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December 15, 2008

Via Email

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: BC Hydro's Application to Amend Section 2.1 of Rate Schedule 3808 ("RS 3808") Power Purchase Agreement - Project No 3698531

Please find attached FortisBC Inc.'s submission of evidence in the above noted application.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

British Columbia Hydro and Power Authority
An Application to Amend Section 2.1 of
Rate Schedule 3808 ("RS 3808")
Power Purchase Agreement ("PPA")

Evidence of
Dan Egolf

on behalf of
FortisBC Inc. ("FortisBC")

December 15, 2008

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BACKGROUND

In its application (the "**Application**") to the British Columbia Utilities Commission (the "**Commission**") pursuant to Section 58(1) and (2) of the *Utilities Commission Act* (British Columbia) for approval to amend Section 2.1 of the PPA, British Columbia Hydro and Power Authority ("**BC Hydro**") alleges that the export activities of certain FortisBC customers who have self-generation capabilities will oblige BC Hydro to provide incremental energy to FortisBC pursuant to the PPA, at embedded cost rates, to replace the exported energy. BC Hydro alleges further that to supply such incremental energy BC Hydro will incur an "opportunity cost". BC Hydro estimates that the value of this "opportunity cost" will be roughly $16.7 million annually (see Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008, p. 4).

BC Hydro describes certain key assumptions on which its $16.7 million estimate is based in the following footnote which appears on page 4 of Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008:

> Assuming energy for sales by the City of Nelson of 28 GWh and Celgar Pulp and Paper of 350 GWh is supplied by BC Hydro under the PPA and calculated as the difference between the PPA energy price to FortisBC of 2.952 cents/kWh and BC Hydro's long term opportunity cost of new supply of 7.36 cents/kWh, as represented by the Tier 2 energy price of RS 1823.

BC Hydro reiterates and expands on these assumptions in its responses to certain of the Commission's Information Requests (see Exhibit B-5, BC Hydro responses to Commission IR 1.7.1, Commission IR 1.7.1.1 and BCOAPO IR 2.3.2).

EVIDENCE SUMMARY

FortisBC has developed evidence to demonstrate, on the basis of assumptions different from those used by BC Hydro in the Application (and which are, in FortisBC's submission, more reasonable in the circumstances), that:

(a) BC Hydro may not necessarily incur any material "opportunity cost" in connection with its provision of incremental energy under the PPA to replace energy exported by FortisBC customers; and

(b) BC Hydro may be able to earn a profit from its provision of any such incremental energy.

DIRECT EVIDENCE OF DAN EGOLF

I am employed by FortisBC in the capacity of Manager, Resource Planning. In the course of my duties, I am responsible for FortisBC's long-term and next-year power supply arrangements. I am authorized on behalf of FortisBC to give the following evidence in this proceeding.

FortisBC's analysis of potential impact of provision of replacement energy

(a) Cost to BC Hydro of replacement energy

FortisBC does not believe that the long-term cost of new supply, used by BC Hydro to estimate its "opportunity cost" of providing replacement energy (see BC Hydro response to Commission IR 1.7.1.1), is a realistic proxy. FortisBC believes it is more appropriate to use the forecast cost of non-firm energy, since non-firm energy more closely resembles the energy BC Hydro might require to replace any energy exported by FortisBC customers. That is because non-firm energy is supplied without a capacity component. (BC Hydro has confirmed that City of Nelson exports do not change the magnitude of the capacity reservation held by BC Hydro on its system (see BC Hydro response to FortisBC IR 2.6.1).)

In its 2008 Long Term Acquisition Plan (the "2008 LTAP"), BC Hydro has determined a "2008 Electricity Price Forecast" which it has used "to determine compensation for non-firm energy produced by successful bidders in the Clean Power Call" (see page 4-21 of the 2008 LTAP). A copy of Chapter 4 (Market Assessment) of the BC Hydro LTAP is attached as Attachment 1. Figure 4-6 on page 4-21 of the 2008 LTAP indicates that BC Hydro's own mid-range average hourly price forecast for the next several years is about $45/MWh.

(b) Price of power sold to FortisBC under the PPA

Attached as Attachment 2 is a document showing that FortisBC's forecast of the combined cost of its energy and capacity purchases from BC Hydro under the PPA would be approximately $39.6/MWh (before taking into account any rate increase for 2008 or 2009).

(c) FortisBC's calculation (before adjustment)

Before making the necessary adjustments described below, FortisBC calculates the difference between the cost to BC Hydro of replacement energy purchases and the price of power sold to FortisBC to be as follows:

$45/MWh − $39.6/MWh = $5.4/MWh

Then, applying BC Hydro's own estimate of combined annual energy supply sales to the City of Nelson and Zellstoff Celgar Limited Partnership (being 378,000 MWh) yields the following estimated annual cost to BC Hydro (before adjustment):

$5.4/MWh × 378,000 MWh = $2,041,200

(d) Application of further adjustments

(i) market trading efficiency factor

FortisBC believes that by making prudent buying decisions, BC Hydro could replace any requisite incremental energy at pries equivalent to, if not better than, the embedded cost price at which it would be selling energy to FortisBC under the PPA.

