Final Argument
Via Email

April 27, 2009

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

Dear Madam:

Re: British Columbia Hydro and Power Authority
2008 Long-Term Acquisition Plan Application

Please find attached the IPPBC's argument with respect to the above.

Yours truly,

"Original signed by David Austin"

David Austin

Cc BCH and Interveners

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BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE *UTILITIES COMMISSION ACT*

and

British Columbia Hydro and Power Authority
2008 Long-Term Acquisition Plan

FINAL ARGUMENT ON BEHALF OF

THE INDEPENDENT POWER PRODUCERS OF B.C.

April 27, 2009

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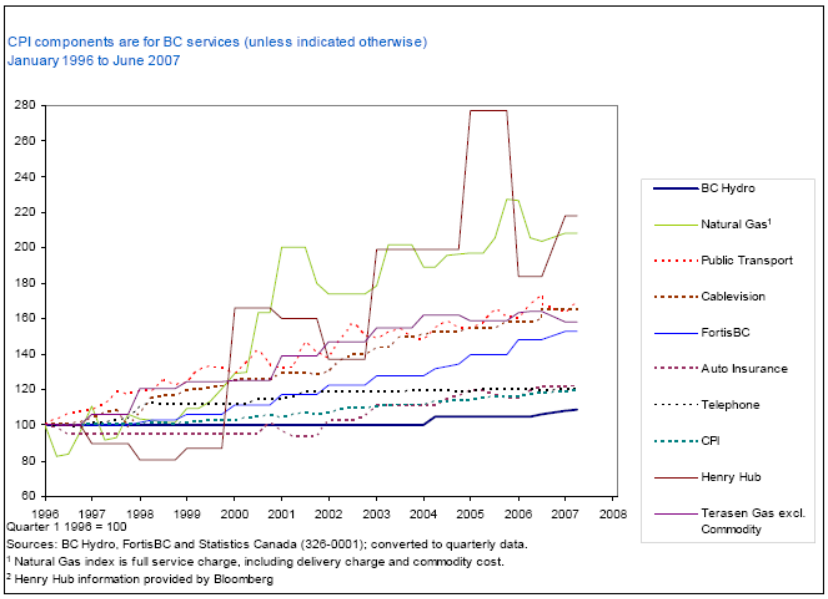
1. Introduction

It is a complex undertaking to estimate BC Hydro's ("BCH") demand for electricity and then to assess the resources that are available to meet it. British Columbia is endowed with a multitude of available conservation options and generating resources. Some are existing such as the Heritage Hydro resources with a deemed output of 42,600 GWh[1] under critical water conditions which is itself is a deemed standard[2].

In its 2008 Long-Term Acquisition Plan Application ("Application" or "LTAP"), BCH proposes including its antiquated and very inefficient Burrard Thermal generating plant ("Burrard") as a 900 megawatt and 3,000 GWh thermal Heritage generating resource. The facts do not support this proposal.

BCH has been rigorously pursuing conservation options since the 1970s and today's efforts bear a remarkable similarity to these early efforts. This raises the questions of the effectiveness of the existing programs and whether replacements are required.

Irrespective of legislative requirements[3] and provincial government energy policy[4], new generation can, and should be almost exclusively renewable. This generation isn't subject to carbon or fossil fuel price risks which were key BCH concerns as identified in the British Columbia Utilities Commission's 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan Decision [5] ("BCUC" and "BCUC 2007 LTAP Decision"). The volatility and price risk of natural gas at the Henry Hub pricing point are indicated by the following graph[6]:



[1] Exhibit B-1-1, Appendix B2, Section 1(2)
[2] Exhibit B-1-1, Appendix B2, Section (1) definition of "firm energy capability"
[3] For example, Utilities Commission Act, Section 64.02
[4] For example, Exhibit B-1-1, Appendix B-1, Policy Action Items 18-22
[5] May 11, 2007, page 107
[6] Exhibit B-87

Independent Power Producers ("IPPs") can, through competitive bid processes, supply BCH with a broad variety of renewable generation such as run of river, wind, biomass and geothermal at long term, fixed prices. In the BCUC's review ("Proceedings") of the "Application" erroneous comparisons have often made between the prices of this long term supply and short term open market prices or "spot prices" which include among other things, carbon and fossil fuel price risk.

These comparisons also ignore the lease provisions for Crown Land on which almost all renewable IPP generation will be built. At the end the term of these leases, the fixtures that are used to generate electricity, will at the option of the Crown, revert to it or be removed and the land restored as close as possible to its original condition. The IPP takes the development and construction risk plus the operating cost and fuel supply risk, such as water and wind flows. The price paid for the electricity is fixed usually for a term of 30-40 years and at the end of the lease, the Crown gets the fixed assets, free of charge, if it wants them[7]. In the 2008 Clean Power Call, BCH will also get the renewable energy credits ("RECs")

A lot of emphasis in the Proceedings was put on the current economic downturn and its impact on the amount of electricity BCH's customers require. These requirements are long term as evidenced by the following statements by the President of BCH:

> *"Strategically, when you look at the last 40 years or our load growth, there almost always is load growth. In other words, there have been significant ups and downs in this province in the last 40 years. The difference it makes to electricity consumption is not as much as you think either up or down. In other words, load tends to grow fairly steadily. So you have to be careful, I think, not to over-react to – you know, what is happening in the newspapers every day versus what will happen in what is sometimes called the "real economy". You're right about what you just said about some of the resource industries. Some of them have suffered a great deal. And yet, you know, we are experiencing – have been experiencing load growth in other areas."*[8]
>
> *"The actions that we propose to take this year are necessary, whether those actions are to meet expected requirements or are contingency steps necessary to be in position to be prepared for surprises. A plan based on precise calculations would not be a resilient plan. We are talking about plans to meet domestic customer demand far into the future, and that future is sure to be different than we expect it, and we cannot afford to come up short. If through time it becomes apparent that some products can be delayed or have their scope reduced, so be it. Those are action that can be taken as appropriate. However, the reverse cannot happen. We won't be able to depend on resources that don't exist."*[9]

Despite this commentary, the amount of new supplies of electricity that BCH is expecting to purchase from IPPs and others including industrials and government entities in the next 10 years has been reduced from 4,900 GWh to 4,200 GWh. This represents about 7% of BCH's current load of about 60,000 GWh. The Government's greenhouse gas ("GHG") initiatives and those of other government's around the world are going to result in an increased use of carbon free electricity and a reduction in fossil fuel energy. BCH has taken almost no fuel switching into account in its Load Forecast. For example, according to the President of BCH:

[7] Exhibit B-4, BCH response to IPPBC IR 2.11.1
[8] Exhibit C-17-10, pages 371-372 as confirmed at TR, V4 pages 456 and 457
[9] Exhibit C-17-11, pages 634-635 as confirmed at TR, V4 pages 460 and 461

> *"Another open question is will there be fuel switching away from – or towards more electric cars or plug-in electric vehicles? We haven't reflected any of that, or much of that, in our current forecasts. But even with an economic recession, that kind of fuel switching could make a significant difference."*[10]

This is a significant oversight and the answer is not to wait until BCH prepares its next long term acquisition plan.

It is against this broad backdrop that the IPPBC sets out its positions in detail below.

2. Load Forecast

The IPPBC has concerns over the load forecasts being used for the load/resource balances in the 2008 LTAP. These concerns can be summarized in the following categories:

2.1. Summary of Load Forecast Concerns

2.1.1. The Pre-DSM Load Forecast

The potential double-counting of DSM savings. The methodology used in this Load Forecast is susceptible to the risk of double-counting the energy to be saved by future Demand Side Measures. The IPPBC's position is that this pre-demand side management ("DSM") forecast already includes some of the efficiency gains and energy savings that are then also attributed to future DSM programs.

The estimation of the impact of electricity price increases. This Load Forecast uses certain assumed short and long-term price elasticities to calculate the load reductions that will result from BCH's forecast of its future rate increases. According to the research studies cited by BCH's expert witness, the most probable short-term elasticity index is only half the value that BCH has chosen to use for its forecast. On the other hand, for long-term elasticity value, BCH has chosen to use a zero, in favour of attributing all future energy savings to DSM programs, thus driving down the apparent unit costs of those programs.

The omission of potential future load growth. The Load Forecast has included a detailed analysis of the pessimistic outlook for the forest industry, but does not include much of the potential for additional load from other sources, such as the rapidly expanding oil and gas industry, or from fuel switching for residential space heating or the adoption of plug-in electric vehicles.

2.1.2. The After-DSM Load Forecast

The After-DSM Load Forecast is simply derived from a combination of the Pre-DSM forecast and the estimated energy savings from the portfolio of DSM measures. IPPBC believes that a significant amount of efficiency gain and rate impact has already been incorporated into the Pre-DSM forecast, such that the incremental energy savings attributable to DSM programs needs to be significantly reduced in order to avoid the double-counting of those benefits. The IPPBC will address this concern further under the next section on Demand Side Measures.

2.2. Detailed Discussion of IPPBC's Load Forecast concerns

2.2.1. The Pre-DSM Load Forecast

The potential double-counting of DSM savings.

[10] Exhibit C-17-10, page 372 as confirmed at TR, V4, page 469

- **The potential for double-counting in the forecasting coefficients.** BCH's load growth forecast is mostly a "top down" approach to forecasting, in which energy consumption is statistically related to certain external drivers. Although IPPBC acknowledges that there are huge difficulties and uncertainties involved in forecasting the external drivers, the IPPBC's concerns in this section are focused on the difficulty of deriving the statistical relationships between the drivers and the consumption, such that the derived coefficients are free from the influence of DSM programs. The statistical relationship between the load and the drivers is established by analyzing historical data. However, that historical data already contains the imbedded impacts of the historical DSM programs that were underway before and during the period of the analysis.

  BCH describes the load forecasting methodology, referred to as the Statistically Adjusted End Use Models (SAE), in Appendix D of the Application.[11] This SAE model is used for both the Residential and the Commercial Forecast. The method calculates regression equations of the form:

$$USE = a + b \times XHeat + b \times XCool + b \times XOther + \varepsilon$$

  The coefficients in this equation are determined by the analysis of historical data which implicitly contains the impacts of DSM programs. Accordingly, the derived coefficients reflect the relationship between the drivers and the load in the presence of a strong and active DSM program.

  It then becomes very difficult to use those same coefficients to forecast what the future load will be in the absence of such DSM programs. It is also difficult to tell how much DSM impact may be present in the coefficients but there needs to be some healthy allowance for this risk. Simply adding another variable to the above equation, to account for the presence of a DSM program, may not provide any useful benefit because the entire historical period under analysis contained a similar level of DSM activity.

  BCH appears to be aware of this potential double-counting problem, since it says in Chapter 6 of the Application:[12]

> *"With DSM savings forming an increasing component of BC Hydro's plan to balance supply and demand, the tracking of how BC Hydro's load is responding to DSM programs will need to be closely monitored. A key issue will be the methodology used for integrating historical loads with increasing levels of DSM savings into BC Hydro's load forecasting research and analysis. The load growth models are mostly 'top down' approaches at forecasting, and the DSM savings are mostly 'bottom up' estimates. Until more work is done to draw precise linkages between these models, additional caution, over and above the quantitative portion of the risk framework, is warranted when using the results for planning purposes.*
>
> *The following will be addressed:*
>
> - *Analyzing historical inclusion of realized DSM savings and related changes in usage rates by isolating their impact in load regression analysis from historical factors such as strikes, weather, economic and technology trends;*
> - *Considering the benefits of better integrating aspects of DSM planning with load forecasting analysis through en-use/energy intensity forecasts; and*
> - *Developing early load forecast signposts to identify how DSM programs and new electricity use trends are being reflected in and overall impact on load growth. …"*

[11] Exhibit B-1, Appendix D, pages 69-73
[12] Exhibit B-1, LTAP Application, page 6-9

It was also clear from the testimony during the hearing, that BCH was aware of the potential problem and actively seeking solutions. In response to a question from the IPPBC, BCH replied:[13]

> *"Q: And how do we make sure that there's no double accounting for new DSM versus old DSM?*
> *A: That's one of the very significant issues we're looking to – into, in terms of future load forecasts, given that our DSM programs are rapidly expanding, and that the potential for double counting in the load forecasts increases as our DSM programs are admittedly much more aggressive than they have been in the past…*
> *So we are studying this effect in terms of – to what extent do past DSM savings affect our load forecast?*
> *A: … We don't have – we haven't developed specific answers for it at this point, but it's certainly on our radar that it's a potential area we need to solve. …*
> *A: Well, we don't know the precise answer, but we are studying it.*
> *A: I mean, it's not as though we haven't had experience. We've been… developing demand-side management for some time …It's just that with a substantial increase in demand-side management, … we're going to have to take it to another level and try to draw distinctions between what we've done in the past and how we're forecasting that in the future."*

The same problem of imbedded DSM is also acknowledged by Avista Corp. in its 2007 Electric IRP.[14]

> *"The impact of conservation on electrical usage is fully imbedded in the historical data; therefore, we concluded that existing conservation levels… are imbedded in the forecast. Where conservation acquisition decreases from this level, retail load obligations would increase."*

In its Information Requests ("IR" or "Information Request"), the IPPBC asked for an understanding of how the imbedded DSM effects could be eliminated from the Load Forecast:[15]

> *"Since the coefficients in these equations are determined by the regression of historical data, how does BC Hydro eliminate the effects of historical DSM programs and rate increases which are implicitly <u>included</u> in the historical data, in order to produce a model which can predict the future load <u>excluding</u> the impact of any new DSM programs or rate increases?"*

BCH's short response did not offer a very helpful answer to this question, but instead implied that the question was either out of scope or had little merit, apparently because the methodology had been previously vetted and approved by the Commission:

> *"… The BCUC's 2006 IEP/LTAP Decision determined that BC Hydro's forecast methodology and its results are reasonable."*

In fact, the SAE methodology was apparently adopted after the 2006 LTAP[16], and so the BCUC Decision in that proceeding should not be taken as tacit approval of the methodology. At any rate, the BCUC asked the following question in an IR:[17]

[13] 2008 LTAP Transcript Volume 6, Page 1005-1006
[14] Exhibit B-3, BCUC IR 1.148.1, Attachment 1, page 2 of 8
[15] Exhibit B-3, IPPBC IR 1.5.1
[16] Exhibit B-3, BCOAPO IR 1.4.1
[17] Exhibit B-4, BCUC IR 2.181.1

> *"By using a regression equation based on historical data in load forecasting where load was influenced by DSM programs, is BC Hydro implicitly assuming that the same level of DSM effort will persist in the future?"*

Unfortunately, BCH may have misinterpreted this question in giving its very simple response, which was also not helpful in clarifying this issue:

> *"BC Hydro does not assume a constant level of DSM effort or savings in developing its load forecasts."*

The IPPBC suggests that methodologies may need to change and adapt as conditions change, and this also seems to be the view of BCH as set out in the extract above, particularly since it indicates that the future heavy emphasis on DSM will make this an even more critical issue.

- **Other indications of potential double-counting of DSM energy savings.**

There are also other indications presented in the evidence that suggest a significant potential for the double-counting of DSM savings. These are in the form of efficiency savings that appear to be already built into the Pre-DSM Load Forecast. The higher the level of natural efficiency gains that are being included in the Pre-DSM forecast, the less achievable potential remains to be captured by program savings, and the higher is the risk that the forecast for DSM program savings is over-stated and will not be deliverable.

Residential use per account. In response to a BCUC IR[18], BCH gave a table of values for the weather-normalized residential use per account (in kWh/account). The historical values in the table are weather-normalized actual usage. The projected future values are said to bebefore DSM savings and without rate impacts.

The table shows that over 5 years of recent history, the usage per customer rose by 7.7% (from 10,255 kWh per account in F2001 to 11,041 kWh in F2006) – this increased usage is after any energy efficiency gains as a result of DSM programs. The average annual increase was 1.5%/year – during a period when BCH had a strong and active DSM program that apparently was always successful in meeting its targets.

By contrast, the same table projects that the customer use per account will grow by only 5.7% over the 10 years from F2008 to F2018 and then by only 3.6% over the following 10 years (10,998 kWh per account in F2008, 11,624 in F2018, and 12,042 in F2028). Those growth rates amount to 0.55%/year over the first 10 years, and 0.35%/year over the next 10 years. And these greatly reduced growth rates are supposedly in the absence of any DSM or rate impacts.

Accumulated over that 20 year period, these reduced residential use rates per account imply a projected efficiency savings of 19% relative to the consumption that would occur if the use per account continued to rise at 1.5% per year.

To put that implied savings in context, the 2007 Marbec Conservation Potential Review estimated the total "achievable" potential annual savings for the Residential Sector at between 10% and 14% by F2026.[19]

Marbec states that, for the Residential Sector:

> *"Electric energy savings from electrical efficiency improvements would provide between 3,173 and 2,295 GWh/yr of electricity savings by F2026 in, respectively, the Upper and Lower Achievable Potential scenarios, or about 14% and 10%, respectively, relative to the Reference Case."*

[18] Exhibit B-3, BCUC IR 1.16.1
[19] Exhibit B-1, Appendix K, Sub-Appendix L, 2007 Conservation Potential Review Summary Report, page 25

It is the IPPBC's position that if, historically, customer use is growing by 1.5%/year in the presence of a strong DSM program, then to expect the future growth rate to decline so dramatically, in the complete absence of any continued DSM program or rate impact, is either very optimistic or it is incorporating some of the efficiency savings that would otherwise probably be attributed to a very aggressive future DSM measures.

