some builders of multi-family dwellings that participate in the incentive programs outlined below. The new construction EEC portfolio in the residential market will include programs that encourage customers, whether they be individuals building a new home, or builders and developers, to install energy efficient appliances. The following programs will be offered to customers and builders:

EnerChoice Fireplace - an incentive will be provided to encourage the purchase and installion an EnerChoice rated fireplace, insert or free-standing stove. (Since there is no Energy Star designation for fireplaces, the Hearth Products Industry has developed the EnerChoice designation, which is applied to fireplaces that are in the top 25% efficiency ranking out of all the fireplaces available in the marketplace.)

Energy Star Clothes Washer and/or Dishwasher – similar to the program offered to customers in the retrofit market, participants who use natural gas as a heating source for Domestic Hot Water ("DHW") will be encouraged to install an Energy Star dishwasher and/or Energy Star clothes washer. The incentive amount will be based on whether they choose to install one or both appliances.

Energy Efficiency for Residential Retrofits

The retrofit program targets all existing residential customers of the Terasen Utilities. The key decision makers in this market are owners and possibly landlords of single-family and row-houses who are either replacing failed equipment or looking to upgrade/improve energy efficiency in existing housing stock.

The retrofit programs will consist of a combination of advertising and promotion and incentives for customers who install Energy Star and/or EnerChoice rated products.

Energy STAR Heating System Upgrade – this program will be a reiteration (since similar versions of this program have been running for a number of years) of the TGI Energy Star Heating System Upgrade program. Customers who install an Energy Star heating system will receive a credit on their Terasen Utilities bill. It should be noted that due to new federal regulations for furnace upgrades in retrofit residential buildings coming into effect December 31, 2009, this program will conclude prior to that date.

At the time that the CPR was conducted, there were found to be a total of 1,534,248 residential units in the TGI service area, of which 155,809 units were pre-1976 single family dwellings ("SFD") or duplexes with gas.[28] These dwelling units would be good candidates to upgrade existing furnaces to high-efficiency models. To contextualize the projections used to derive the

[28] Terasen Gas Conservation Potential Review, Residential Sector Report, Marbek Resource Consultants, April 2006, page 8

funding levels in this Application, the Application contemplates funding a total of 8,180 furnace upgrades up to the end of 2009, at which time a federal regulation is proposed that would make 90% efficiency levels the minimum for all furnaces sold in Canada so utility incentive funding is assumed to cease. This incentive participation level represents funding for incentives for furnace upgrades in 5.3% of pre-1976 single family dwellings ("SFDs") and duplexes with gas in the Companies' service territory, and it is based upon current program participation rates.

EnerChoice Fireplaces – customers will be incented if they purchase and install an EnerChoice rated fireplace, insert or free-standing stove. The pilot program will be launched in 2008 in partnership with Hearth, Patio & Barbeque Association of Canada (HPBAC) who will provide assistance in promotional and educational aspects of the program.

Energy Star Appliances – existing customers who use natural gas as a heating source for Domestic Hot Water ("DHW") will be encouraged to install an Energy Star dishwasher and/or Energy Star clothes washer. The incentive amount will be based on whether they choose to install one or both appliances. These measures provide savings by reducing the amount of water that needs to be heated by gas, but they also result in ancillary electricity savings from more efficient electric motors.

The Energy Star Heating Upgrade Initiative has existed in different forms since the current level of DSM funding available to TGI was established in 1997. In the 1997 DSM Semi-Annual Status Report, submitted by BC Gas Utility Ltd. on November 19, 1997, the number of participants in the heating upgrade program was 68 at the time of reporting, projected to grow to 205 by year-end. This year's program, running as noted above from September 1 2007 to March 31 2008 is projected to have 3300 participants, a notable gain in program participation.

6.3.2. Commercial Energy Efficiency Program Area ($21.7 million)

As with the residential sector, energy efficiency initiatives for the commercial sector will also fall under retrofit and new construction programs.

Energy Efficiency for Commercial New Construction

The new construction program is targeted at all commercial new construction which might use natural gas space and water heating. Looking at current new commercial construction, the immediate opportunities are likely to be Multi-Family Dwellings ("MFDs") and Commercial office space. Eligible buildings may also include some institutional (government buildings, schools and post-secondary institutions). It should be noted that incentives, building design and heating and hot water systems for MFDs are covered by the program proposals below, in the Commercial Section of this program activity description, rather than in the Residential Section.

The key decision makers in this market are owners including: governments; builders/developers; architects; engineers; interior designers; mechanical consultants; and contractors.

Table 6.3.2 below lists some potential areas for activity in the Commercial New Construction sector. Program design is complex in the Commercial New Construction sector, so the table below merely summarizes areas of program activity.