First, it should be noted that the $45/MWh figure is an average amount. Actual prices will, obviously, vary from the average. Moreover, BC Hydro is generally regarded as one of the most skilled and accomplished energy traders in North America. Accordingly, FortisBC believes that BC Hydro can reasonably be expected to achieve at least a 10% efficiency advantage over the average price.

(ii) anticipated rate increase

FortisBC believes it is reasonable to anticipate about a 7% cumulative rate increase for power deliveries under the PPA in 2008 and 2009.

(e) Adjusted FortisBC calculation

FortisBC believes the following calculation more accurately estimates the "cost" to BC Hydro of replacing energy exported by FortisBC customers:

($45/WMh × 0.90) – ($39.6/MWh × 1.07) = ($1.9/MWh)

Again applying BC Hydro's estimated sales to the City of Nelson and Zellstoff Celgar Limited Partnership (being 378,000 MWh) yields the following estimated annual profit to BC Hydro:

$1.9/MWh × 378,000 MWh = ($718,000)

Provision of operating information

FortisBC is prepared to work with BC Hydro to ensure that BC Hydro is not inadvertently reserving more capacity on the BC Hydro system than is necessary to meet its obligations under the PPA.

City of Nelson Power Supply Agreement

Attached as Attachment 3 is a copy of the Agreement for the Supply of Electricity Wholesale Service between FortisBC and the City of Nelson dated as of the 1st day of November, 2004.

ATTACHMENT 1

2008 Long Term Acquisition Plan

BC hydro

Volume 1

Chapter

4

MARKET ASSESSMENT

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4.1 Introduction

This Chapter of the Application examines the major external influences of both government policy and regulatory initiatives, and the power industry marketplace, in BC Hydro's long-term resource planning since the 2006 IEP/LTAP. More specifically, as part of Step 4 (see Figure 1-1) in the 2008 LTAP update, BC Hydro assessed:

- The developing GHG regulatory environment. Section 4.2 reviews and summarizes relevant GHG legislative and policy developments since the 2006 IEP/LTAP Decision, and sets out an updated GHG price forecast for 2008-2050;

- Natural gas (section 4.3) and electricity prices (section 4.4). In the intervening two years since the 2006 IEP/LTAP, natural gas and electricity markets are exhibiting upward trends. Fuel prices, particularly natural gas, are a major driver of WECC wholesale electricity market prices and they strongly affect the economics of new generation resources that may be considered by utilities; and

- The RPS requirements in the U.S. portion of WECC, and the eligibility of B.C.-based renewables supply under various U.S. state RPS, in section 4.5. A forecast of the incremental value of the RECs associated with renewable electricity generation is provided in that section.

BC Hydro has improved the methodologies it applied in its analysis of the relevant markets and related factors that impact its long-term resource planning. In preparing its GHG, natural gas price, and clean and renewable market forecasts, BC Hydro elicited the services of third party experts, and in particular with respect to both the GHG and natural gas price forecasts, asked these experts to assign probabilities to those forecasts. Natsource prepared the 2007 Greenhouse Gas Offset Forecast Report for BC Hydro, December 1, 2007 which appears at Appendix G1 to this application. Natsource assigned probabilities to the main GHG policy scenarios in its memorandum entitled "Probabilities for scenarios in Natsource's 2007 Greenhouse Gas Offset Forecast Report", attached as Appendix G3.

Global Energy prepared the report entitled Natural Gas Price Forecasts for BC Hydro that is included at Appendix I. As described in section 1.2.6, Global Energy utilized three internally consistent, fundamentals-based scenarios of future market conditions it previously

developed for the CEC as part of the CEC's IEPR process. As a result of Global Energy's development of a High Gas Price Forecast and assignment of probabilities to the three Global Energy natural gas price forecasts, in the 2008 LTAP BC Hydro has not relied on the three natural gas price scenarios previously used in the 2006 IEP/LTAP, namely its internally generated High Gas scenario, the U.S. Energy Information Administration (**EIA**) forecast and the Confer Consulting Long Run Marginal Cost case. BC Hydro has also discontinued the use of an equally weighted average of forecasts used in its analysis. In addition, for the first time the electricity price forecast incorporates GHG offset costs.

4.2 Greenhouse Gas Offset Price Forecast

4.2.1 Introduction

Utilities face two distinct sets of risks related to global climate change. One set, which is addressed in this section and Appendix G, are the financial risks associated with GHG regulatory actions. A second set, which will be addressed in the next LTAP in accordance with Directive 6 of the BCUC's 2006 IEP/LTAP Decision, are the risks associated with climate change itself, such as the physical impacts of climate change on electricity generation.