That is to say that future DSM programs may not be able to achieve their targeted energy savings because those savings have already been incorporated into the Pre-DSM forecast. Simply put, why should there be a new result when essentially the same tools are used again?

Industrial energy intensity. The IPPBC inquired as to why the Industrial Load, shown in Table 2-2 of the Evidentiary Update, is only expected to grow at 8.7% over the next 20 years.[20] In its response, BCH provided a table showing its forecast of industrial energy intensity, in GWh/million $ of real GDP, before the impact of DSM.

The table shows that the industrial energy intensity being used in the Pre-DSM Load Forecast, is expected to improve from 0.120 GWh/million $ in F2009 to 0.090 GWh/million $ in F2029. That is a 25% reduction in the energy used per real $ of output, which is a significant gain in efficiency for the industrial sector – and this improvement is expected to occur without any DSM stimulation.

To put this efficiency gain in context, the 2007 Marbec Conservation Potential Review projected the Industrial Sector energy purchases growing from 21,810 GWh in F2006 to 26,818 GWh in F2026. That's a 23% growth in 20 years, or 2.1% per year. Marbec then estimated that the "achievable" energy savings over that period could range from 2,895 GWh (11%) to 6,737 GWh per year (25%). Marbec states that:[21]

> *"Electric energy savings from electrical efficiency improvements would provide between 6,737 and 2,895 GWh/yr of electricity savings by F2026in, respectively, the Upper and Lower Achievable Potential scenarios, or about 25% and 11%, respectively, relative to the Reference Case."*

In that context, the 25% efficiency gain being incorporated into the Pre-DSM Load Forecast appears to be a significant proportion of the achievable potential. If this is truly possible, then IPPBC commends it as a very good thing, because it appears to be achieved without a great deal of spending on further DSM programs.

However, the program savings are still being targeted to be layered on top of this efficiency gain and the IPPBC submits that the further savings being targeted by programs is overly-optimistic and therefore at significant risk.

The IPPBC submits that, if that large an amount of efficiency gain can occur naturally, without any stimulation from DSM programs, then the further gains that are targeted to be achieved by DSM measures are probably over-stated, and should be significantly downsized, or they will have a very high risk of being under-delivered – not to mention a very high cost for the incremental energy savings that will actually be achieved.

That is to say, a good portion of the expected efficiency gains, and the associated energy savings, are already built into the Pre-DSM forecast. If this Pre-DSM forecast is true, then the projected further savings targeted from DSM measures is at risk of being significantly under-delivered. If such a high level of natural efficiency gains is being included in the Pre-DSM

[20] Exhibit B-10, Evidentiary Update, page 7, and Exhibit B-12, IPPBC IR 3.8.2
[21] Exhibit B-1, Appendix K, Sub-Appendix L, 2007 Conservation Potential Review Summary Report, page 36-37

Load Forecast, then care must be taken to avoid having those same energy savings included in the targets for DSM program savings.

IPPBC is concerned that this represents a serious double-counting of the potential energy savings. The consequence of any double-counting between the Pre-DSM forecast and the targeted DSM savings, would be that either the Pre-DSM load forecast is too low, and should be raised, or the forecast of DSM program savings is too high, and should be lowered. At any rate, with the combination of the two forecasts, there is a high risk of counting the same energy savings twice.

The long history of DSM in British Columbia. Through cross examination,[22] the IPPBC highlighted the fact that BCH has been actively promoting DSM programs for 36 years i.e. since 1973.[23] BCH is proposing to carry on with similar programs over the next two decades.

BCH's Annual Reports for 1981 and 1982 indicated that all of the following programs were active 28 years ago:

- Consumer education seminars
- Low cost financing programs for insulation and multi-glazing
- Aerial thermography to detect heat loss
- A trial of a household Energy Cost Indicator (like a smart metre)
- The Save Energy Save Money advisory program
- Lighting audits
- Advisory services and analyses to instruct in loss reduction in major industrial processes and in public and commercial buildings
- Introduction of new recommended standards for efficient use of energy in homes
- Information about energy conservation is communicated through newspapers, magazines and television as well as displays at trade show and shopping malls
- Institution of the Energuide label
- Provision of materials and support for in the school teaching of energy conservation

Twenty-one years ago, BCH's Annual Report for 1988 stated that[24]:

> *"… we have launched the Power Smart conservation program. This 10-year, $225 million energy efficiency initiative is expected to free up 2.4 billion kilowatt hours of electricity by 1998,…"*

BCH has been among the most active proponents of DSM in the North American electricity industry - trying to change consumer behaviour since the 1970s. Yet the DSM implementation plan in Appendix K of the LTAP describes the Residential Behaviour Program as follows:[25]

> ***"Objective –*** *The program objective is to inform and educate residential customers about how much electricity they consume and motivate them to reduce that consumption through behavioural changes.*
> ***Barriers – Awareness*** *– Although customers receive bi-monthly bills, most are not aware of how much electricity they consume or whether their consumption level places them in the high-use or low-use bracket for their dwelling type."*

And with regard to industrial customers, a similar statement is made:[26]

[22] 2008 LTAP Transcript, Volume 12, page 2223-2245
[23] Exhibit C17-22, page 3, BC Hydro Annual Reports 1981/82 through 1985/86
[24] Exhibit C17-23, page 4, BC Hydro Annual Report 1988
[25] Exhibit B-1, Appendix K, page 138 of 213, the Residential Behaviour Program

> ***Barriers – Awareness*** *– Many industrial customers are unaware of energy management practices and their benefits.*

If BCH's programs have been active and successful for 30 years, then its customers should be be very aware of the benefits of energy conservation. However, the recent usage per consumer account has increased at the highest rate since 1990. In the 11 years from F1990 to F2001, the Use Rate increased by only 1% in total. Then, in the 5 years from 2001 to 2006 despite increased DSM program spending, it increased by 7.7%[27], in spite of the most intense and aggressive DSM program spending in BCH's history.

Is recent experience telling us that some of these programs may have run their course, and have reaped all the easy benefits that are available? On one hand there is talk that we have established a "conservation culture" while on the other hand, the public's appetite for energy appears unabated, in fact increasing. This may mean that in the future, we will have increasing difficulty getting new, incremental, net benefits out of the same old light bulb, appliance, insulation and education programs. Only time will tell, but the risk of under-achievement is clear and significant.

- **Elasticity -- the estimation of the impact of electricity price increases.** BCH generally follows a traditional method of adjusting consumption for the impact of price changes by using a measure called elasticity. Elasticity can be either short-term, measuring the impact on consumption in a one-year time frame, or long-term, measuring impacts over multiple years.

  Short-term elasticity. For the Load Forecast, BCH has adopted a short-term elasticity of -0.1, which is the % by which demand is expected to fall in the first year following a price increase of 1%.

  This is summed up by BCH's witness:[28]

  > *A: …"the same assumptions on elasticity have been used for the commercial class and the residential class. And minus .1 is used for a total rate elasticity. Minus .05 is used for a rate level elasticity, and the difference between the total elasticity and the rate level elasticity is the rate design effect."*

  The evidence, supporting the -0.1 total elasticity value, is given in Appendix E of the LTAP Application. The witness reviewed over 100 published studies but narrowed his review to jurisdictions with relatively low rates and winter peaking systems.

  For his residential elasticity estimate, the witness, Dr. Orans cites 4 studies which showed a price elasticity range from 0.0 to -0.28. He states that:[29]

  > *"…these four studies suggest that a price elasticity estimate of -0.1 is a conservative but plausible assumption used to quantify the residential consumption response to a new inclining block tariff that embodies an average rate change."*

  However, on closer scrutiny of these 4 studies, it appears that 3 out of the 4 studies show a range of only 0.0 to -0.079. Only the 4th study shows a higher value, and it is a 30 year old study done over a period of only 1 year in 1977-78. Given these study results, a value of -0.1 should be characterized as aggressive, rather than conservative. The IPPBC suggests that a short-term elasticity value of -.05 would be more appropriate, given the study results being cited.

[26] Exhibit B-1, Appendix K, page 181 of 213
[27] Exhibit B-3, BCUC IR 1.16.1
[28] 2008 LTAP Transcript, Volume 10, page 1696
[29] Exhibit B-1, Appendix E, page 16 of 28 and Table 2 on page 17 of 28

For his Non-Residential elasticity estimate, Dr. Orans cites 4 additional studies which showed a range of values from 0.0 to -0.142.[30] However, again on closer scrutiny, it appears that 3 out of 4 of these studies showed a range of 0.0 to -0.09, and all of these studies were evaluating time of use situations, in which customers could switch their consumption for heavy load or on-peak hours to other hours to achieve a price saving. That type of study puts a different meaning on elasticity, since customers do not have to reduce their consumption but merely shift it to another time period.

As a final test, Dr. Orans compared the proposed value of -0.1 to that used by two Pacific Northwest utilities in their 2007 IRPs.[31] Of these, PacifiCorp appears to have done the most thorough job of econometric modeling and arrived at a value of -0.05 for the residential sector elasticity. An excerpt from the PacifiCorp IRP is included as an IR attachment, describes its process as follows:[32]

> *"An econometric equation with usage per customer as the dependent variable and the real price of electricity, real household income, cooling degree days, heating degree days, real natural gas prices, and lagged use per customer as independent variables was developed. The time period of estimation was from 1982 through 2005. The results of this estimation indicate that the short-term price elasticity was -0.05 and that the long-term price elasticity was -0.09. Using either measure, it was determined that electricity is price inelastic,…"*

Dr. Orans also states that PacifiCorp used a non-residential elasticity of -0.1, and this was based on the U.S. DoE's 2006 Demand Response Report, an excerpt of which is also included as an attachment to the same IR.[33] The DoE report states that the value of -0.1 is derived from the average of 5 day-ahead RTP studies of commercial and industrial customers and the details of these are given in Appendix C, which has been provided as an IPPBC exhibit.[34] On examination, those 5 C&I studies show values ranging from -0.01 to -0.28.

However, on closer scrutiny, 2 of the 5 studies are quoting values for the elasticity of substitution, which is not appropriate. A third study is from Georgia Power, a southern utility, where the price levels ranged from $0.15 to $1.00/kWh, again not appropriate for comparison to the BCH situation. The fourth study was from Duke Power in Carolina and is also apparently a study of time shifting behaviour, since the detailed commentary states:[35]

> *"… high prices in one hour result in reduced usage in that hour as well as in adjacent hours… Usage in many other hours of the day was found to be a substitute to the afternoon hours"*

Which leaves only the fifth study from the U.K., Midlands Electric, which showed elasticities ranging from -0.01 to -0.27. However, the commentary relating to that study states:

> *"Customers in the water supply industry were the most price-responsive, with a maximum hourly own-price elasticity of -0.27, while all of the other industrial classifications in the participant population exhibited price elasticities of less than -0.05 in all hours."*

The IPPBC submits that all of Dr. Orans evidence indicates the short-term price response for electricity in a low-priced winter-peaking system like B. C. will be quite inelastic, and a value of -

[30] Exhibit B-1, Appendix E, Table 3 on page 20 of 28
[31] Exhibit B-1, Appendix E, Table 4 on page 21 of 28
[32] Exhibit B-3, BCUC IR 1.148.1, Attachment 1, page 4 of 8
[33] Exhibit B-3, BCUC IR 1.148.1, Attachment 1, page 8 of 8
[34] Exhibit C17-21, Appendix C, Intensity of Customer Demand Response
[35] Exhibit C17-21, page 89 (5 of 8)

0.05 should be the most probable estimate for short-term elasticity. This value is only half the value that BCH has used in its forecast, which is a further indication that the Pre-DSM Load Forecast has been slightly depressed by the forecasting methodology.

Long-term elasticity. Long-term elasticities are likely to be much more significant than short-term. However, BCH has elected to use a value of zero for long-term elasticity, and the reason is quite straightforward – it's the simplest approach. The problem with long-term price response is that its impact is far too closely intertwined with the impacts of the coincident DSM programs to be easily separated.

Dr. Orans described this difficulty during questioning:[36]

> *A: " If you look at the long-run studies that are in the literature, …what you've got in there is a lot of State jurisdictions imposing new codes and standards during that period, and so you have a price effect. They have a short-run price effect that's relatively moderate, and they have a long-run that picks up all the codes and standards and all the programs that the jurisdiction has implemented. …But there is no way most of these people doing these studies can pick up all the individual utility programs that happen and all the codes and standards.*
>
> *So they call it long-run price elasticity effect. It's got commingled in it, codes and standards, DSM programs and long-term pricing.*
>
> *…And when Mr. Ince and Mr. Hobson and I all met on this, … we looked at the detailed programs Mr. Hobson had, and the forecasting Mr. Ince was doing, it looked most clear, the most clear way to do this rather than try to peel apart those commingled things, was to – and we don't have what we call a pure short-run price elasticity either. The elasticities that I'm using sort of represent behavioural changes that would be plausible within one year."*

That is to say that if they were to use the long-term elasticity in forecasting the Pre-DSM load, and also attribute the full expected energy savings to the DSM programs, it would be effectively double-counting the energy savings. To avoid this double-counting, the long-term elasticity value was set to zero, to allow for all of the energy savings to be credited to the programs. This was much easier to do than to try to adjust downward each of the program savings in order to allow for the imbedded impact of the rate increases. Dr. Orans further clarifies this as follows:[37]

> *Q: …"what is the long-run price elasticity that you see from the LTAP?…"*
> *A: "I can't give you an estimate of what the long-run piece would be. I mean, you could do a calculation of the end result and try to attempt to say which is rate-induced and which is really program-induced. But there really – in the way we're estimating total amounts of conservation, we don't really need to calculate the long-run piece because it's captured already in the program data and the codes and standard data."*

And he makes it clear in response to another question that the choice of how to do this was one of expediency:[38]

> *A: …"we had really two choices. We could use a long-run price elasticity and then strip out everything out of the codes and standards and program data, which seemed to me a much harder task, than using the short-run elasticity data that we had had from other studies.* ***So we excluded the long-run elasticity data****."*

In addition:[39]

[36] 2008 LTAP Transcript, Volume 10, page 1705-6
[37] 2008 LTAP Transcript, Volume 10, page 1854-5
[38] 2008 LTAP Transcript, Volume 11, page 1912

> *A: "Well, once again we didn't seek to – there were two paths, and – other than reduce Mr. Hobson's estimates, the program data which was an extensive, huge data set and we didn't see an easy path through that, that maze of all of the program data, we used what we believe are reasonable short-run estimates of price elasticities, not long-run."*

Another BCH witness also sums it up very succinctly in this response to Mr. Fulton:[40]

> *A: "…long-term elasticities are multiples of the short-term, but hopefully in BC Hydro's DSM plans we've captured a lot of that incremental benefit, elasticity benefit, through our DSM programs."*

Higher prices will increase the conservation incentives for any given DSM program but it's not easy to determine the exact amount of energy savings that should be attributed to the program and how much should be attributed to the price response. For example, people will be much more willing to invest in window replacements or insulation if they can foresee a larger savings in electricity or gas bills.

Although the motivation to reduce the amount of workload seems commendable, the result has unfortunate consequences. The problem this creates is that it masks the true cost effectiveness of the DSM programs. When the programs are evaluated individually, they appear to be tremendously cost-effective because they've been credited with all the savings that result from the customer response to the rate increases. In fact, without the rate increases, the programs by themselves would show significantly lower energy savings and would look much less attractive.

But the dilemma is, without going back and adjusting the savings from every individual program to remove the price impact effect, how can we estimate what is the proper amount that should have been attributed to the price elasticity impact of the forecast rate increases?

The IPPBC submits that the BCUC was on the right track when it asked for the analysis in BCUC IR 2.230.1.[41] That analysis showed that a long-term elasticity value of -0.15 would produce an energy savings of approximately 3,500 GWh/yr by 2016 and 4,500 by 2020 (assuming an extra 10% to allow for losses).

This could amount to 35% to 45% of the total savings for the entire DSM Option A portfolio. That's a tremendous amount of extra credit that's being implicitly attributed to the program segment of the portfolio.

It is necessary to remove this amount of energy savings from the targeted program savings, in order to correct for this double-counting. However, IPPBC suggests that it is not necessary to make a correction to the Pre-DSM Load Forecast because that forecast has already been adjusted downward by the inclusion of the significant energy efficiency savings imbedded in the Residential use rate and the Industrial efficiency, as previously identified.

Much of the extra savings that should have been attributed to the rate increases, has already been built into the Pre-DSM forecast. There is in excess of 5,000 GWh/year of energy efficiency savings already imbedded in those two components of the Pre-DSM forecast and this can stand as a proxy for the missing impact of long-term elasticity.

- **The omission of potential future load growth.** The Load Forecast has included a detailed analysis of the pessimistic outlook for the forest industry, but does not include much of the potential for additional load from other sources, such as the rapidly expanding oil and gas industry, or from fuel switching for residential space heating or the adoption of plug-in electric vehicles.