Table 6.3.2 - Commercial Energy Efficiency - New Construction

Program	Components	TGI	TGVI
Efficient New Construction	Efficient Design (30% Below Current Practice, Large Commercial Buildings)	X	X
	Efficient Design (30% Below Current Practice, Medium Commercial Buildings)	X	X
	Efficient Design (60% Below Current Practice)	X	X
	High Insulation Technology (HIT) Windows	X	X
Boilers	Near Condensing Boilers	X	X
	Condensing Boilers	X	X
Water Heating	Instantaneous DHW Heaters	X	X
	Condensing DHW Boilers	X	X
	Condensing DHW Heaters	X	X
	Drainwater Heat Recovery	X	X

Energy Efficiency for Commercial Retrofits

The commercial retrofit program is targeted at all commercial and industrial buildings with existing natural gas fired space and water heating equipment. These include, but are not limited to:

- MFDs and commercial office space;
- Institutional (any government buildings, post-secondary campuses and schools);
- Hospitals;
- Hotel/motel buildings;
- Malls.

The key decision makers for retrofit equipment replacement decisions are building managers and owners.

There are two drivers for replacing/upgrading existing equipment in retrofit markets: equipment at the end of life and products that are replaced before the end of life to obtain energy efficiency savings. The table below lists some potential areas for activity in the Commercial retrofit market. Due to the potential complexity of programs for the commercial sector, Table 6.3.2a below merely summarizes areas of program activity. More detailed program development work must be completed by the Companies in conjunction with industry groups before these programs are rolled out.

Table 6.3.2a - Commercial Energy Efficiency - Retrofits

Program	Components	TGI	TGVI
Boilers	Near Condensing Boilers	X	X
	Condensing Boilers	X	X
Building Recomissioning		X	X
Next Generation Building Automation Systems (“BAS”)	Next Generation BAS	X	X
Demand Control Ventilation (“DCV”)	DCV (Large Commercial Buildings)	X	
	DCV (Medium Commercial Buildings)	X	
High Efficiency (“HE”) Rooftop Units	HE Rooftop units	X	X
Water Heating	Instantaneous DHW Heaters	X	X
	Condensing DHW Boilers	X	X
	Condensing DHW Heaters	X	X
	Drainwater Heat Recovery	X	

Programming for the Commercial sector in general is intended to offer qualified commercial customers a menu of programs from which to choose. Terasen Utilities staff will work with the participants in selecting the most appropriate program and/or component.

6.4. Residential Fuel-Switching Program Area ($3.7 million)

The Terasen Utilities firmly believe that the use of natural gas where available for high-efficiency end-use appliances in place of electricity results in lower GHG emissions overall in the region, as it makes more of BC's "green" electricity resource available to its best use to displace coal and lower efficiency gas fired generation throughout the region.[29]

Fuel substitution initiatives benefit all customers by ensuring that the Terasen Utilities' distribution infrastructure is used to its maximum efficiency. This is especially true of TGVI, where homes that have not made the step to connect to gas exist in proximity to gas mains. Existing customers have already invested in putting those gas mains in the ground, therefore connecting as many customers as possible to the natural gas distribution system will keep overall system costs down. It should be noted that the 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, and onto efficient natural gas, resulting in lower GHG emissions. Table 6.4 below summarizes at a very high level the program areas for fuel switching activity.

Table 6.4 - Residential Fuel Switching

Program	Components	TGI	TGVI
Residential Fuel Switching – New Construction			
Natural Gas Water Heating	NG DHW		X
Natural Gas Appliances	NG Range	X	X
	NG Dryer	X	X
Residential Fuel Switching – Retrofits			
Natural Gas Appliances	FS Range		X
	FS Dryer		X
Furnace Fuel Substitution	Furnace		X
Fireplace Fuel Substitution	EnerChoice Fireplace		X

[29] Coal and gas fired generation are on the margin throughout the western interconnection. New combined cycle gas turbines operate at only approximately 50% efficiency, whereas newer natural gas water heaters and space heaters can operate as high as 95% efficiency.

Fuel Switching for Residential New Construction

Provincial regulations taking effect January 1, 2008, require that all natural gas forced air furnaces in all new construction meet the Energy Star standard. This presents two major areas of concern from the perspective of fuel efficiency and GHG emissions. As discussed previously, gas water and space heating is more efficient and results in lower GHG emissions on a regional basis than electric space and water heating. First, the higher relative cost of the Energy Star rated natural gas furnaces may persuade some builders to switch to electric space heat. Second, non-Energy Star natural gas furnaces were able to be vented in such a manner ("b-vented") that the vent for the furnace could be shared with the vent for a natural gas hot water tank. Energy Star furnaces cannot share a vent with a natural gas hot water tank, so the regulation for Energy Star furnaces may cause builders to install electric hot water installations to avoid the cost of venting for the already more expensive natural gas hot water tank.