The 2006 IEP/LTAP recognized the potential for government-imposed costs associated with GHG policy. In the intervening two years, the B.C. Government and a number of U.S. states have implemented mandatory targets for GHG reduction. The Canadian Federal Government is currently in the process of introducing regulations under the *Canadian Environmental Protection Act*[45] (***CEPA***) to set mandatory GHG reduction targets and the U.S. Congress also plans to legislate GHG reduction goals. These legislative initiatives are expected to establish and influence the market price for GHGs through such regulatory mechanisms as emissions trading and GHG offset programs.[46] In turn, regulatory responses

[45] S.C. 1999, c.33.

[46] In this application, a GHG offset is considered a real, verifiable and additional reduction of GHG emissions, or removal of GHG from the atmosphere, that is established, approved or recognized by B.C. or Canadian regulation as an offset. The purpose of an offset is typically to achieve a cost-effective reduction of total GHG emissions by decreasing emissions from a source or activity not covered under emissions reduction regulatory programs and attributing (or crediting) the reduction to another, regulated source or activity. For example, reducing methane emissions from landfill sites may be considered an offset for a thermal generation plant if this activity is not already covered under an emissions trading program and is not required to occur under command and control regulations.

to limit GHGs are also expected to significantly affect the costs, market value and risk associated with the evaluation of electricity generation resource options by utilities.

This section provides an overview of the emerging regulatory and policy developments considered in the Natsource GHG price forecast, and the implications of those developments for the 2008 LTAP. The section is structured as follows:

- Section 4.2.2 provides a general overview of the key regulatory and policy developments in B.C., Canada and the U.S. subsequent to the finalization of the Natsource GHG price forecast report, dated December 1, 2007;
- Section 4.2.3 sets out the three policy scenarios used to frame the GHG price forecast and two sensitivity cases describing potential near-term policy outcomes influencing prices in B.C., and summarizes the results of the GHG price forecast scenarios and probability analysis; and
- Section 4.2.4 describes how the GHG price forecasts are incorporated into the 2008 LTAP analysis.

Additional details regarding GHG pricing assumptions, methodology and a comparison of BC Hydro's GHG price forecast to forecasts used by other electric utilities in integrated resource planning is found in the Natsource GHG price forecast report attached as Appendix G1.

4.2.2 GHG Regulatory and Policy Developments

BC Hydro retained Natsource to update the GHG price forecast prepared for the 2006 IEP/LTAP Application. Natsource reviewed developments in GHG regulatory policy in B.C., Canada and the U.S. (federal and state-level). Part II of the Natsource GHG price forecast report contains a description of the legislative and policy initiatives to limit GHG emissions. These GHG-related developments reinforce Natsource's and BC Hydro's view that a scenario in which the price of GHGs would be zero is not foreseeable. The remainder of this section updates these initiatives.

4.2.2.1 Canada - Federal Regulatory Framework

On March 10, 2008, the Federal Government announced further details of proposed GHG emissions regulations[47] to be enacted under *CEPA*. The March 2008 Regulatory Framework confirmed intensity-based GHG reduction targets of 18 per cent by 2010, with a 2 per cent continuous improvement every year after that, for regulated industries such as electricity generation produced by combustion. Four compliance mechanisms are available: in-house reductions, contributions to a Technology Fund,[48] acquiring offsets[49] and receiving credit for early action. From 2010 to 2012, the contribution rate for the Technology Fund would be $15 per tonne of CO_2e. In 2013, the contribution rate would be $20 per tonne. Thereafter, the rate would escalate yearly at the rate of growth of nominal GDP to 2017. Environment Canada would administer the offset system and will approve project protocols, register projects submitted by proponents, certify the reductions and issue offset credits. Guidance documents for protocol developers, project proponents and verification bodies will be published during the summer of 2008.

The federal GHG emissions regulations will also set a coal-fired generator standard equivalent to CCS. The regulations will apply to coal-fired generators coming on stream in 2012 or after, and will come into force in 2018. The GHG emission regulations are expected to be published in the *Canada Gazette* later this year, and the regulations finalized in 2009 to come into force on January 1, 2010.

4.2.2.2 Province of British Columbia

There have been several B.C. Government legislative developments:[50]

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[47] Environment Canada, "Turning the Corner - Regulatory Framework for Industrial Greenhouse Gas Emissions," March 2008. http://www.ec.gc.ca/doc/virage-corner/2008-03/pdf/541_eng.pdf.