[39] 2008 LTAP Transcript, Volume 11, page 1931
[40] 2008 LTAP Transcript, Volume 11, page 1923
[41] Exhibit B-4, BCUC IR 2.230.1

BCH has taken the approach that these additional loads are not sufficiently certain or definitive enough to be included in the base case forecast as *"credible electrification scenarios."*[42] On the other hand, they have chosen to include zero values for these additional loads when zero values are even less credible than educated estimates would have been. The IPPBC suggests that best estimates would be more appropriate for the base case forecast then assuming zero values.

The following potential new loads are notably conspicuous for their absence from the base load forecast:

Electric plug-in hybrid vehicles.

The base load forecast does not include 1 kWh for the potential load from these electric vehicles. On February 20, 2009, day 2 of the LTAP hearing, a witness for BCH responded to a question from the IPPBC as follows:[43]

> *"A: ...we cannot build things into our load forecasts based on anecdotal evidence. There's got to be evidence there supporting why the load is growing over a 20-year period. And right now we have a lot of anecdotal evidence about electric plug-in vehicles. We don't see the infrastructure there. We don't think that there are certain expected loads at this point in time."*

On March 9, 2009, BCH issued a press release stating:

> *"Major auto manufacturers have announced plans to introduce electric models in the coming year, and early forecasts suggest anywhere from 10 to 60% of new vehicles purchased by 2025 will be electric vehicles.*

After a competitive call for proposals, BCH has contracted Electric Transportation Engineering Corporation (eTec), a subsidiary of ECOtality, to detail the necessary actions for deploying electric vehicle charging infrastructure.

> *'This will allow BC Hydro to anticipate the potential introduction of clean electric vehicles throughout B.C.,' said Bob Elton, BC Hydro President and CEO. 'By proactively determining the appropriate guidelines for electric vehicles charging infrastructure, BC Hydro is streamlining the process for consumer adoption of clean electric vehicles.'"*

BCH has estimated that if all 2.7 million passenger vehicles in B.C. were replaced by electric vehicles, the impact on BCH' load could be approximately 9,000 GWh per year.[44] Therefore a 60% penetration could add up to approximately 5,000 GWh of new load by 2026. The IPPBC suggests that some trend is obvious enough for a reasonable best estimate to be included in the base load forecast – at least 10-15% penetration by 2026. As noted in BCH's response to IPPBC IR 2.4.3 the Energy Consumption Equivalent (kWh/km) an electric car is very efficient as compare to fossil fuel driven cars. This efficiency translates into operating cost savings which are in addition to GHG savings.

Fuel switching for residential space and water heating.

In the Load Forecast, BCH assumes that approximately 20% of accounts will use electric space heating and 35% will use electric water heating,[45] which is essentially the same as the existing stock. However, it has also estimated that if all residential buildings in 2020 were to adopt electric space and water heating, there could be an additional 26,000 GWh of new load.

[42] Exhibit B-10, the December 22, 2008 Evidentiary Update, page 11
[43] 2008 LTAP Transcript, Volume 4, page 473-4
[44] Exhibit B-10, the December 22, 2008 Evidentiary Update, page 11
[45] Exhibit B-10, the December 22, 2008 Evidentiary Update, page 11

Mr. Jesperson, the CEO of Terasen Gas, made the following comments in a speech delivered to the Board of Trade in November, 2008:

> *"We observe that the [BC Hydro] demand forecast does not include the impact of plug-in vehicles, electrification of Ports and assumes historic levels of space heating load capture of some 20% market share. As to the latter, as new housing stock in B.C. has increasingly moved to multifamily dwellings and gas prices have escalated in absolute terms, as well as relative to artificially priced electricity, natural gas' capture of market share has declined. Further, we have been advised that it is the view of the largest property developers in the lower mainland that natural gas capture for space heating applications in future multifamily developments is about 20%. That's 20% gas and 80% electric, not the other way around [as is being assumed by BC Hydro]"*

As part of the Conservation Potential Review, BCH conducted an extensive analysis of the potential for residential fuel switching from electricity to gas for space heating, cooking, and clothes drying. However, the analysis stopped abruptly when it found there was no potential to pursue this switching as a DSM alternative; no analysis was performed to show the potential for fuel switching in the reverse direction.

According to Exhibit 9.1,[46] the analysis showed that there appears to be no achievable DSM potential, even at an assumed wholesale gas price of $6.11/GJ ($22/MWh / 3.6GJ/MWh = $6.11/GJ). The reason appears to be that, even at this relatively low wholesale gas price, the consumer prices for gas and electricity provide no economic incentive to switch from electricity to gas. On the following page, the CPR report states that:

> *"… there would need first to be a mechanism… that permanently closed the retail price gap between natural gas and electricity."*

Apparently, the economic incentive for consumers is operating in the reverse direction, in favour of switching from gas to electricity, particularly since the gas price used for the CPR analysis was only $6.11/GJ, compared to prices in the range of $9-12/GJ, being forecast by BCH in the LTAP, and particularly since future gas consumption will likely also entail a GHG compliance cost upwards of $30 per tonne of CO_2, making clean, green, renewable electricity the fuel of economic choice for residential and commercial consumers in the future.

BCH appears to have simply stopped pursuing the matter once the CPR showed there was not potential for fuel switching from electricity to gas. The IPPBC suggests that it would be prudent for BCH to complete the reverse analysis and discover what the potential is for fuel switching in the opposite direction. If Mr. Jesperson's comments are accurate, then BCH should be providing for a significant amount of new load from residential and commercial space and water heating over the next 20 years. It appears that new construction will be heavily weighted towards electric heating, and it may be that retrofitting of some of the existing housing stock will also be pursued. Or BCH's customers will plug in electric heaters to meet some of their heating requirements – the "hardware heater hybrid".

New loads in the oil and gas industry.

In the Report from the B.C. climate Action Team, recommendation 17 states:

> *"Introduce policies and regulations to promote electrification in new oil and gas developments."*

Although this recommendation is not in the form of binding legislation, given the huge size and consistent growth of this key industry, BCH should be at least planning for the new load that

[46] Exhibit B-1, Appendix K, Sub-Appendix L, 2007 Conservation Potential Review, page 54 of 58

could result from continued expansion. The Dawson Creek area, within the integrated system, is indicating very rapid growth and the non-integrated Fort Nelson area is showing tremendous new growth in oil and gas production.

BCH is presently proposing a stop-gap solution in the form of a new thermal generator to deal with the Fort Nelson area. This new capacity will very soon be exceeded. The only long-term solution to the growth will come from adding a transmission connection to Fort Nelson and reinforcing the lines to Dawson Creek. Accordingly, these new loads should be added to the base case forecast for the integrated system.

2.3. Fort Nelson and the Demand for Electricity by the Oil and Gas Industry

The IPPBC agrees with BCH that it requires additional amounts of electricity for its customers in the Fort Nelson. Currently this area is not directly connected by way of the British Columbia Transmission Corporation's to BCH's system. There is an indirect connection by way of Rainbow Lake, Alberta but it would need a very substantial upgrade to meet the increasing Fort Nelson requirements which are being driven by the discovery of unconventional natural gas reserves in shale formations known as Horn River Basin and Cordova Embayment.

Pursuant to section 44.2(3)(a) of the Utilities Commission Act BCH is seeking a determination that the following expenditures are in the public interest in relation to increasing its generation facilities in Fort Nelson:

> *" ● Expenditures of $140.1 million in F2009-F2012 required to complete the Definition phase work for and implement, the Fort Nelson Generating Station Upgrade Case 3.2*
>
> *In the alternative, BC Hydro seeks to a determination that expenditures of $94.5 million to complete the Definition phase work for, and implement, the Fort Nelson Generating Station Upgrade Case 2 are in the public interest under subsection 44.2(3)(a) of the Act."*

The magnitude of the projected increase in BCH's load in the Fort Nelson area is critical to the determination. But so is the magnitude of its GHGs because the projected load increase will be driven by natural gas production which is not immune from the provisions of the Greenhouse Gas Reduction Targets Act which says in part:

> *"2 (1) The following targets are established for the purpose of reducing BC greenhouse gas emissions;*
> *(a) by 2020 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 33% less than the level of those emissions in 2007;*
> *(b) by 2050 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 80% less than the level of those emissions in 2007*
> *(2) By December 31, 2008, the minister must, by order, establish BC greenhouse gas emissions targets for 2012 and 2016…"*

Or to barriers in the U.S. export markets with respect to GHG's incurred in the production and transportation of natural gas in B.C..

If gas producers install self-generation they will have to recover their capital and operating costs and pay the carbon bill. The IPPBC expects that this "all in" cost as compared to the cost of purchasing renewable electricity from BCH under its approved tariff will be considerably higher but there is nothing in the Application that indicates that BCH has done this calculation. It will be instrumental in determining the

electricity requirements of the oil and natural gas industry in the Fort Nelson and Peace River areas of B.C.

The lack of this calculation indicates that BCH has paid little attention to B.C.'s rapidly expanding oil and natural gas sector, and is further evidenced by BCH response to the IPPBC Information Request set out below. While there has been an improvement over previous efforts, it is nowhere near the attention that has been paid to B.C.'s apparently declining forestry industry[47]:

> *"Other than the material set out in Attachment 3 to the BC Hydro 2008 LTAP Evidentiary Update, please provide the details of any discussions or exchanges of material between the Canadian Association of Petroleum Producers or similar organizations, individual oil and gas producers and the B.C. Oil and Gas Commission with respect to the production of oil and natural gas in B.C. and any corresponding demand for electrical energy and capacity for this production including without limitation the oil and gas pipeline sector and in the Dawson Creek area of B.C."*
>
> *RESPONSE:*
>
> *"BC Hydro began participating in a working group with respect to the oil and gas sector load requirements in January 2009. For further details refer to the response to BCUC IR 3.275.1 and BCOAPO IR 3.7.1. Prior to this, discussions on load requirements had been ongoing between Key Account managers and potential new customers requesting electrical service. Since these discussions are customer specific they are not provided in this response."*

On cross examination a representative of BCH also said*:*

> *"A: Well, we did a very rigorous forecast of oil and gas loads this year. We spent a lot of resources on it, including consulting reports from Pyra and Zip Energy Group out of Calgary. We did estimates of the potential of reserves in the area, expected number of wells drilled, what the production rates of those wells are going to be, the electric potential of those wells in terms of how much compression requirements there were, so for example what were the initial pressures coming out of the wells, what were the ultimate discharge pressures coming out into the gas plants in the region, and then we did compression calculations in terms of how much energy was required in order to move that gas. And that all rolled up into the forecast that you see here."*

Setting the wheels in motion to establish a working group with the oil and gas sector in 2009 is laudable but the results were not reflected in the 2008 Load Forecast. An examination of the material that BCH has provided on the projected demand for this sector, some of which was put to BCH on cross examination[48] leads to a confusing outcome as set out in the following table:

[47]Exhibit B-12, BCH response to IPPBC Information Request 3.3.5
[48] TR, V6, pages 969 to 983

Year	2008 Annual Production Reference Forecast Fort Nelson Area (Bcf)[49]	2008 Annual Total Reference Oil and Gas Load Forecast Fort Nelson Area (GWh)	CAPP Annual Horn River Basin Production Forecast (Bcf)	CAPP Annual Horn River High Case Load (GWh)[50]	CAPP Annual Horn River Low Case Load (GWh)	2008 Annual Production Reference Forecast Integrated Area (Bcf)	2008 Annual Total Reference Oil and Gas Load Forecast Integrated Area (GWh)
2010	6	145	0	0	0	62	654
2020	346	744	985	2,760	788	368	1,035
2025	426	1,001	n.a.	n.a.		293	1,001

The figures in the above table do not include any of the non-oil and gas load in the Fort Nelson area. The Horn River figures do not appear to include the existing Spectra Fort Nelson facility. The map shown in Exhibit B-10, Attachment 3, page 6 of 10 does not appear to include the Cordova Embayment which the IPPBC understands is another large unconventional shale gas formation immediately to the east of the Horn River basin.

To put the forecast natural gas production figures into perspective, the daily throughput of the MacKenzie Valley Pipeline would be approximately 1.2 – 1.9 Bcf per day[51]. According to BCH, the daily output from the Fort Nelson area in 2020 will be about 1 Bcf per day and the Canadian Association of Petroleum Producers ("CAPP") forecast about 2.7 Bcf per day.

Even a tertiary review of the figures indicates major inconsistencies in a number of areas including the ratios of electricity to natural gas production. Perhaps some of the inconsistencies can be accounted for by the following statement[52]:

> *"The range of electric load potential of some 100 – 350 MW is summarized in Table 1 below. It results from assumptions concerning the timing of electrification. The conclusion is that the earlier power can be brought to the area, the higher the load potential, thereby providing the largest benefit from a GHG mitigation perspective."*

But there are others such as the difference between the Horn River forecasts as supplied by CAPP and BCH's in terms of annual natural gas production and electricity requirements that require a lot of additional work. In 2020, the CAPP forecasts natural gas production at 985 Bcf annually and BCH 346 Bcf. The CAPP low case electricity load forecast is 788 GWh and the BCH reference case is 744 GWh. In the Integrated Area, natural gas production in 2020 will be about the same as the BCH forecast for Fort Nelson but electricity demand in the Integrated Area will be about 300 GWh higher or approximately 33% higher. Why the difference?

[49] Fort Nelson and Integrated Areas figures are from Exhibit B-10, BCH response to BCUC Information Request 3.248
[50] Horn River figures are from Exhibit B-10, Attachment 3, page 10 of 2. The 2.7 bcf/d figure was converted to an annual figure on the basis of a 365 day year. No production was assumed in 2010. The 100-350 MW figures were converted to annual GWh on the basis of a load capacity factor of 90%. In a response to a JIESC IR, BCH used a capacity factor of 70% which does not appear to be realistic in relation to the daily volumes of gas expected to be processed.
[51] Exhibit C 17-6, IPPBC response to BCH Information Request 8.2
[52] Exhibit B-10, Attachment 3, page 4 of 10

The IPPBC respectfully submits that BCH's forecast of the electricity requirements from oil and gas development in the Fort Nelson is inadequate. It takes the same position in relation to the oil and gas forecast for the Integrated Area. The customer contact and base information about the industry has not been compiled as BCH has waited for potential service requests to materialize. IPPBC suggests that a more proactive approach would have provided better results. BCH did not have any discussions with the B.C. Oil and Gas Commission that is located in Fort St. John[53]. This should be one of the starting points for an in depth analysis of the electricity requirements of the B.C. oil and natural gas industry.

2.4. Fort Nelson

There is at least one industry in B.C. that recognizes the benefits of fuel switching from a GHG perspective if the switch is to renewable electricity. Given BCH's low rates, there also may be significant financial benefits as compared to self-generation. The GHG benefits will be severely reduced unless BCH can deliver electricity as soon as possible to the oil and gas industry. Otherwise it may have no other option but to develop its own natural gas fired self-generation for processing, carbon sequestration and compression.

If BCH builds more natural gas fired generation in Fort Nelson, this generation is not going to help the oil and gas industry reduce its GHG emissions or B.C meet its 2020 legislated target of a 33% reduction from 2007 by 2020[54] . Conversely if BCH doesn't move quickly to provide electricity to the Horn River area, industry will build its own natural gas fired self-generation. Some of BCH's customers might not support this idea in order to preserve their own low electricity rates from heritage hydro generation. However, this won't be the answer to Provincial GHG reduction and economic growth.

There is every indication that the answer is a new transmission line from the G.M. Shrum switchyard to Fort Nelson which would link it to the BCH and BCTC integrated systems and in particular the 2700 MW G.M. Shrum and 600 MW Peace Canyon generating stations. They are much closer to Fort Nelson than any major generating stations in Alberta, thus minimizing the associated problems of long radial lines.

The IPPBC expects that the prospects for this line will be reviewed as part of the Section 5 Inquiry with any decision not expected until at least autumn of 2010. In the meantime load in the Fort Nelson area, including Horn River, needs to be served by BCH.

Because of the need to reduce GHGs together with the price risk, natural gas price risk and competitively priced new B.C. renewable generation, it is the IPPBC's position that BCH should minimize its medium and long term investment in natural gas fired generation. The IPPBC reluctantly supports Fort Nelson Generating Station Upgrade 3 at a price of $140.1 million even though the request for BCUC approval should have been advanced as an application for a certificate of public convenience and necessity and have received advance approval from BCH's Board of Directors. In this instance it is a matter of urgent need.. To supply and retain the additional load that needs to be served until the transmission line is completed, BCH should use temporary natural gas fired generation.

2.4.1. The After-DSM Load Forecast

The After-DSM Load Forecast is simply derived from a combination of the Pre-DSM forecast and the estimated energy savings from the portfolio of DSM measures. The IPPBC believes that such a

[53] TR, V6, page 979
[54] Section 2, Greenhouse Gas Reduction Targets Act

significant amount of efficiency gain and rate impact has already been incorporated into the Pre-DSM forecast, that the incremental energy savings attributable to DSM programs needs to be significantly reduced in order to avoid the double-counting of those benefits. The IPPBC will address this concern further under the next heading, Demand Side Measures.