To encourage the usage of natural gas among its customers, the Terasen Utilities would offer the following fuel-substitution programs:

Installation of **natural gas water heating** along with natural gas space-heating equipment – the Companies may bundle this program as a package with Energy Star appliances.

Installation of **natural gas range** and/or **dryer** – TGVI and TGI qualified applicants will receive an incentive if they install one or both appliances.

The primary objective of the fuel-switching offers is to promote the most optimal balance in energy share between electricity and natural gas, preserving BC Hydro's generation and transmission systems for its highest value – in running lights, computers and other technology.

Fuel Switching for Residential Retrofits

TGVI has been running residential programs on Vancouver Island and the Sunshine Coast for a number of years. These programs have encouraged owners of existing homes on Vancouver Island and the Sunshine Coast to convert from higher emission propane and fuel oil to natural gas. Incentive funding for fuel substitution retrofits is only contemplated for TGVI and not for TGI, as it is felt that the bulk of the potential in the TGI service territory has already been addressed. The benefits from fuel substitution programs for existing homes on Vancouver

Island as described below are significant: GHG emissions are reduced through the switch from wood, propane or fuel oil to natural gas for space heating and fireplaces, and BC Hydro and BCTC avoid adding additional capacity to serve water heating, cooking and clothes drying load on an already stressed transmission and distribution system. TGVI would like to initiate a fuel-substitution portfolio intended to retrofit homes on Vancouver Island to include the following programs:

Natural Gas Heating System Upgrade - customers who switch to a natural gas heating system in an existing home will receive an incentive from Terasen Gas. Existing residences in the TGVI service territory will be offered an incentive not only for switching to natural gas, but also for installing Energy Star equipment. The current regulatory regime for TGVI does not allow Terasen to offer customers who switch to natural gas an incentive to install Energy Star equipment. We would like to be able to do so and would in fact restrict the provision of an incentive to furnaces and boilers rated Energy Star.

Fireplace - customers in existing homes will be incented if they purchase and install an EnerChoice rated fireplace, insert or free-standing stove.

Natural Gas Range and Dryer – these two additional fuel-switching programs will encourage customers to replace their existing electric or propane range and/or an electric or propane dryer to a natural gas range and/or dryer.

Instructions for Registering to Participate in a British Columbia Utilities Commission Application Review Process or Regulatory Proceeding

There are several ways in which an individual, group or organization may register to participate in a British Columbia Utilities Commission ("BCUC" or the "Commission") Application Review Process or Regulatory Proceeding.

Registration:

1. **On-Line Registration:**
   Registration can be completed on-line by typing this ULR address into your browser navigation address bar http://www.bcuc.com/Registration.aspx or go to the www.bcuc.com website, on the left-hand navigation bar select "File or Register", select "Registration". A form will be presented for completion.

2. **Registration by Correspondence:**
   A letter or e-mail can be addressed to the Commission Secretary and submitted by e-mail, fax or mail so long as it is received by the Commission Secretary prior to the registration deadline established for the process. Preference is for electronic submission of communications if possible.

Mail to:	The Commission Secretary British Columbia Utilities Commission Box 250, 900 Howe Street Vancouver, BC V6Z 2N3
Facsimile to:	604-660-1102
E-mail to:	**Commission.Secretary@bcuc.com**

Forms of Participation:

Interventions:

An intervention is a document sent to the Commission to express an intention to participate in a public hearing (Registration). It may take the form of a formal legal submission, a position statement, letter or a hand-written letter which must be received by the Commission Secretary before the deadline established. Letters or Notices of Intervention can be submitted electronically by e-mail as an attachment, or by completing the on-line registration.

Participation Roles (as described on the Commission website):

1. **Intervenor** – an individual, group or organization that has an interest in actively participating in a particular application review process or regulatory proceeding.
2. **Interested Party** – an individual, group or organization that has an interest in a particular application or proceeding, but only as an observer and does not intend to actively participate.

Letters of Comment:

Individuals, groups or organizations may wish to file a letter of comment into the official public record of the proceeding for a particular application, but do not wish to participate in the hearing process. These letters are entered into the official record as part of an Exhibit as a letter of comment from an interested party and can be submitted in the same manner as Registration by Correspondence.