3. Demand Side Measures

The government gave the following specific direction in the 2007 B.C. Energy Plan:[55]

> *"Under this Energy Plan, utilities in BC are to pursue all cost-effective investments in demand side management. Cost-effective demand-side investments are those that are equal to or lower in cost than supply side resources."*

The IPPBC is very much in favour of energy efficiency and conservation. However, IPPBC notes that a key phrase in the government's policy statement is the term "cost-effective", and therein lays the complexity. Demand-side measures are not easy to evaluate as far as their true cost-effectiveness is concerned.

When a supply-side project is proposed to BCH by an IPP, the price is agreed for the duration of the contract, and BCH will only pay for energy that the project actually delivers. This is not the case, however, for demand-side measures. The costs and the expected energy savings are estimated to the best abilities of the program designers, but generally the investments are made up front and if the energy savings fail to materialize, there is no refund of the investment.

In reality, it's very difficult even to measure how much savings are actually achieved, either before or after the fact. The estimates of the savings rely heavily on some critical assumptions about what would have prevailed in the absence of the DSM measures.

BCH has chosen to present its DSM proposal as a total portfolio, consisting of rate measures, program measures and codes and standards. The original overall unit cost for all of the measures in the portfolio was a very attractive $41/MWh. However, the IPPBC wishes to point out that very low figure results from averaging some more expensive programs with some measures that have very little cost, such as the demand reductions due to rate increases.

The following table illustrates how the DSM Option A portfolio was broken down in terms of the forecast energy savings by the end of a 20 year period to 2028:[56]

[55] Exhibit B-1, Appendix B1, the 2007 BC Energy Plan, page 46 of 84
[56] Exhibit B-3-3, derived from the response to JIESC IR 1.17.1

Cumulative Energy Savings F2008-F2028 (GWh/yr)

	Codes & Standards	Rate Structures	Programs	TOTAL
Residential	3,870	1,220	1,273	6,363
Commercial	682	496	2,160	3,338
Industrial	209	825	2,403	3,437
TOTAL	4,761	2,541	5,836	13,138
	36%	19%	44%	100%

Clearly there is a great deal of benefit being derived from governmental changes to building construction codes and product standards, as well as from the consumer response to increasing electricity prices. DSM programs per se are only responsible for 44% of the total energy savings at the end of the 20 year period – and, as we have shown in the previous discussion, the savings from the long-term price elasticity have been incorporated within the Program savings shown above, rather than under Rate Structures.

When the Total Resource Costs of the total portfolio (also known as the All Ratepayers Costs) are also examined, it can be seen that the DSM Programs are actually responsible for the lion's share of the total costs, namely 71%, as shown in the following table:[57]

All Ratepayers Costs F2008-F2028 ($ millions)

	Codes & Standards	Rate Structures	Programs	TOTAL
Residential	1,840	34	1,234	3,108
Commercial	325	23	1,815	2,162
Industrial	36	192	2,242	2,470
Portfolio-Level			749	749
TOTAL	2,201	249	6,040	8,489
	26%	3%	71%	100%

Clearly all the DSM components in this portfolio do not show the same degree of cost-effectiveness. Rate structures are very inexpensive, Codes and Standards are the next least costly, and Programs, as a group, are the most costly per unit of energy saved.

When BCH issued its Evidentiary Update on December 22, 2008, reducing the future expected load growth and also the potential for conservation savings, it further clarified this observation that program costs are significantly higher than the average costs for the total portfolio:[58]

> *"The unit cost of original DSM program savings, assuming the original level of both expenditures and savings, was $56/MWh. Under a worst-case scenario that assumes all of the decrease in DSM savings comes through programs, the unit cost of DSM program savings, assuming all of the planned expenditures are spent but only 78 per cent of the original savings are achieved, would be $72/MWh…"*

In response to an IPPBC IR, BCH provided the following table showing the range of unit costs that apply to the 21 different unique programs within the Program segment of the DSM portfolio, both before and after the adjustment for the load forecast reduction in the Evidentiary Update.

[57] Exhibit B-3, derived from the response to JIESC IR 1.17.3
[58] Exhibit B-10, Evidentiary Update, page 25

Table of individual program levelized Total Resource Costs[59]

DSM Programs	100% of Original Program Savings		78% of Original Program Savings	
	Energy Savings at F2020 (GWh/yr)	Total Resource Cost Levelized Cost ($/MWh)	Energy Savings at F2020 (GWh/yr)	Total Resource Cost Levelized Cost ($/MWh)
Residential Refrigerator Buy-back	91	$24	71	$31
Residential Voltage Optimization	231	$33	180	$42
Commercial Voltage Optimization	77	$33	60	$42
Industrial Power Smart Partner - Distribution	698	$34	545	$43
Residential Lighting	148	$34	116	$44
Commercial Product Incentive	448	$38	349	$49
Residential Behaviour	309	$40	241	$52
Industrial Mechanical Pulping	941	$41	734	$53
Commercial Power Smart Partner	666	$46	520	$59
Industrial Load Displacement	93	$51	73	$66
Industrial New Plant Design	118	$53	92	$68
Industrial Power Smart Partner - Transmission	742	$59	579	$76
Residential Appliances and Electronics	35	$64	27	$81
Commercial High Performance Building	238	$66	185	$85
Commercial Load Displacement	25	$81	19	$104
Residential Renovation Rebate	23	$92	18	$117
Residential New Home	35	$103	27	$131
Residential Sustainable Community	114	$109	89	$140
Commercial Sustainable Community	28	$110	22	$141
Residential Low Income	73	$112	57	$144
Residential Load Displacement	11	$115	9	$147

Clearly, all programs are not created equally. Some are much more cost-effective than others. Furthermore, if the energy savings that are actually due to the long-term elasticity were properly identified and attributed to the Rate Structures instead of to Program savings, it's quite likely that many of these programs would no longer be considered cost-effective.

Given that the long-term elasticity could have a value of -0.15, there could be 3,000 GWh that is properly attributable to Rate Structures but has been seconded into the Program energy savings by virtue of the fact that BCH elected to deal with a potential double-counting problem by simply omitting to recognize the impact of the consumer price response under Rate Structures. If that much of the savings were reallocated from Programs to Rates, it would effectively double the unit costs of all the programs.

[59] Exhibit B-83, BC Hydro undertaking No. 36 for IPPBC, Note that Total Resource Cost is also known as the All Ratepayers Cost

And given also that a significant portion of the estimated conservation potential has already been incorporated into the Pre-DSM Load Forecast, it's quite likely that the additional savings being expected from Programs and Codes and Standards are over-stated. If so, the program unit energy costs are also under-stated.

The fact is that it's extremely difficult to accurately estimate the potential savings from any given DSM measure or combination of measures. It's even difficult to measure what actually happened after the fact, because you no longer have the unaltered world to compare to.

In making estimates of the savings that can be achieved by any given measure, the program designer must first make informed estimates of several critical determinants, including free riders, free drivers or spillovers, persistence, cross effects on other energy consumption, and even the energy savings from an individual transaction.

By way of illustration, here are several examples that can show how volatile the end result is depending on the values assumed for these critical variables.

Free Riders. In the Application, BCH assumes that the Refrigerator Buy-back program has a free ridership of 59%. That means that 59% of the people either turned in dead fridges, or would have disposed of their fridges anyway, even without the program. In the 2004 evaluation of the program, free riders were assumed to be only 25%.[60] That change in one assumption alone can make almost a 2 to 1 difference in the amount of energy savings attributed to the program, and in the unit energy cost for the program.

Persistence. This refers to the duration of the benefits to be derived from each transaction under the program. The Refrigerator Buy-back program is shown as an 11-year persistence, so the energy saving from any transaction is assumed to endure for 11 years. This is a bit curious because according to the Residential Conservation Potential Review the useful life of a fridge is supposedly 17 years, which means that people must be turning in 6 year-old fridges. If the persistence was changed to 6 years, the savings from the program would be cut almost by half and the unit cost would almost double.

Linkages between Programs and Codes and Standards. Sometimes there are linkages between programs and regulation changes. The efficient lighting program is anticipating a change of regulations to phase out incandescent lamps by 2016.[61] This example is described in Appendix K:

> *"Another example would be an energy efficiency regulation and a DSM program that would cause customers to purchase higher efficiency lighting products. Integration of the two tools involved ending program activity, and associated costs and incremental savings, when the regulation was expected to take effect to avoid double-counting."*

This should mean that the energy savings for this program should subside shortly after 2016, as the remaining savings after that will be attributed to the Codes and Standards component of the portfolio. However, in this case, the calculation model[62] appears to have a continuation of the energy savings out until 2033, showing a present value of 1 million MWh over the 30 year life of the program. If the savings were actually terminated in 2016 the PV of the total savings would be only about 20% of that amount and the calculated unit cost of the program would change from $32 to $160/MWh. This only

[60] Exhibit B-6 of the 2006 IEP/LTAP hearing, BCUC IR 1.274.1, Attachment 1, Evaluation of the Refrigerator Buy-Back Program Phase II Vancouver Island, prepared by Diane Fielding, December 13, 2004
[61] Exhibit B-1, Appendix K, page 123 of 213

[62] Exhibit B-3, Excel model attached to BCUC IR 1.165.1 Attachment 2

serves to show how volatile the program performance can be depending on the key assumptions that are made.

Cross effects. This is another important assumption that can make a big difference to the effectiveness of a program. It most commonly refers to the impact on household heating that results when more efficient appliances or lighting are installed. When efficient light bulbs are used, there is a loss of space heating energy and this will be replaced by the furnace or baseboard heaters. How much of it needs to be replaced will depend on how much of that heating energy was falling in the heating season.

BCH typically assumes that the furnace is on only 5 months per year and that it only needs to replace 75% of the lost heat. If any of these assumptions is inaccurate, then the savings estimate will be inaccurate. The biggest critical assumption that is made in calculating the cross effect energy is that only 20% of the homes are electrically heated. So typically the cross effect will only be in the range of 6-10%. Unfortunately, that may recognize the change in electrical energy, but it ignores the increase in gas heating, which may cause a worse problem from a GHG perspective, if the household heating is gas or even oil.

These brief examples are given not to give an exhaustive critique of DSM forecasts or evaluations, because the IPPBC does not have the budget or the resources to compete with the Power Smart evaluation team that must make all these estimates. Rather, these examples are given to illustrate the point that this is not an exact science. There is a wide margin for error when making predictions about what people will do – or even measuring what people have done.

The IPPBC has reviewed the Power Smart Evaluation Reports filed with the Commission since the date of the last LTAP.[63] IPPBC is of the opinion that these reports would be inadequate to allow the BCUC to make informed judgments about the true cost effectiveness of any of the specific programs. There may have been other reports that have been circulated earlier, but none of these reports gave the critical backup information that could substantiate and validate the key assumptions being made with regard to free riders or drivers, persistence, cross effects, rebound effects, etc. which are the essential building blocks for evaluating any program.

DSM deliverability risk.

BCH is well aware of the risks inherent in these types of forecasts, and has said so at numerous points during the hearing:[64]

> *RESPONSE: …" So as we go further,… if you've got a hundred units of potential in the marketplace, as you go and you try to accomplish more of that potential,… I think your bandwidth to be wrong is reduced. And the difficulty in trying to get more of that potential goes up as you go further up that curve. … if we go forward with a DSM plan in the past, that was targeting a certain level of energy savings, and it's a relatively smaller amount of the total potential,… I think we take that into account as a measure of deliverability risk. I think the fact that you have a broad portfolio and different tools does help. But you also have to take a look at the uncertainty associated with each of those tools and the fact that you're going a lot more further along that curve, that penetration curve, …with respect to the amount of DSM you're having to realize from what's available, from what the potential is."*

[63] Exhibit B-44, these reports were submitted to the proceeding as BC Hydro Undertaking No. 53 to IPPBC
[64] 2008 LTAP Transcript, Volume 9, page 1671

A few pages later, another spokesman outlines BCH's approach to risk assessments;[65]

> *"… subjective assessments of uncertainty are subject to well-known bias to underestimate uncertainty…. There is a bias that tends to sort of underestimate that uncertainty."*

And he sums it up:[66]

> *"… And at the end of day what we're talking about is professional judgment in looking at this, at our past history, and saying, "How much do we as a company think we can really do in this timeframe?*
>
> *And I think what you're hearing from Mr. Hobson, as a person who works in the area, is that they've gone through all the programs, codes and standards, and the tariffs, and say, "How far do we think we can push this … consistent with Mr. Elton's long-term goal?' And wanting to push it and get to a new paradigm. And that's as far as we think we can go."*

3.1. Bias in utility estimates of energy savings.

It is apparently not uncommon for DSM energy savings to be over-stated and unit energy costs under-stated. In response to an IR, BCH provided a copy of an award winning econometric study by David S. Loughran and Jonathan Kulick. It is apparently, highly regarded and the only study of its kind in the field. In their report, the authors state:[67]

> *"The extensive literature on the cost-effectiveness of DSM relies heavily on estimated energy savings calculated by utilities themselves. Utility estimates of energy savings suffer from a variety of biases, however, the most serious of which is selection bias: the possibility that DSM participants will make energy efficiency investments regardless."*

They performed an analysis of several hundred utilities over an 11 year period, to compare the energy efficiency results for utilities with DSM programs to those without programs and statistically verified a bias in the estimates that utilities give when they're claiming the benefits derived from DSM programs. Their conclusions are that:[68]

> *"For the overall sample (324 utilities), we estimate DSM expenditures lowered mean electricity sales by between 0.3 and 0.4 % at an average cost of $0.14 to $0.22/kWh. We estimate DSM expenditures had a larger effect on electricity sales for the sample of 119 utilities reporting positive DSM expenditures in every year. For these utilities, we estimate DSM expenditures lowered electricity sales by between 0.6 and 1.2 percent at an average cost of $0.06 to $0.12/kWh. By comparison, depending on the sample, utilities themselves estimated DSM expenditures lowered retail electricity sales by between 1.8% and 2.3% at an average cost of $0.02-$0.03/kWh. We suspect that utility estimates of DSM program effects are higher than our estimates because utilities generally do not fully control for selection bias."*

Loughran and Kulick point out, by comparing utilities with programs to those without, that the actual energy saved is far less (i.e. as much as 80% less) than the amounts the utilities claim. They cannot explain the cause of this bias. They merely report the observation with some degree of statistical rigor.

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[65] 2008 LTAP Transcript, Volume 9, page 1675
[66] 2008 LTAP Transcript, Volume 9, page 1677

[67] Exhibit B-3 JIESC IR 1.17.7, Attachment 4, Demand Side Management and Energy Efficiency in the United States, by David S. Loughran and Jonathan Kulick, page 21 (3 of 5)
[68] Exhibit B-3 JIESC IR 1.17.7, Attachment 4, page 39

It may mean that utilities have a difficult time accurately estimating free riders, or persistence. Or perhaps they don't adequately allow for rebound effects or economy-wide effects, or perhaps for the cross effects like space heating energy. Whatever the reasons for these findings, they're certainly consistent with the observation that B.C. consumers have been increasing their usage rates in spite of the reported success of every DSM program BCH has promoted.

While Loughran and Kulick's findings may be criticized for being unable to show with 95% certainty that utility estimates of DSM effectiveness are biased upwards (meaning that their costs of DSM are biased downwards), it still represents the best study available for estimating the likely true cost of DSM. BCH and the BCUC need to make decisions about the likely effectiveness of these expenditures and this study appears to be the best available to date.

In light of this overestimation bias, IPPBC suggests that it would be prudent for the Commission to allow a healthy safety margin in the expectations of energy savings from the proposed DSM portfolio. At any rate it would be prudent to allow for a substantial margin of error in the results before relying on DSM to provide *"94% of the incremental energy load in the 2008 Load Forecast Update."*[69]

3.2. DSM Cost Effectiveness – using the TRC and RIM together.

The Minister's Demand-Side Measure Regulation appears to restrict the decision making capacity of the Ratepayer Impact Measure (RIM) but it does not deny its use in conjunction with other metrics. It prescribes that the Total Resource Cost (TRC, also called the All-Ratepayers Cost) should be the primary evaluative tool but the BCUC may also use other analysis it considers appropriate.

Although the TRC provides a total societal view of the overall cost effectiveness of any demand-side measure, IPPBC finds that the RIM metric (also called the Non-participant Test) provides a useful additional perspective. The RIM is the best indicator of the costs that will have to be borne by the utility's ratepayers. The difference between the two metrics indicates the amount of the 'profit" being made by the participant, at the expense of the ratepayer. That difference could also be viewed as the subsidy that will flow from the ratepayers to the participants

To understand why this is so, one needs to look at the components of the two cost metrics:

TRC = BC Hydro Program Costs + BC Hydro Allocated Portfolio Costs

+ Participant Costs + Partner Organization Program Costs

RIM = BC Hydro Program Costs + BC Hydro Allocated Portfolio Costs

+ BC Hydro Incentive Costs + Lost Billing Revenues

If we take the difference RIM – TRC = BC Hydro Incentive Costs + Lost Billing Revenues

- (Participant Costs + Partner Organization Program Costs)

That is to say the difference is simply the amount by which the payments transferred from BCH (i.e. the incentive payments and the bill savings) exceed the participant's costs. That is to say that RIM minus TRC is simply the participant's profit. It's also the amount of the net incentive that appears to be necessary to induce them to participate.

If there is a large difference between RIM and TRC for any given measure, then there appears to be a large profit required for the participants in that measure.

[69] Exhibit B-10, the Evidentiary Update, page 23 states that Option A would now meet 109% of incremental energy load.

The table on the following page shows the extent of the participant profits that appear to be required to gain participation in each of the proposed demand-side measures in BC Hydro's original Application. They were provided in an IR response and also in a model attached to another IR response.[70] These values have since been altered by the Evidentiary Update but BCH was not willing to share the new RIM values due to the Minister's Regulation being issued in the interim.

Nevertheless the values provide a valid illustration of the use of the two metrics together. It's readily apparent from scanning this table that there are a lot of programs that seem to require quite substantial incentives to induce participation.

Another interesting difference that should be clarified when comparing the RIM costs to the TRCs, is the fact that the TRC contains neither the incentive payments nor the bill savings. That means that BCH could offer any amount of incentives for a given measure and that cost would never show up in the TRC. The same is true of the customer's bill savings. If the electricity prices rose higher there would be no impact on the TRC – it is totally cost based. But the RIM would grow, indicating a more and more profitable deal for the participant.

One final point is that comparing TRCs to IPP prices is like comparing apples to oranges. For comparability purposes, the supply–side prices from IPPs are really more like RIM costs than TRCs. IPP prices must be viewed from the perspective of being ratepayer impact prices. They are not from the perspective of a total resource cost. For one thing, IPP prices must contain a built-in profit, just like RIM costs. No-one would evaluate an IPP price from the perspective of a total societal cost. IPP prices are evaluated based on what the charges will be to the utility for the energy received.

If the BCUC were not permitted to look at the RIM unit costs, then it would be impossible to rationally compare demand-side options to supply-side options.

[70] Exhibit B-3 JIESC IR 1.4.12 and the Excel model attached to BCUC IR 1.165.2

Levelized Costs ($/MWh)	All Ratepayers Test	Non-Participants Test
Rate Structures		
Residential	$ 6	$ 111
Commercial	$ 7	$ 100
Industrial	$ 14	$ 86
Total Rate Structures	**$ 9**	**$ 101**
Energy Efficiency Programs		
Residential Sector		
Behaviour	$ 38	$ 142
Voltage Optimization	$ 31	$ 105
Lighting	$ 32	$ 100
Sustainable Community	$ 106	$ 93
Refrigerator Buy-back	$ 24	$ 113
Low Income	$ 110	$ 187
New Home	$ 102	$ 107
Appliances and Electronics	$ 63	$ 143
Renovation Rebate	$ 90	$ 139
Residential Sector Total	**$ 54**	**$ 124**
Commercial Sector		
Power Smart Partner	$ 43	$ 139
Product Incentive	$ 36	$ 125
High Performance Building	$ 64	$ 124
Voltage Optimization	$ 31	$ 107
Sustainable Community	$ 107	$ 97
Commercial Sector Total	**$ 47**	**$ 131**
Industrial Sector		
Mechanical Pulping	$ 40	$ 77
Power Smart Partner - Transmission	$ 57	$ 90
Power Smart Partner - Distribution	$ 31	$ 124
New Plant Design	$ 50	$ 108
Industrial Sector Total	**$ 45**	**$ 99**
Total Energy Efficiency Programs	**$ 47**	**$ 115**
Load Displacement Programs		
Residential	$ 110	$ 143
Commercial	$ 78	$ 141
Industrial	$ 49	$ 112
Total Load Displacement Programs	**$ 76**	**$ 128**
Total Programs (EE+LD)	**$ 48**	**$ 115**
Total Rate Structures and Programs	**$ 35**	**$ 111**

3.3. Load Displacement Projects and Voltage Optimization Program

For the reasons outlined in the BCUC's 2004/05 to 2005/06 Revenue Requirements Application decision of October 29, 2004[71], load displacement projects of any kind should not be considered DSM. They are a form of subsidized generation that is not subject to any competitive bidding process or participation in standing offer programs.

BCH's proposed Voltage optimization program is also not DSM. It is a system upgrade or modification and is the same as any other investment in hardware. In addition no business plan has been provided with respect to it. From a technical perspective it may not produce the desired effect. For example, when voltage drops a baseboard heater will just stay on longer until the thermostat setting is reached. A motor may simply draw more amperage to get the same job done.

For all the above reasons, the IPPBC specifically and respectfully submits that the Load Displacement and Voltage Optimization Programs should be rejected as part of the Application. They simply do not belong in the DSM program.

4. Burrard Thermal

4.1. Introduction

The Burrard Thermal plant ("Burrard") is an antiquated plant with a thermal efficiency of approximately 31%. The IPPBC has been raising concerns about the antiquated nature and inefficiency of this plant on a consistent basis since the association was formed in the early 1990s.

In its requested Draft Order[72] ("Draft Order") BCH states that: "The 2008 LTAP is in the public interest under Section 44.1(6)(a) of the Act" and then goes on to say that the BCUC should endorse a number of items including:

> *"BC Hydro's plan to rely on Burrard Thermal Generating Station ("Burrard") for planning purposes for 900 megawatts of dependable capacity and 3,000 GWh/year of firm energy until at least F2019".*

The Draft Order also states that: "Pursuant to section 44.2(3)(a) of the Act, the following expenditures are determined to be in the public interest" and then says in part:

> *"Expenditure of $1.6 million in sustaining capital expenditures in F2010 required to ensure the reliability of Burrard".*

In support of these requests, BCH is relying heavily on the recent "AMEC Report on Current Condition of Burrard"[73] ("AMEC Report").

[71] Page 195
[72] Exhibit B-10, Attachment 1
[73] Exhibit B-1-1 Appendix J1

4.2. Burrard Thermal – 2007 Energy Plan

The BCUC last discussed Burrard in detail in the BCUC 2006 IEP/LTAP Decision. However, "The BC Energy Plan: A Vision for Clean Energy Leadership"[74] ("2007 Energy Plan") was released after the close of the evidentiary record relating to this decision and it contained the following exclusion[75]:

> *"In Commission Letter No. L-12-07 issued on February 28, 2007, the Commission determined that the 2007 Energy Plan would not form part of the evidence of the proceeding…"*

The 2007 Energy Plan contains a number of very specific references to Burrard and in particular the following:

> *"Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014."*[76]
>
> *"A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.*
>
> *Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.*
>
> *By 2014, BC Hydro plans to have firm electricity to replace that would have produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise."*[77]

And at page 57 of 84 of the same exhibit:

> ***"Policy Action #22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may retain Burrard for capacity purposes after 2014.***
>
> *As a part of its Integrated Electricity Plan, BC Hydro has a plan to replace the firm energy from Burrard Thermal by 2014. The proposed approach by BC Hydro is consistent with Government's desire to see Burrard Thermal phased out. The government recognizes that the value of the capacity and voltage support provided by Burrard Thermal may warrant continuing to keep Burrard Thermal available if needed for peaks in demand for example, resulting from cold winter weather, Christmas lighting,*

[74] Exhibit B-1-1, Appendix B1
[75] Page 9
[76] Exhibit B-1-1, Appendix B1, page 16 of 84
[77] Exhibit B-1-1, Appendix B1

> *to deal with other resources being unexpectedly unavailable etc. These may continue to be appropriate longer term roles for Burrard if that Burrard Thermal continues to be a cost effective voltage support and capacity resource."*

As confirmed by representatives of BCH[78], there is nothing in these policy statements that Burrard is to be continued to be used as a firm energy resource for planning purposes or otherwise. To the contrary, the Government policy clearly "… supports BCH's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources by 2014" for environmental reasons and because: "BCH imports power primarily because the plant is outdated, inefficient and costly to run."

BCH's request for Commission endorsement of its plan to rely on Burrard: "… for planning purposes for 900 megawatts of dependable capacity and 3,000 GWh/year of firm energy until at least F2019." ("Burrard Energy and Capacity Endorsement" or "Scenario 2") is completely contrary to the provisions of the 2007 Energy Plan with respect to energy for all the reasons cited in the extracts above. Because or its age, inefficiency and environmental impacts it is not suitable as an energy source, other than incidental energy generated when capacity is provided, for planning or any other purpose.

4.3. Burrard Thermal – Shareholders Letter

As well as being contrary to the 2007 Energy Plan, the proposed 3,000 GWh use of Burrard is contrary to the Shareholder's Letter[79]. As noted in an exchange between the Chairperson and the President of BCH[80], the President agreed BCH is obliged and mandated to embrace the 2007 Energy Plan Initiatives that are attached to the Shareholder's Letter of Expectations:

> *"THE CHAIRPERSON: And the only thing I wanted to point out, and I'm sure you'll do it for me, is that page 1 of the letter – page 2 of the letter says:*
>
> *"Government has provided the following mandate direction to B.C. Hydro…"*
>
> *And then the third bullet speaks of the province's Energy Plan, and then a list of the Energy Plan initiatives relating to B.C. Hydro is enclosed as Appendix 1. An on page 7 and 8 the Appendix 1 sets out all the policy actions that refer to B.C. Hydro.*
>
> *MR. ELTON: A: Yes.*
>
> *THE CHAIRPERSON: So this is a little stronger, I think, than -- I think the remark you made is that you would be imprudent to ignore these things. I think this really obliges you, mandates you, to embrace them.*
>
> *Mr. ELTON: A: Yes, I think that the remark I've made that it would be imprudent to ignore them, related to other statements that government might make from time to time that might be strong statement but that wouldn't be in this kind of letter."*

Included in the 2007 Energy Plan initiatives attached to this letter is:

[78] TR V-4, pages 440-445
[79] Exhibit B-17
[80] TR, V6, page 838

> *"Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014."*

The firm energy supply from Burrard is supposed to be completely replaced with other resources and not merely reduced to 3,000 GWh from 6,000 GWh. BCH is not advancing a replacement proposal for the firm energy from Burrard as it is mandated and obliged to do in accordance with the Shareholder's letter and is in contravention of it.

4.4. Burrard Thermal - AMEC Report

Scenario 2 consists of 900 megawatts of dependable capacity and 3,000 GWh of firm energy. Currently, Burrard does not have this capability as indicated by the following extract from the AMEC Report[81] (The capitalization of the word "NOT" is as set out in this report and the IPPBC has not added it as emphasis):

> *"**Cost Implications of Scenarios 1, 2 and 3**: Burrard TGS is NOT at present in a condition consistent with Scenarios 1,2 and 3 set out above where 900 MW of generation capacity is consistently critical over the next twenty years (an N+0, where N=6" role). Without significant investment in detailed inspections in the next two years and procurement of critical spares, extended single unit outages (and possibly multiple unit outages) due to major critical equipment failures, is a reasonable position in the next 2 to 5+ years (depending on the scenario)"*[82]

One of the units at Burrard did fail during a period when about 4,000 GWh of energy[83] was produced at the plant in 2001:

> *"QUESTION:*
>
> *Please confirm whether there was a catastrophic failure at Burrard in 2001 or 2002, and if so, identify the cause of that failure:*
>
> *RESPONSE*
>
> *In April 2001 there was a significant unit equipment failure. The failure was of the 5th stage intermediate pressure turbine on G2. The unit automatically shut down due to high vibration levels. The problem was determined to be a metallurgical defect resulting in cracking and loss of disk material…."*[84] [85]

[81] Exhibit B-1-1, Appendix J1, page 8 of 167
[82] Exhibit B-1-1, Appendix JI, page 6 of 167, "Scenario 1: 600 GWh/Yr - six generating units providing winter peaking capacity and generation averaging 200 GWh/yr to 1500 GWh/yr; Scenario 2: 3000 GWh/Yr – six units providing 3000 GWh/yr of intermediate capacity providing seasonal baseload generation and intermediate generation through the rest of the year, with little or no summer generation; and Scenario 3: 6000 GWh/Yr – six units providing 6000 GWh/yr of year round baseload generation.
[83] Exhibit B-1, page 5-25, Figure 5-7
[84] Exhibit B-20
[85] In Exhibit B-1-1, Appendix J1, page 53 of 167, it says: "In summary all units experienced row 5 blades and attachment problems over the years. The problems varied in severity, worst being Unit 2 where a section of the fifth disc separated and caused extensive damage in 2002.

In addition, BCH has confirmed[86] the difficulty in obtaining spare parts for Burrard which was first raised by the IPPBC in the BCH 2006 IEP/LTAP hearing[87]:

> *"QUESTION*
>
> *Please confirm that it can take up to 18 months to replace a major component in the Burrard Thermal plant because stock spare parts are no longer available:*
>
> *RESPONSE*
>
> *At Burrard Generating Station, the major component that is expected to take the longest time to replace is the steam turbine. Suppliers advised BC Hydro during 2000 and 2001 that delivery of a replacement turbine would, at that time, take 14 to 16 months. Based on this information, BC Hydro, for planning purposes, estimated that the time to replace the turbine would be up to 18 months.*
>
> *It should be noted that in the event of a major component failure, the actual time for repair will depend on the nature of the failure and other prevailing circumstances – including supplier availability. Also, depending upon the nature of the event, the cost of repair, and other factors, consideration may be given as to the whether the repair of the unit would be appropriate."*

Before BCH can include Burrard in its Base Resource Plan, it must first demonstrate that the plant is technically capable of operating at the energy and capacity levels set out in this plan. According to the AMEC Report, Burrard is not in a condition consistent with Scenarios 1, 2 or 3 (see footnote 23 for the energy and capacity amounts for each of the scenarios). Yet, currently BCH is including Scenario 2 in its Base Resource Plan even though it has no basis for this. The technical capability of Burrard has long been a source of frustration for the IPPBC and now the AMEC Report now confirms what the IPPBC has long suspected. Because of the AMEC Report, Burrard also fails the capability test established by SD10. The fact that SD 10 doesn't take effect until 2016 should be considered in light of the Government's Energy Plan Policy Action #22 which effectively said Burrard would be phased out by then.

BCH's response to the deficiencies set out in the AMEC report is the following[88]:

> *Q: "is… NOT, N-O-T in capital letters, "… at present in a condition consistent with scenarios 1,2 and 3 set out above where 900 megawatts of generation capacity is consistently critical over the next 20 year.."*
>
> *A: Yes. I would just qualify, we aren't at this point relying on it for 20 years. We're relying on it through the completion of ILM, which is – the date there is 2019."*

BCH's qualification that it is only relying on the plant in the Base Resource Plan[89] until 2019, even though it is shown in the plan as a resource until 2028, does not address the negative capability conclusion in the AMEC Report for the period 2009 to 2019. Without doing the inspections and

[86] TR, V6, pages 953-954
[87] Exhibit C17-14
[88] TR, V6, page 945
[89] Exhibit B-10, page 29, Table 2-10 and page 30, Table 2-11

considerable investment called for by the report, BCH is still relying on Burrard as if this work had been completed as evidenced by the following exchange[90] during cross examination:

> *"Q: Well it says:*
>
> *"Without significant investment in detailed inspections in the next two years…"*
>
> *"…and procurement of critical spares, extended single unit outages and possibly multiple unit outage due to major critical equipment failures, is a reasonable position in the next two to five-plus years…"*
>
> *So according to this, it would appear that your consultant is saying, "Get your inspections done in the two years and start ordering some spares."*
>
> *"Q: Is that not what this says?*
>
> *A: That's what he is saying, and I'm saying we need to ramp up to this level of activity, given the other activity that's going on in the plant."*

The IPPBC respectfully submits that on the basis of the AMEC Report, Burrard is not capable of providing the energy and capacity set out in Tables 2-10 and 2-11 and it cannot be included in the Base Resource Plan up to 2019 or beyond.

In the alternative, the BCUC should at a minimum not include Burrard until BCH files and the BCUC concludes its review of a certificate of public convenience and necessity to carry out the required work in the AMEC Report. Currently, BCH is requesting the BCUC to approve "Expenditures of $1.6 million of sustaining capital expenditures in F2010 required to ensure the reliability of Burrard." A $1.6 million expenditure is not going to ensure the reliability of Burrard.

As set out in the following exchange between the President of BC Hydro and Chairperson Pullman the initial estimated cost of expenditures is in the order of $310 million[91]:

> *"THE CHAIRPERSON: And AMEC's conclusion was that if you incurred expenditures of about $310 million over the planned period of base capital, availability capital and probability capital, the station could generate 3,000 gigawatt hours a year.*
>
> *MR. ELTON: A: Yes….*
>
> *THE CHAIRPERSON: So am I fair to assume that it is not your intention to take this to – to make a request for capital expenditure for Burrard of $310 million?*
>
> *MR. ELTON: A: No, that's not correct. I think this is an area where we are obviously very interested in the Commission endorsing the plan. It's understood, and I think we have mentioned this last week, that if we did intend – you know, if and when we intend to spend that kind of money we would be coming back for a different regulatory process, and we would also be addressing that in our service plan…*

[90] TR, V6, pages 946-947
[91] TR, V-6, page 851See also

> *THE CHAIRPERSON: Okay. Because I get the distinct impression that there are two Burrards. There's the physical Burrard, which is what it is, and the paper Burrard, which is what AMEC says it might be if you spend $310 million, or could be.*
>
> *MR. ELTON: A: There certainly is a Burrard for planning purposes and a Burrard that actually operates, and I think we've made that clear through."*

The AMEC Report doesn't distinguish between planning or operating. Burrard is not capable for either, assuming this distinction should be made. The $310 million figure is subject to the results of the detailed inspections which are referred to in the AMEC Report and which were the subject of cross examination by the IPPBC[92]. In addition, there is the following summary exchange on the cost risk[93]:

> *"Q: I'd like to turn your attention Exhibit B-1, and that's page 6-15…*
>
> *Q: And in lines – starting at line 13 it says:*
>
> *"Cost Risks. The major cost risks are the number of critical spares required and any cost of other systems identified in the AMEC study that require refurbishment. Mitigation of the cost risks is provided somewhat by detailed inspections. Should the detailed inspections result in the degree of refurbishment work being more substantial and expensive than anticipated, BC Hydro may have to reconsider the maintained Burrard as currently configured option."…*
>
> *Q: And without the detailed inspections, including opening up of the units, how will you know what the final bill is?*
>
> *A: Well, we won't. We're not here asking for approval for our final bill. We are going to bring forward a program which we'll take to our board in the fall…"*

It is one thing to include in the Resource Plan new or potential resources such as Revelstoke Unit 5 and Mica Unit 5 or resources from the Clean Power Call, that include attrition, because there is nothing to indicate that they won't provide the specified amounts of electricity. However, the IPPBC respectfully submits that is not acceptable to include Burrard in this plan when recent reports show that it is not capable of providing the electricity indicated in the plan and which the AMEC Report indicates will meet this capability at a cost of $310 million and potentially higher depending on the results of physical inspections. As indicated immediately above, there is the possibility that detailed inspections my require BCH to consider other options. BCH has also said that it won't take its "program" to its Board until the fall.