More information on Participation and the Regulatory Process can be found at the Commission's website www.bcuc.com or in the Commission's publication *"Understanding Utility Regulation – A Participant's Guide to the British Columbia Utilities Commission",* available on the BCUC website at the following link: http://www.bcuc.com/Documents/Guidelines/Participant_Guide.pdf

-----Original Message-----
From: Greaves, Carol [mailto:Carol.Greaves@terasengas.com]
Sent: July 2, 2008 11:37 AM
To: 'kmelamed@whistler.ca'; 'Graham.hill@town.viewroyal.bc.ca'; Mayor (Alan Lowe); 'isutherland@squamish.ca'; 'jevans@district.sooke.bc.ca'; 'damos@sidney.ca'; 'creid@district.scehlet.bc.ca'; 'jack.mar@csaanich.ca'; 'mayor@saanich.ca'; 'mayor@qualicumbeach.com'; 'citypa@city.port-alberni.bc.ca'; 'info@cdpr.bc.ca'; 'sherle@parksville.ca'; 'mayor@oakbay.ca'; 'mayor@northsaanich.ca'; 'gary.korpan@nanaimo.ca'; 'mayor@district.metchosin.bc.ca'; 'council@lantzville.ca'; 'council@cityoflangford.ca'; 'rhutchins@ladysmith.ca'; 'mecardinal@shaw.ca'; 'bjanyk@gibsons.ca'; 'mayor@esquimalt.ca'; 'mayor@duncan.ca'; 'fbates@shaw.ca'; 'swinchester@courtenay.ca'; 'jbrass@comox.ca'; 'mayor@city.colwood.bc.ca'; 'mayor.mcdonell@campbellriver.ca'
Subject: Terasen Gas Energy Efficiency and Conservation Application to the BCUC

Dear Mayor

You may have heard that Terasen Gas has recently filed an application with the British Columbia Utilities Commission to seek funding for Energy Efficiency and Conservation programs for British Columbians.

Should the application be approved, programs will be designed to help people save energy, reduce greenhouse gas emissions and lower energy consumption and subsequently reduce energy bills.

We are actively seeking support from the communities we serve as we believe that our efforts will complement the efforts of your municipality in reducing energy usage and greenhouse gas emissions.

I attach a synopsis of the application for your review as well as our May 28th news release. You will also find a draft letter of support which we are asking you to complete and either fax ((604) 660-1102) or e-mail to the British Columbia Utilities Commission
Commission.Secretary@bcuc.com<mailto:Commission.Secretary@bcuc.com>

I have also attached instructions for registering to participate in a BCUC application review process. Please note that registration is only necessary should you wish to actively participate. You may submit your letter of support without registering to participate.

We are hoping that all letters of support will be submitted to the Commission by no later than July 25th.

If you have any questions or comments, please feel free to call or e-mail me.

Thanks very much for your support.

Carol

Carol Greaves
Community Relations Manager
Terasen Gas (Vancouver Island) Inc.
320 Garbally Road
Victoria, B.C.
V8T 2K1

Phone: (250) 380-5764

Fax: (250) 388-6876

From: Hennessy, Amy [mailto:]
Sent: Thursday, July 10, 2008 6:05 PM
Subject: Terasen Gas EEC application

Dear Mayor

You may have heard that Terasen Gas has recently filed an application with the British Columbia Utilities Commission to seek funding for Energy Efficiency and Conservation programs for British Columbians.

Should the application be approved, programs will be designed to help people save energy, reduce greenhouse gas emissions and lower energy consumption and subsequently reduce energy bills.

We are actively seeking support from the communities we serve as we believe that our efforts will complement the efforts of your municipality in reducing energy usage and greenhouse gas emissions.

I attach a synopsis of the application for your review as well as our May 28th news release. You will also find a draft letter of support which we are asking you to complete and either fax ((604) 660-1102) or e-mail to the British Columbia Utilities Commission Commission.Secretary@bcuc.com

I have also attached instructions for registering to participate in a BCUC application review process. Please note that registration is only necessary should you wish to actively participate. You may submit your letter of support without registering to participate.

We are hoping that all letters of support will be submitted to the Commission by no later than July 25th.

If you have any questions or comments, please feel free to call or e-mail me.

Thanks very much for your support.

Amy Hennessy

Amy Hennessy | **Community Relations Manager** | **Terasen Gas Inc.**
16705 Fraser Highway | Surrey BC V4N 0E8
☎: 604.576-7363 | 🖷: 604.576-7122 | ✉: amy.hennessy@terasengas.com

From: Smith, Sarah
Sent: Friday, June 13, 2008 4:16 PM
To: John Robinson (johnr@ires.ubc.ca)
Subject: Terasen Gas Energy Efficiency and Conservation (EEC) Application

John I trust that this email finds you well. I cannot believe that the sun has finally broken out!
I am hoping to solicit a letter of support from CIRES for our EEC Application. To that end, I attach a draft letter as a jumping off point, and a summary package of information about the Application. It would be very helpful to have a letter from CIRES on file as the Commission consider the application. All you need to do is fax the letter to the contact on the draft letter.
Thanks in advance, and if you have any questions at all, I can be reached at the number below.
Ciao for now!

Draft Letter of Support.doc (2...   EEC App keholder Handout.p

Sarah Smith
Manager, Marketing and Energy Efficiency, Terasen Gas
604-592-7528

BURN BLUE, SAVE GREEN

To find out more about how you can save money and energy, please visit our website at www.terasengas.com