Under these circumstances, it is not possible for the BCUC to accept BCH's request for the Burrard Energy and Capacity Endorsement or approve $1.6 million in sustaining capital expenditures when according to AMEC's estimates, $310 million and perhaps more is required, and BCH's Board of Directors hasn't approved the "program".

The IPPBC also questions what an expenditure of this magnitude will bring BCH. The IPPBC will hold its detailed comments in this respect until a certificate of public convenience and necessity is brought forward for regulatory review but notes that BCH's primary reason for wanting to include Burrard in the Base Resource Plan is because of the ILM in-service date risk. Perhaps consideration should be given to

[92] TR, V6, pages 923 to 931
[93] TR, V6, pages 947 to 948

using some of this money to eliminate this risk instead of spending it on a very inefficient and old plant. Because of its ramp and ramp down times, unlike a hydro electric turbine and generator, it is a very poor at following load or loss of other generation. None of the proposed expenditures will improve its approximately 31% efficiency[94]:

> *"Q: By the way, when you make that investment in Burrard, will it have any impact on your efficiencies that you actually achieve form the plant?*
>
> *A: I don't believe so. There may be some marginal efficiencies here and there, like if you replace – you know, there could be some energy savings in the station service, for example. I think the fundamental steam cycle will be unchanged."*

Lastly, very little attention has been paid to the annual operating costs of Burrard. These must be included as part of an application for a certificate of public convenience and necessity. As a prelude, BCH's response to an IPPBC Information Request[95] provides some insight at to what they might be:

> *"Once Revelstoke Unit 5 and the planned Nicola to Meridian 500 kV transmission line (5L83) are in service, BC Hydro anticipates that the main requirement for Burrard operation will be to provide dependable capacity to assist in meeting system reliability needs, as opposed to meeting reliability needs within the LM/VI region. The estimated average annual Burrard dispatch for meeting system reliability requirements is 600 GWh/year, and the estimated annual operating cost at this level of production in F2017 would be in the range of approximately $85-119 million (2008 dollars). This estimate is inclusive of costs for fixed and variable OMA, sustaining capital, gas transportation, gas commodity and GHG offsets as detailed in the table below."*

When compared to additional units at Mica and Revelstoke, these are very expensive operating costs for a capacity resource that in practice will produce virtually no energy and very expensive energy at that.

4.5. Burrard Thermal – 6,000 GWh – Social Licence

For all the reasons described under the headings "Burrard Thermal – Energy Plan", "Burrard Thermal – Shareholder's Letter", Burrard Thermal – AMEC Report and Burrard Thermal SD10 the IPPBC is equally opposed to any proposal to include Burrard in the Resource Plan at a capability of 900 MW and 6,000 GWh as it is to 900 MW and 3,000 GWh. For some of the same reasons that the IPPBC is against Scenario 2, BCH is against Scenario 3 which puts BCH at cross purposes with itself. For example[96]:

> *"A ...It's back to the principle I talked about earlier on that we came to fairly early in setting these studies. If our argument for the capability of the plant depends on the plant not running, that's not an argument that – that argument by definition -- that kind of argument doesn't have integrity in terms of meeting the spirit and intent of SD 10. It's an attempt to subvert SD 10 to get around it. So it's not a principled argument that would [sic] could take forward."*

[94] TR, V6, page 1015
[95] Exhibit B-12, BCH response to IPPBC IR 3.18.2
[96] TR, V7, page 1237

In practice, because of the thermal inefficiency of Burrard, this is exactly what will happen at the 3,000 and 6,000 GWh levels and yet BCH is advancing the argument with respect to the former and not the later. It will be a mask for imports and the only difference will be the increased size of the mask.

The IPPBC agrees with BCH that social licences do exist for facilities such as Burrard especially where regulatory authorities can unilaterally amend the terms of existing environmental permits. For example[97]:

> *"A: I am aware of that, and certainly we have said that there is a social licence currently for operating in its current peaking function. But for example, when – there was an article in the Globe and Mail when the District Director for Metro Vancouver was made aware of the 2008 LTAP filing, and the – essentially the desire to run Burrard at 3,000, he was alarmed, and suggested that they may have to look at – that there was nothing currently in the permit stopping Burrard from doing that, but they may have to take a look at that and consider re-opening it. And certainly that is within their right. It's set out in the Air Quality Management By-law for Metro Vancouver that the District Director can amend a permit if they believe it's for the protection of the environment.*
>
> *A: I think the point I would make is that this social licence is tied not just to the actual operation of Burrard but to the planned reliance on Burrard. And we saw that in – the article in the Globe talked about the planned reliance and that alarmed people."*

As well the same BCH witness said[98]:

> *"A: No, I think what I'm saying, we didn't make that assumption. For instance, for a permit you don't look at the actual operation or even the expected operations. You look at the maximum possible operations. And I do believe that if there was a plan to increase those operations from the current baseload functions that there has been since 2000, we've seen the evidence that the district director would consider reopening the permit."*

There is a direct link between the pollution produced at Burrard and adverse human health effects which makes any operation of this plant more difficult for the public to accept[99]:

> *"Q: Just to follow up, in the sense that, although you're not a medical doctor, would it be fair to say that the Burrard Thermal Plant produces such as oxides of nitrogen and small particulate, that might have an – that has – that might have an impact on human health.*
>
> *A: Yes, it does. And so Burrard has – emits nitrogen oxides, and a small amount of particulate matter. But one of the main concerns with the emission of nitrogen oxides, they do have some health effects on their own, but more importantly, they are involved in the secondary formation of ozone and fine particulate matter. And those are really the two key air contaminants of concern when it comes to human health.*
>
> *Q: And would you agree with me that those are the most difficult to deal with, in terms of public perception of whether a plant should be in operation or a product should be made on the thermal generation side, using natural gas?*

[97] TR, V7, pages 1065-1066
[98] TR, V7, page 1218
[99] TR, V6, page 967

> *A: Yes, I would, and I would also suggest that the regulators within this province feel that those are the two priority air contaminants within the province, and particularly within the Lower Fraser Valley airshed."*

Public concern about the health impacts of natural gas fired thermal plants was raised in the National Energy Board hearing into the proposed SE2 generating plant which is in the same air shed. Public opposition was based on health impacts[100] and according to a BCH witness, sufficient public consultation did not allay these fears[101]:

> *"A: I just wanted to say that, in response to your question regarding public consultation and whether it was sufficient, certainly for SE 2, the proponent went through the permitting process, which has requirements for public consultation and therefore they would have done public consultation. And yet there was still considerable opposition to the facility, even though they did do dispersion modeling and all the ambient air quality standards were met. However, there was concern about – with regards to the fact it was – it's a sensitive airshed, the Lower Fraser Valley, and also a concern with regards to polluting up to a limit. So, again, despite the fact that there was public consultation, that wasn't sufficient for them to be able to move forward with building the facility."*

Running Burrard at anything other than a backup capacity plant which produces incidental energy of about 600 GWh is threat to its existence. As soon as BCH argues, in order to ally public concerns, that its actual operation won't be nearly as high as its planned operation, it subverts the intent of SD 10, the terms of the 2007 Energy Plan and Shareholder's letter.

The IPPBC is not aware of any extensive stakeholder engagement program that BCH has undertaken about its Scenario 2 plans for Burrard. Certainly, no consultation has been done for Scenario 3[102]. This may cause public backlash if the BCUC decides in favour of BCH's Burrard proposals without the consultation first being done.

4.6. Burrard Thermal -- GHGs

The IPPBC does not understand how operating Burrard at the 6,000 GWh or even 3,000 GWh will be of assistance in reaching the Government's goal of reducing greenhouse gas emissions by 33 per cent by 2020 from 2006 levels. The issue is one of reduction and not just finding offsets. According to a BCH witness[103]:

> *"A: Part of the reason for that is that if Burrard ran at 4,000 gigawatt hours per year, it would be the largest point-source of greenhouse gas emissions in the entire province. At 3,000, it's the second-largest. But given the government's goal of reducing greenhouse gas emissions by 33 percent by 2020 from 2006 levels, we do feel that it is certainly a higher risk scenario than running at 3,000 gigawatt hours per year, and also just the fact that it will be operating considerably more, another 1,000 gigawatt hours per year, and therefore there would be much more by way of emissions of nitrogen oxides, which again*

[100] TR, V6, page 965
[101] TR, V6, page 966
[102] Exhibit B-1, page 5-34: "RWDI states that the only way to renegotiate the social licence to encompass Scenario 3B is for BC Hydro to conduct a stakeholder engagement program."
[103] TR, V7, pages 1065-1066

> *are involved in the secondary formation of particulate matter and ozone.. So we do think there is certainly more risk for running at 4,000 than running at 3,000."*

4.7. Burrard – SD 10

In the context of Burrard, the following provisions of SD are important:

> *"3.*
> *... the commission must use the criterion that the authority is to achieve energy and capacity self-sufficiency by becoming capable of ...*
> *meeting by 2016 and each year thereafter, the electricity supply obligations, and…*
> *solely from electricity generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities."*

Because of the lead times required to bring on new generation of any kind, self-sufficiency by 2016 is not a problem that can be put off until tomorrow. The IPPBC respectfully submits that "becoming capable" must be viewed, when applied to Burrard, in terms of the Energy Plan and Shareholders letter. Both of these documents don't envisage Burrard as being an energy provider except as incidental to the provision of capacity. They are clear evidence of the intent of the Government with respect to the term "becoming capable". As well as the first quotation set out under the heading "Burrard Thermal – 6,000 GWh – Social Licence" as referenced by footnote 38, BCH responded as follows to a BCUC Information Request[104]:

> *"Any strategy that would only be practical or economic based on an underlying assumption that the actual operation of Burrard would be much lower than the specified level of firm reliance on Burrard because if would be displaced by external market purchases or non-firm Heritage hydro is, in fact, tantamount to reliance on external markets and non-firm Heritage hydro."*

The IPPBC fully agrees with BCH's statement. The key words are "practical" or "economic". With expenditures in excess of $310 million, for planning purposes, Burrard may in theory be capable of providing 3,000 GWh of energy and 900 MW of capacity but in practice and because of economics, BCH will be relying on external markets and non-firm Heritage hydro. According to the following in SD 10:

"(2) The definition of "firm energy capability" in subsection (1) must be interpreted for the purpose of this Special Direction so as to be consistent with the fact that, in 2006, the authority's firm energy capability was 42 600 gigawatt hours."

And SD 10 defines "firm energy capability" as:

> *"the maximum amount of annual energy that a hydroelectric system can produce under critical water conditions;"*

The result is that non-firm Heritage hydro energy is not included for the purposes of SD 10 which is precisely what would happen in Scenarios 2 and 3. Non-firm Heritage energy would be brought in through the "back door" as would imports. With respect to imports, BCH confirmed that the following

[104] Exhibit B-4, BC Hydro response to BCUC IR No. 2.215.2, page 5of 6

statement from a BCH witness in the 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan proceedings is correct subject to BCH: "not masking anything"[105]:

> *"…So, those were the things that fell out. The only thing I will say about Burrard is --- and I will just give you a prelude to after lunch, is that we're very clear that Burrard is no longer economic for providing energy and really, when you think about providing energy from Burrard, we're buying from the market. And its been masking that for several years now."*[106]

By including Burrard in the Resource Plan at the 3,000 GWh level, BCH is taking a very creative approach with respect to the definition of "capable" in SD 10. BCH used a similar approach to conclude that with respect to the Utilities Commission Act and Heritage Contract Special Direction #1 and # 2 it should be able to use 100% debt and no equity. The BCUC[107] agreed with this approach which was subsequently changed by BCH's shareholder, the Province of B.C, so that it is crystal clear that the appropriate level is 70% debt. Just because BCH's shareholder is the Government of B.C. doesn't mean that BCH's interpretations of Provincial Government instruments and policy are consistent with its shareholder's intentions.

For all the above reasons under the heading "Burrard" the IPPBC specifically and respectfully submits that the BCUC should reject BCH's inclusion of Burrard in the Base Resource Plan – Energy Table and determine that the requested expenditure of $1.6 million under section 44.2(3)(a) of the Utilities Commission as not being in the public interest..

5. SD 10 – Insurance

Under SD 10, energy self-sufficiency requires that:

> "*3.*
> *… the commission must use the criterion that the authority is to achieve energy and capacity self-sufficiency by becoming capable of*
> *(d) exceeding as soon as practicable but no later than 2026, the electricity supply obligations by at least 3000 gigawatt hours per year and by the capacity required to integrate the energy in the most cost-effective manner*
> *solely from electricity generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities.*"

Given the very high level of risk that BCH is taking with respect to its Power Smart programs i.e. "DSM represents approximately three quarters of the F2020 13,400 GWh load/resource gap" or "94 per cent of the incremental energy load in the 2008 Load Forecast Update[108], the IPPBC thought BCH's interpretation of the "insurance" requirement of SD 10 would have been a relatively straight forward exercise. Including giving the words as soon "as soon as practicable" their common, every day meaning. In other words, SD 10 mandates BCH with acquiring additional amounts of energy "as soon as practicable" but no later than 2026.

There is also the second requirement that appears after the word "and" which is to acquire the capacity that is "required to integrate the energy in the most cost-effective manner". The words "cost-effective"

[105] TR, V-4, page 450
[106] Exhibit C17-9
[107] BCUC 2006 LTAP Decision, page 202
[108] Exhibit B-10, pages 22 and 23

specifically apply to "capacity". In support of this interpretation, the IPPBC notes section 6(b)(i) of Terms of Reference for the BCUC Inquiry under section 5(4) of the Utilities Commission Act ("Section 5 Inquiry") relating to B.C.'s electricity transmission infrastructure and capacity needs for the next 30 years says:

> *"British Columbia is to achieve energy and capacity self-sufficiency by 2016 and maintain self-sufficiency after achieving it, which for BC Hydro includes an additional 3,000 GWh of supply per year from electricity generation facilities within the Province as soon as practicable but no later than 2026."*

There is no reference to cost effectiveness for the 3,000 GWh which is energy and not capacity.

The IPPBC is not suggesting that BCH acquire the 3,000 gigawatt hours per year on a "blank cheque basis". It would be acquired as soon as practicable on a competitive bid basis. Given the high risk associate with the expected electricity savings from Power Smart, spending more money on Power Smart to provide insurance would not be in accordance with BCH's "3 buckets" risk diversification strategy. As first set in its 2006 IEP/LTAP application[109] it consists of the "DSM Bucket", the "Resource Smart Bucket" and the "IPP Bucket".

It is not only a question of diversification. With a high risk factor, the price of cost effective Power Smart rapidly increases.

On cross examination the IPPBC elicited the following response from a representative of BCH with respect to SD 10[110]:

> *"A: Yes, that shows that by 2026, as according to Special Directive 10, we have a 3,000 gigawatt hour surplus.*
>
> *Q: And this is not meant to be a legal interpretation, but why is B.C. Hydro not capable of attaining a 3,000 GWh level prior to 2026?*
>
> *A: We could acquire that surplus sooner. If you read Special Direction No. 10, it actually uses the word "practicable". And we think practicable has a cost-effectiveness test to it, and we think we need to do a lot more analysis before we determine when it's practicable to bring on 3,000 gigawatt hours of insurance. How much would it cost, what you could sell it for in the market, and, importantly, do you have the transmission to actually get the insurance out of the province? For example in a high water year, we could have as much as 13,000 gigawatt hours of surplus, and right now the transmission capability is more like 10,000 gigawatt hours. There's a lot of important questions that need to be asked and answered and analyzed before I think we'd be in a position to make a decision on when it's practicable to bring on the insurance."*

Assuming none of the IPPBC's arguments with respect to Burrard are accepted by the BCUC and it remains in the Base Resource Plan at 3,000 GWh, then BCH's estimate of 13,000 gigawatt hours of surplus in a high water year is 3,000 GWh too high. Because of its inefficiency, it is not going to run in high water years at this level. If it does, then BCH will have a lot of explaining to do to the residents of the Fraser Valley about its social licence. With a current export transmission capability of 10,000 GWh, transmission is not a constraint to selling any surplus.

[109] BCUC 2006 LTAP Decision, pages 90 to 95
[110] TR, V4, pages 451 and 452

The IPPBC cross examined additional representatives of BCH about SD 10 as follows[111]:

> *"Q: And could you please explain to the Commission what goes into the calculation of this cost-effective test?*
>
> *A: We haven't to this point figured out exactly how we'd go about determining what cost-effective or practicable is. That's something that we wanted to get to a point of self-sufficiency first, and we haven't yet determined whether and if it made sense to advance that insurance premium earlier than fiscal 2026.*
>
> *A: What did though, in the development of this long-term plan, was to determine that it's simply too early right now to consider taking actions to gather the insurance provision in SD 10, and that we would, as Mr. Reiman said, revisit it at another time."*

BCH appears to be replacing practicality with convenience in relation to its interpretation of SD 10. It was ordered and approved on June 5, 2007 which gave BCH ample opportunity to incorporate its provisions into the Application. It is not a case of obtaining self-sufficiency and then moving on to the insurance requirements. BCH must do both at the same time.

In a response to an Information Request[112], BCH provided a table that shows as a line item entry the "2007 Mid Load Forecast Surplus/Deficit" ("2007 Table"). It is a proxy for the insurance requirement of SD 10. This table was recast in the Evidentiary Update[113] as Table 2-10. It has a line item entry entitled "2008 Mid Load Forecast". The difference in the entries for the insurance coverage in each of the years shown in the tables is stark. In the 2007 Table the coverage increases to 2,500 GWh by 2016, decreases to a low point of 100 GWh by 2023 and rebounds to 3,600 GWh by 2026. In Table 2-10 it is - 500 GWh in 2014, increases to 1,700 GWh by F2016, drops sharply thereafter but staying in a range of 300 – 700 GWh until 2024 and then climbs to 1,700 GWh by 2026. The 2007 shows a more even approach in relation to the provision of insurance coverage.

The difference between the two tables was put to BCH for explanation and it responded[114]:

> *"A: Well the answer is we didn't – as we set out what kind of balance to have in our load resource balance in those years, we didn't consider any of it to be part of the insurance provisions in SD 10."*

But for the dip to the low point of 100 GWh in 2023, the 2007 Table shows "insurance" values that are far more consistent with the "as soon as practicable" requirements of SD 10 than Table 2-10 that in some instances shows negative values. For unknown reasons, the values in the 2007 Tables e.g. 2,500 GWh in 2016, didn't present any cost or transmission problems for BCH.

BCH could not point to any instrument where, for the purposes of SD 10, the word "practicable" is defined. The IPPBC's review of what Canadian case law reveals that "practicable" has been defined as "able to be effected, accomplished or done"[115]. There is a labour arbitration case[116] and a decision of the Ontario Financial Services Commission[117] that come to similar conclusions.

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[111] TR, V12, page 2285
[112] Exhibit B-3, BCH response to BCUC IR 1.139.1
[113] Exhibit B-10, Table 2-10, page 29
[114] TR, V12, page 2284
[115] Laframboise v. Woodward 2002 CanLII, 49471

The IPPBC respectfully submits that BCH's response to the insurance provision of SD 10 is not supportable in law. There is nothing impeding BCH from acquiring additional sources of electricity under its Resource Smart program or from IPPs for insurance purposes thus simultaneously pursuing its high risk Power Smart program, Resource Smart and acquisitions from IPPs for the purpose of the self-sufficiency provisions of SD 10. They are not courses or action that have to be carried out in series and must be carried out in parallel.

The year 2026 is an end date for acquiring insurance and it is not the signal to start acquiring it, as indicated in Table 2-10, in a material way in 2023. The IPPBC respectfully submits that "as soon as practicable" means exactly that and BCH should get on with acquiring the necessary energy and cost effective capacity required to integrate this energy, sooner rather than later.

The IPPBC specifically and respectfully submits that the BCUC should reject BCH's interpretation of SD 10 in relation to insurance.

6. Natural Gas Price Forecast

For all its complexity and the amount of information that has been filed in response to Information Requests, the forecast for the price of natural gas that BCH is relying on[118] can be reduced to two things:

1. BCH's is basing its Application on the Base Case[119] price of natural gas growing at 1.5% in the Base Case which is the calculated annual compound rate of increase in the forecast from 2010 to 2020 in real dollars which is then extended from 2020 to 2027; and

2. BCH has filed evidence that the probability of its high case natural gas price occurring, 53%, is greater than its base case, 44%[120] .

The figure of 1.5% comes from Exhibit B-31, a BCH Undertaking to the IPPBC which states:

> *"**QUESTION:***
>
> *Please confirm the factor applied to extend the Natural Gas Price Forecast provided by Mr. Lauckhart to extend it to 2027.*
>
> ***RESPONSE:***
>
> *The factor applied to extend the Natural Gas Price forecast from 2020 to 2027 is based on the calculated annual compound rate of increase in the forecast from 2010 to 2020 in real dollars. These rates are different for each of the three forecasts and are as follows:*
>
> ● *High case annual rate is 1.9 per cent.*
> ● *Mid case annual rate is 1.5 per cent*

[116] Canadian Union of Postal Workers and Canada Post Corp. {2002] C.L.A.D No. 212, "possible or feasible, able to be done, capable of being put into practice or being used"
[117] Ontario Financial Services Commission in C.R. v. Lombard General Insurance Co. of Canada [2003] O.F.S.C.D. No. 179, "that can be done or used, or possible in practice".
[118] Exhibit B-1, Appendix I
[119] Exhibit B-1, Appendix I, page 28 of 49
[120] Exhibit B-1, Appendix I, page 32 of 49

- *Low case annual rate is 1.1 per cent"*

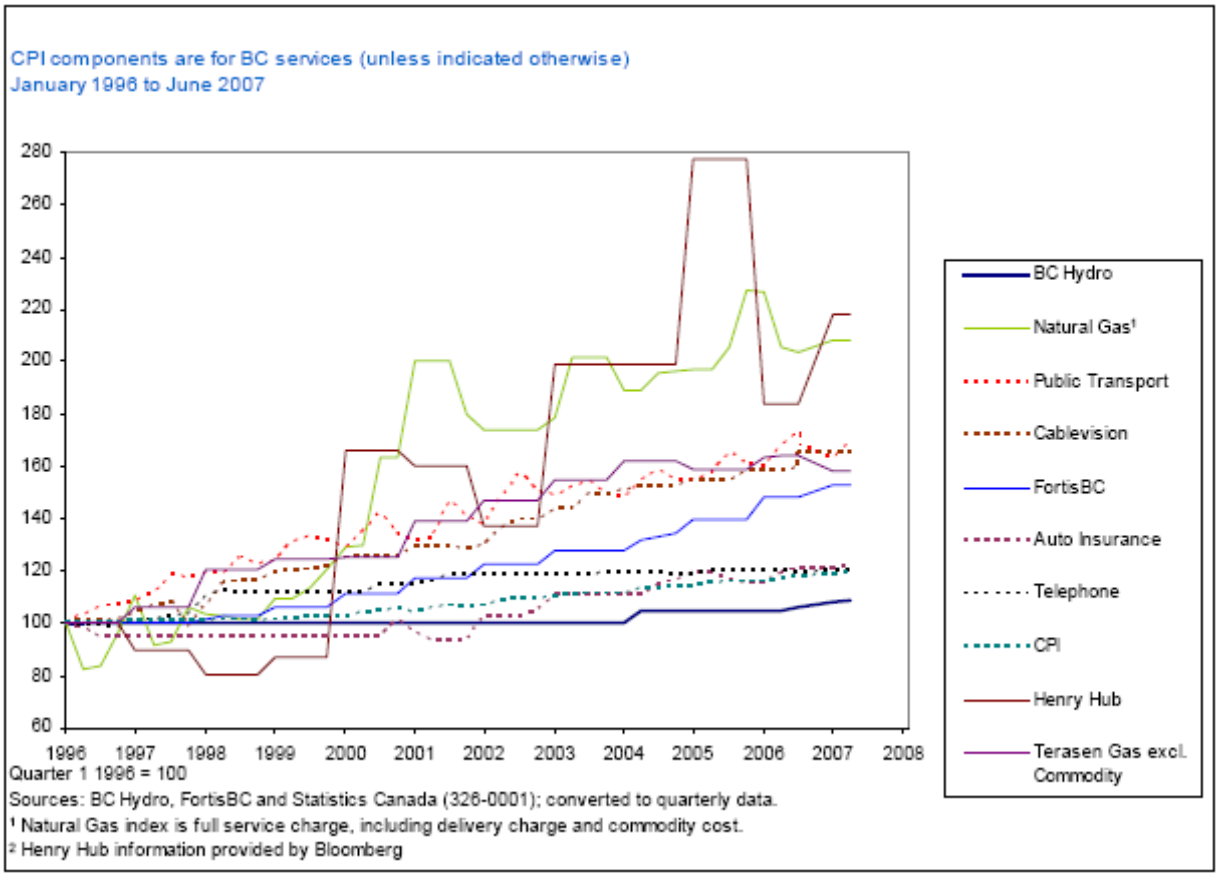
The Mid case annual rate of 1.5% per cent is identical to the natural gas price forecast that is contained in the following extract from BCH's 1995 Integrated Electricity Plan[121]:

> *"BC Hydro regularly prepares and updates an outlook of natural gas prices. The present outlook assumes market prices at Huntingdon hub, considering the three key variables describe above, and includes a real price escalation of approximately 1.5 per cent per year."*

The three key variables that determine Huntingdon prices are[122]:

> *"● U.S. Gulf Coast prices, represented by spot prices at the Henry hub in Louisiana*
> *● the basis differential between Henry hub and Huntingdon hub spot prices; and*
> *● the Canadian/U.S. dollar exchange rate"*

Exhibit B-87 shows what actually happened to the price of natural gas at Henry Hub from 1996 onwards:



While the price of natural gas has dropped significantly in 2009 with the decline in the U.S. economy, and is very volatile, the upward trend is clear and has been in excess of 1.5% annually in real terms during the

[121] Exhibit C17-20, page 7-18. It should be noted the planning period for this IEP is 20 years as per page 7-18
[122] Exhibit C17-20, page 7-15

period shown on the graph. As part of the review of the Application, the IPPBC filed its own forecast[123] and in summary it says:

> *"BC Hydro's natural gas price scenario significantly underestimates the realistic price paths for natural gas. BC Hydro's medium and high cases should really be seen as low and medium cases, respectively, with an additional high case linking North American natural gas prices to world oil and gas markets, through Liquid Natural Gas ("LNG"). BC Hydro's natural gas prices under the low and medium scenarios are not consistent with:*
> *1- industry's consensus on marginal costs of production in North America*
> *2- LNG world prices and market dynamics*
> *3- consensus of forecasters on long term natural gas prices*
>
> *The assumptions surrounding the Californian Energy Commission ("CEC") high case scenario are more in tune with the current consensus view of fundamentals affecting long-term natural gas prices. Thus, this high case should represent the base case scenario for LTAP, with a low case based on the marginal cost of U.S. domestic supply and a high case on competition for oil-indexed LNG."*

In response to a BCUC Information Request about what the new high case should be the IPPBC responded[124]:

> *"A new high case could be the fossil fuel price assumptions from the latest International Energy Agency's ("IEA") World Energy Outlook (WEO) 2008, to be found on page 68 of the WEO 2008 (Table 1.4). Forecasted prices for US gas imports are expected to be $12.78/MMBtu in 2010 rising to $13.20/MMBtu in 2015, $14.75/MMBtu in 2020 and $16.13 in 2030 (all prices in constant 2007 U.S. dollars)."*

As noted above, BCH's natural gas price outlook sets out the probabilities of the low, mid and high case forecasts. Since the Assessed Probability of the High Case, 53%, is greater than for the Base Case, 44%, and much higher than the Low Case, this serves to confirm the IPPBC's evidence that BCH's High Case should be its Base Case. Although the increases in natural gas prices for the next 20 years will not be identical to those shown in Exhibit B-87, they will be far more indicative of future prices when the world economy recovers than the 1.5% business as usual approach taken in the Base Case. The new BCH High case should be the IEA "World Energy Outlook (WEO) 2008".

For all the above reasons, the IPPBC specifically and respectfully submits that the BCUC should reject BCH's natural gas price forecast.

7. Renewable Energy Credits

Renewable energy credits are a relatively new phenomenon that will have an impact on any comparative analysis of the cost of energy from IPP projects, industrial generation that is sold to BCH e.g. Bio Energy Phase 1, Power Smart, BCH Resource Smart projects, new BCH projects such as Site C, Burrard or system optimization RECs are a commodity that have value as indicated in Appendix H to the Application, "Global Energy's Renewable Energy Market Analysis Report".

[123] Exhibit C17-5, page 2 of "Testimony of Stephane Landry, Brookfield Power Corporation, on behalf of the Independent Power Producers of B.C."
[124] Exhibit 17-6, IPPBC response to BCUC IR 17.3

The challenge is not only to assess the value of RECs for comparative analysis but also to determine whether RECs exist that can be re-sold by BCH. The assumption being that BCH in its 2008 Clean Power Call will require IPPs to include any RECs from their IPPs in their bid prices. This will have the effect of making the bid price look higher than it actually is because it doesn't take into account the revenue that will accrue to BCH if it sells the RECs.

As a new field it is still evolving but it isn't fraught with as much uncertainty as some interveners were postulating through cross examination. In basic terms, there is move afoot in certain jurisdiction in the U.S. to increase the amount of renewable generation that in practice is distinct from pricing carbon dioxide as a pollutant. The BCH witnesses were very helpful in providing evidence about the distinction including the following[125]:

> *"Q: ... And in my mind at least, and certainly correct me if I'm wrong, the concept of RECs is in a sense tied to the renewable portfolio standards that certain utilities have, and that the concept of carbon offsets is something different again. Is that correct or have I got it all mixed up?*
>
> *A: That's correct. And I might describe a little bit about these prices that show up on Figure 4-5 ultimately impact my forecasts of REC prices. So the concept that we're dealing with here is that if somebody builds a renewable plant, and we're pretty much talking about wind because there's a lot of wind renewable and we need a lot of renewable. So he's going to build a wind plant. They could just build that, sell it into this market. We really call this kind of like a brown market. And they could get this price. The way they designed this, we think they could get this price.*
>
> *And they might also get some capacity payment because, depending on what you believe about effective load-carrying capability of wind plants, maybe they could contribute something towards your resource adequacy needs.*
>
> *So, the plants could get these prices, maybe some capacity prices, but you say, "Well, yeah but what is it going to cost me to build this plant?"...*
>
> *They're not going to be fine – well, they're not going to be financed, is the point, unless they can come up with another source of revenue, and that source of revenue now is being derived by a requirement by these many states that people meet RPS goals. And if they have to pay more to meet these goals, they do. So what we – that determined the price of the RECs will be the difference between the revenues they get from the capacity and these energy prices, and what the revenue requirement is, and that's going to be setting the price of the REC.*
>
> *A: And if it would be helpful, I can contrast that with an offset system, which is something very different, as Mr. Austin indicated.*
>
> *An offset system, under a cap and trade program, is intended to obtain verifiable, certifiable reductions below business as usual in sectors that are not covered under a cap and trade program. And the important thing to remember with an offset system is, if you are – if you need to preserve the integrity of the cap, of covered sectors, you need to make sure that the reductions occurring in non-covered sectors actually could not have*

[125] TR, V9, pages 1596 to 1599

occurred under business as usual. So as a result there's a number of sort of complex considerations including this additional question. Would it have occurred? And different tests that are applied. And this is a matter that, in – currently in the U.S. and debates over this, there is a lot of concern that you need to prove very carefully that they are additional, the offsets are additional to what business as usual would have been. Otherwise, you sacrifice the integrity of the cap.

Completely different from a REC system, which is, as were discussing, more a matter of subsidizing and thereby promoting renewable energy standards. They occur – they can occur side by side, but often in practice the policy decision has been made to keep them separate and not to allow overlapping, because you want to avoid double-counting.

Q: And while you're on the cap and trade system, under the cap and trade system, does the cap ratchet down over time?

A: It can, and it typically does, in practice.

Q: And the reason for that is because if it didn't ratchet down, you wouldn't have a continuous net reduction in the production of GHGs, is that correct?

A: That's right."

As indicated in the first paragraph under this heading, RECsl must be taken into account when a comparative analysis is done of various costs. As an illustration in cross examination, the IPPBC explored the impacts that RECs will have on BCH's ability to receive a premium price for electricity that has a corresponding REC. The following is an extract from some of that cross examination:[126]

"Q: And correct me if I am wrong, the reason for doing that is because the renewable IPP electricity, in accordance with what Mr. Lauckhart has told us, would probably be the premium priced electricity, or, instead of selling electricity, you would attempt to sell the REC. Is that correct?

A: That's right. Yeah so what we have in B.C. so far is – really haven't been exactly how they're going to measure the clean portfolio standard, but we understand it to be a generation standard. And so of what we produce in the province, 90 per cent of it is supposed to remain to be clean. Large hydro qualifies as clean. So that's what we'd be doing within the province. If we could then optimize our revenues by selling the RECs with the surplus energy into the U.S. market, and receive more revenues to offset our domestic costs, we'd do that."

In the Application at page 4-25 BCH says:

"BC Hydro's portfolio analysis in Chapter 5 includes the estimated incremental revenue that would result from the sale of the clean or renewable electricity from the BC Hydro system. The incremental price forecast that was used for estimating the revenues is provided in Figure 4-7. The BC Hydro scenarios were selected in the lower half of the Global Energy forecast reflecting the uncertainty of the ultimate price threshold that may result in each receiving jurisdiction before the local utilities were allowed to reduce their RPS obligations because of rate impacts."

[126] Exhibit B-1, page 4-21, Figures 4-5 and 4-6

As set out in the BCUC 2006 LTAP Decision the IPPBC is opposed to the use of portfolio analysis for long term planning[127] because the pricing data is not accurate enough to provide meaningful comparisons. The BCUC did not agree with the IPPBC's position noting in Order N. G-96-04 it said[128]:

> *"The Commission Panel does not expect that the determination of "target ranges" will be supported by portfolio analysis; however, preliminary portfolio analysis is not precluded. Moreover, the Commission Panel does not expect that the determination of "target ranges" will be supported by estimates of costs beyond "planning estimates". Estimates need to be prepared with the consideration of the intended use, that is, to support "target ranges". For specific projects, a suggested confidence range is plus or minus 35 percent. For certain resource types, particularly those that do not include specific projects, planning estimates may have confidence ranges exceeding plus or minus 35 percent."*

Irrespective of the IPPBC's continuing concerns about pricing data and portfolio analysis, the IPPBC's position is that BCH should use the mid range of the Global Energy REC Forecast[129] and not the low end. The low end ranges from U.S. $11 to $18 per megawatt hour and the high U.S. $57 to $62 from 2010 to 2020. In preparing its probability analysis of the Low, Base and High Cases for natural gas BCH's consultant Global Energy provided support for the IPPBC's position[130]:

> *"In assessing the relative probabilities of the Low and Base cases, only one factor distinguished the two scenarios – the assumed levels for achieving renewable/Energy Efficiency ("EE") state mandates in the WECC. (To reiterate, the Base Case assumes current targets are met and the Low case assumes nearly three times the number of MW are built as in the Base case, i.e. 34,500 MW versus 11,000 MW.) All of our experts concluded that the probability of achieving more than three times the state mandates for renewables/EE during the forecast horizon was 5 percent or less, thus establishing a low probability for a Low gas price forecast. The consensus of Global Energy's team is that the probability for the Low forecast is 3%."*

If BCH is using the Base Case for its natural gas price forecast it should be using the mid range of Global Energy's REC forecast. If it is using the low range of this REC forecast then logically it should, as advanced by the IPPBC, be using the High Case natural gas price forecast because the fewer the number of renewable MW that are built, the greater the demand for natural gas which translates into higher prices.

8. Greenhouse Gases and Price Forecast

The IPPBC submitted its own Greenhouse Gas Price Forecast that was prepared by Dr. Mark Jaccard. The cost of carbon dioxide pollution is not going to go away and is not someone else's problem. The Province of B.C. has brought in legislated targets[131] for the reduction of this pollution and a Report from the B.C. Climate Action Team, which was appointed by the Government, says[132]:

> *"As the government pointed out in its 2008 Speech from the Throne, every molecule of carbon dioxide emitted into the atmosphere matters. So does every molecule not emitted.*

[127] Pages 89 and 86-87
[128] BCUC 2007 LTAP Decision, page 87
[129] Exhibit B-1-1, Appendix H
[130] Exhibit B-1-1
[131] **Greenhouse Gas Reduction Targets Act**
[132] Exhibit B-4, BCH response to IPPBC IR 2.6.1, Attachment 1, page 10 of 45

> *So, even on a global scale, British Columbia's actions are important. They contribute to the efforts of people around the world who are acting today to prevent the problem from growing even worse."*

Dr. Jaccard was brought forward by the IPPBC to give his global and Canadian perspective on GHG pricing. As evidenced by his resume and as a member of the federally appointed National Round Table on the Environment and the Economy he is uniquely positioned to do so. Dr. Jaccard's evidence on GHG pricing is very short:

> *"Among other things, I am a member of the National Round Table on the Environment and the Economy. In my view if the Government of Canada is to reach its goal of long-term (2050) national emission reduction targets for greenhouse gas (GHG) the required emission prices for CO2e are likely to be in the range suggested by the table below:*

Table ES 1: Greenhouse gas price simulated in this report ($2005 / tonne CO_2e)

	2011-2015	***2016-2020***	***2021-2025***	***2026-2030***	***2031-2035***	***2036-2040***	***2041-2045***	***2046-2050***
Greenhouse Gas Price	*$15*	*$115*	*$215*	*$300*	*$300*	*$300*	*$300*	*$300*

> *My view is based on the attached report entitled "Draft Report Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy; A Sectoral and Regional analysis" dated July 1, 2008 which was prepared by J&C Nyboer for the National Round Table on the Environment and the Economy"*

He was not directly involved in the preparation of the referenced report but was instrumental in developing, over a number of decades, the CIMS model that underlies the report. Because of his unique experience, the GHG prices set out in Dr. Jaccard's evidence should be used in preference to those set out in the Application[133] and used in it e.g. Figure 4-5[134] and outlined on page 4-13 to 4-14 of the Application. If the assumption that there will be about a 60 per cent reduction in Canadian and U.S. greenhouse gas emissions below their 2008 levels by the year 2050 is increased to for example 80 percent, the prices look like they will be higher[135]

On cross examination by BCH Dr. Jaccard said:

> *"… The carbon pricing of an absolute cap and trade system, to hit that target by 2050, or a carbon tax that did the equivalent amount, would lead to this outcome in the marketplace without any government – additional government involvement of any kind whatsoever. And the reasons are obvious. I mean, if you're driving your economy down toward negligible emissions compared to where they are today, big things have to happen in all the different end use sectors. And in space heating, you can't be burning oil or natural gas for space heating in a significant way.*
>
> *So what are you going to use? You're going to use biomass, hydrogen or electricity, and electricity tends to win out because we move towards zero emission electricity generation. It's expensive but it's relatively low cost compared to other zero – other options for getting to low emissions. And I explained this in some detail in response to an information request."*

[133] Exhibit B-1-1, Appendix G1
[134] Exhibit B-1, page 421
[135] TR, V12, page 2116

The impact of the GHG prices estimated by Dr. Jaccard will be to increase the demand for electricity through fuel switching. However, fuel switching is not reflected in the Application except to a minor extent in the oil and gas sector[136].

For all the above reasons, the IPPBC specifically and respectfully submits that the BCUC should reject BCH's GHG price forecast.

9. Other

9.1. Threshold for Major Project Applications

The IPPBC does not agree with BCH's proposal to submit to the BCUC projects with a capital value in excess of $50 million for approval under section 44.2(1)(b) of the Utilities Commission Act. The appropriate section is section 45 where application is made for a certificate of public convenience and necessity. Under section 44.2(1)(b) the BCUC can only accept or reject a schedule or part of it. This limits its discretion to make selective improvements or modifications. Time sensitive projects may be bundled together with projects that are not in the public interest which may distort the review process. The IPPBC's concerns about this threshold are a case in point. BCH has embodied its threshold proposal in a much broader Application. The BCUC can reject all or parts of the Application but it can't say that the threshold should be $55 million and not $50 million.

The IPPBC also does not agree with BCH's proposal to bring forward projects with a value of $50 million or more where BCH is still seeking approval of its own board. The IPPBC does not want to commit scarce resources to examine projects that BCH's Board of Directors hasn't even approved.

For the above reasons, the IPPBC specifically and respectfully submits that BCUC should reject BCH's proposals with respect to submission of projects with a capital value in excess of $50 million in accordance with section 44.2(1)(b) of the Utilities Commission Act...

9.2. Proposed Capital Plan Review Process

The IPPBC has no objection to the proposal to file capital plans bi-annually as part of its future RRAs provided that for projects over $50 million, certificates of public convenience and necessity are still made.

9.3. Contingency Resource Plan

In an Information Request[137], the IPPBC asked how this project could be included when it would take 10 to 12 years to develop. A contingency resource plan is supposed to include resources that can be brought on in the short term to cover unexpected events. It is not, as suggested in BCH's response to the Information Request, a project development list.

9.4. LTAP Filing Cycle

[136] TR, V4, page 470 to 471
[137] Exhibit B-12, IPPBC response to BCH Information Request 3.20.1

The IPPBC does not agree with BCH's proposal to file its long term acquisition plans 2 years from the date of receipt of the BCUC's decision on the previous application. This will result in a 3 year review cycle at a time when the demand for electricity is likely to significantly increase because of fuel switching caused by GHG related legislation and policies.

For the above reasons, the IPPBC specifically and respectfully submits that the BCUC should reject BCH's proposal for changing the date for filing its long term plans.

10. Matters on Which the Commission Panel Requests Submissions in Argument

1. Section 44.1(7) of the Act states that the Commission may accept or reject a "part" of a public utility's plan. In light of the fact that "part" is not a defined term under the Act, the Commission Panel seeks clarification of the views of the Parties as to what might constitute a "part" of the 2008 LTAP. In their submissions the Parties should address the ability of the Commission to reject a part of a public utility's plan while still accepting it as a plan.

   In the absence of any instrument that defines "part", the IPPBC respectfully submits that the BCUC take a "reasonable person" approach to its interpretation. If a sufficient number of parts or a part that goes to the core of the plan are rejected with the result that the plan becomes meaningless it must be rejected. It is up to the BCUC to exercise its judgment as to when the "meaningless" threshold is crossed and the IPPBC can think of no hard and fast rule it can propose.

2. In light of the parameters for assessing "cost effectiveness" as spelled out at Section 4 of DSM Regulation Order M271, to what degree, if any, is the Commission's discretion fettered in its review of the utility's DSM proposals?

   See the detailed discussion of "DSM cost-effectiveness – using the TRC and RIM together", in Section 3.2. With an understanding of how the TRC and RIM are related, the Commission will realize that it cannot directly compare demand-side programs to supply-side options without seeing the RIM unit costs, because supply –side prices from IPPs are, in fact, ratepayer impact costs, not total resource costs. They are not comparable to TRCs. They are most comparable to RIM costs.

   The BCUC does seem to be fettered somewhat by the Minister's DSM Regulation in that it cannot reject a DSM program on the basis of its RIM cost alone.

   However, the BCUC still has considerable discretion. After seeing the comparisons between RIMs and TRCs, the BCUC can ask for more detail, it can ask for the data to support the assumptions for free riders, persistence, cross effects, etc. It can question the magnitude of the profit premiums required to induce participants. It can ask for reconsideration or amended designs.

3. Section 44.1(8) of the Act states that "in determining under subsection (6) whether to accept a long-term resource plan, the commission must consider (a) "the government's energy objectives", which are defined as including "to encourage public utilities to reduce greenhouse gas emissions". In light of this would the approval by the Commission of FNU3 contravene such an instruction?

   If filed under 44.1(8) then in the absence of any other viable alternatives, the IPPBC's answer is yes. The transmission option from the GMS switchyard to Fort Nelson appears to be a viable option but it hasn't been studied in a material way. Absent this work, it would be premature for the BCUC to come to the conclusion that the government's objective of encouraging public utilities to reduce greenhouse gas emissions isn't applicable with respect to Fort Nelson. The BCUC should not be interpreting Section 44.1(8) in a manner that precludes all forms of fossil fueled thermal

generation. For instance in a remote community that is not linked to the grid, there may me no choice but to install this generation.

The IPPBC wishes to add that without ministerial "recognition" FNU3 is not "clean" for the purposes of section 64.02 of the Utilities Commission Act[138]. There is a discussion in the Transcript[139] about the goal that 90% of the electricity in B.C. be generated by the persons to whom section 64.02 is applicable from clean or renewable resources. It is not clear the circumstances under which BCH would exceed this goal if it brings on new fossil fuel thermal generation including FNU3. It depends on the operation of Burrard.

The IPPBC notes that BCH states that FNU3 was filed under section 44.2.3.

4. Does BC Hydro's Fort Nelson Resource Plan comply with the requirements of section 44.1(2) of the Act? In making its determination in respect of that Plan, on what basis, if any, should the Commission Panel grant the exemption set out in section 44.1 (9) (a)?

This is a situation where there is no easy answer because events appear to have overtaken the plan. As indicated under "Fort Nelson and the Demand for Electricity by the Oil and Gas Sector", the IPPBC's position is that BCH's electricity demand forecast for the B.C. oil and gas sector needs is deficient. Although it is not the only sector driving the demand for electricity upward in Fort Nelson, it is the most important.

Because of this, the IPPBC would normally submit that the demand forecast for the Fort Nelson area be specifically rejected as part of the plan. However, the Section 5 Inquiry Terms of Reference, section 7(c), explicitly require an examination of transmission expansion in the northeast region of B.C. One way or another the electricity requirements for the oil and gas sector in the Fort Nelson area are going to be thoroughly examined and the deficiencies in the plan are academic.

5. The subject of BC Hydro's contemplation of the potential demand arising from electric vehicles was canvassed at some length in the review to date (T4:470-74), with BCH's position stated as essentially being one of "monitoring developments". Shortly thereafter BCH announced its participation in a BC Government led program in respect of electric vehicles, and BCH's engagement of consultants, pursuant to a call for proposals, to detail the necessary actions for deploying electric vehicle charging infrastructure, with a report to be filed by the end of April 2009. Given these developments, should the evidentiary record be re-opened to admit this evidence, and, if so, should Parties be given the opportunity to examine it and make submissions as appropriate, and if so, by what process?

The IPPBC respectfully submits that the evidentiary record be re-opened and the BCH witnesses that provided responses to the IPPBC's questions about why the demand for electric vehicles is not included in the load forecast be asked to explain the apparent differences in their evidence and BCH's subsequent actions. This could be done through written submissions with BCH first providing the explanation and then any intervener that wanted to, replying in writing. There would be no further right of reply of any party.

6. In order to determine if BCH can rely on Burrard for planning purposes for 900 MW of capacity and either of 600 GWh, 3,000 GWh or 6,000 GWh of energy would the Commission have to find

[138] See also Exhibit B-1-1, Appendix B-3
[139] TR, V6, pages 1011 to 1020

that the capital expenditures in excess of $300 million for each scenario that AMEC stated would be required (Exhibit B-1-1, Appendix J1, p.94) were cost-effective?

The IPPBC has set out its detailed comments about this topic under the sub-heading "●●. The short answer is no it can't because the AMEC report says:
*"**Cost Implications of Scenarios 1, 2 and 3**: Burrard TGS is NOT at present in a condition consistent with Scenarios 1,2 and 3 set out above where 900 MW of generation capacity is consistently critical over the next twenty years (an N+0, where N=6" role). Without significant investment in detailed inspections in the next two years and procurement of critical spares, extended single unit outages (and possibly multiple unit outages) due to major critical equipment failures, is a reasonable position in the next 2 to 5+ years (depending on the scenario)"*

7. In Section 4.3 of Exhibit B-10, BCH proposes a threshold for major project applications. Parties are requested to make submissions on BCH's definition of a threshold by addressing situations where a number of projects might constitute a program which in total would exceed the threshold but the elements of which would not individually exceed the threshold.

There is no hard and fast rule that can be established to prevent "project" creep. The BCUC and interveners have to be diligent to prevent it. Section 45 of the Utilities Commission Act remains as the ultimate deterrent to behavior of this type. While the IPPBC wants to take a practical approach to BCH's capital expenditure approvals, it doesn't want to see it abused.

11. Response to BC Hydro Argument

The IPPBC only wishes to comment of two portions of BCH's argument.

The IPPBC supports BCH's arguments about fuel switching from electricity to natural gas. The IPPBC's own expert witness pointed out that in a carbon reduction driven world, there must be a switch from fossil fuels to toward zero emission electricity. Suggestions that by burning natural gas, BCH will have more renewable electricity for export are not supported by any practical evidence, Buyers are supposed to step forward and the transmission paths to be available to make these transactions viable. No consideration was given as to whether the supposed benefits in terms of the buyer's GHG reductions could be verified over the life of the electricity sales agreement and to whom these benefits under GHG legislation would accrue. It is just all supposed to happen.

The IPPBC supports, as set out in section 6.3.3 of BCH's argument, BCH's 3,000 GWh/year pre-attrition target for the 2008 Clean Power Call ("Call"). The IPPBC anticipates that on further analysis of matters such as the insurance requirements of SD 10 and Scenario 2 of Burrard, BCH will as part of its approval of the contracts awarded pursuant to section 71 of the Utilities Commission Act will seek an increase in the Call volume.

The IPPBC does not support and specifically and respectfully requests the BCUC to reject the 2,100 GWh/year post-attrition target. Unlike thermal projects, renewable projects have unique siting requirements that may not be known until some time after a contract is

awarded and which may have an adverse impact on a project's financial viability. Attrition has to be taken into consideration when the Call size is set.

Under these circumstances, setting the Call is not an exact science. Neither is projecting DSM savings or establishing BCH's load forecast.