[48] Contributions to the Technology Fund would be limited to 70 per cent of the target in 2010, falling to 65 per cent in 2011, 60 per cent in 2012, 55 per cent in 2013, 50 per cent in 2014, 40 per cent in 2015, 10 per cent in 2016 and 10 per cent in 2017. No further contributions would be accepted after 2017. The research and development component, which would focus on projects aimed at supporting the creation of transformative technologies, would be limited to 5 Megatonnes each year, also ending after 2017.

[49] This includes unlimited access to domestic (made in Canada) offset projects and certain credits from the Kyoto Protocol's Clean Development Mechanism (**CDM**). Access to CDM credits for compliance purposes would be limited to 10 per cent of each firm's total target.

[50] Additional GHG-related legislative developments not described in this section are the *2008 Greenhouse Gas reduction (Renewable and Low Carbon Fuel Requirements) Act*, and the *Greenhouse Gas Reduction (Vehicle Emissions Standards) Act*. The former Act creates a regulatory framework to enable the Province to create
Footnote continued on next page.

- On January 1, 2008 the *Greenhouse Gas Reduction Targets Act* (***GGRTA***) was brought into force.[51] *GGRTA* sets into law B.C.'s GHG emissions target of at least 33 per cent below 2007 levels by 2020, and at least 80 per cent below 2007 levels by 2050. Interim GHG targets for 2012 and 2016 are to be set by the end of 2008;

- The Province of B.C. has joined the WCI, a partnership of seven U.S. states and the provinces of B.C., Manitoba and Quebec. This commitment includes participation in the design and implementation of a GHG emission trading system.[52] On May 29, 2008, the *Greenhouse Gas Reduction (Cap and Trade) Act* (***GHG Cap and Trade Act***),[53] received Royal Assent, but comes into force by regulation. The purpose of the *GHG Cap and Trade Act* is to enable the reductions of GHG emissions through a cap-and-trade system. The *GHG Cap and Trade Act* establishes compliance obligations for regulated operations in B.C. to determine GHG emissions, ensure compliance is met through the retirement of sufficient compliance units, and report emissions and compliance actions. The *GHG Cap and Trade Act* establishes three mechanisms for compliance (compliance units) - (1) allowances, (2) reductions and (3) recognized compliance units from other cap-and-trade systems - and sets out requirements for a tracking system for compliance units. Virtually all of the details are left to regulations. For example, among other things, regulations are to establish: (1) the regulated operations; (2) the method of allocating allowances to entities (e.g. free of charge or through auctions); (3) the compliance units, and in particular what the geographic scope of out-of-Province compliance units will be; (4) the compliance unit tracking system; and (5) whether GHG emissions associated with imports are to be regulated. Pursuant to section 39(c), the B.C. Government may deem GHG emissions outside B.C. to be attributable to a regulated operation and "in relation to electricity, [deem] [GHG] emissions associated with generation and transmission of the electricity until the point at which the electricity is received by the British Columbia electricity grid to be attributable" to a regulated operation. The *GHG Cap and Trade Act* contemplates eventual linkage of the B.C. cap and trade system to other systems, such

renewable-content and low-carbon specifications for transportation fuel. The latter Act creates a new regulatory structure to reduce GHG emissions by requiring motor vehicle manufacturers to have their vehicle fleets meet a prescribed fleet emissions standard. Neither Act is relevant to the 2008 LTAP.

[51] B.C. Reg. 407/2007 (OIC 848/2007).

[52] British Columbia Office of the Premier, News Release: "B.C. Joins Western Regional Climate Action Initiative," April 24, 2007. http://www2.news.gov.bc.ca/news_releases_2005-2009/2007OTP0053-000509.htm.

[53] S.B.C. 2008, c.32.

as WCI. This is evidenced by the definition of "recognized compliance units" as units from another system that are recognized under the *GHG Cap and Trade Act* and by the provision that the compliance unit tracking system may be linked by regulation to another comparable system. The framework of the WCI GHG cap-and-trade system is expected by August 2008,[54] for implementation by partner jurisdictions by 2012;

- On May 29, 2008 the *Emissions Standards Act* received Royal Assent; section 2, the relevant section, comes into force by regulation. As set out in Table 1-2 in section 1.2.3, ~~Bill 31~~ *Emissions Standards Act* amends *EMA* as follows. Prescribed coal-fired generators will be required to capture and sequester GHG emissions from the combustion of coal. New electricity generation facilities, and prescribed expansions to existing facilities, that use fossil fuel other than coal will be subject to the "net zero" GHG requirement as soon as the *Emissions Standards Act* comes into force. Net zero GHG emissions means that such facilities must use offsets to balance their GHG emissions. Existing facilities that use fossil fuel other than coal will be given until 2016 to become net zero; and

- The Carbon *Tax Act* received Royal Assent on May 29, 2008, and comes into force on July 1, 2008. Pursuant to OIC No. 387,[55] the *Carbon Tax Act* is applicable to BC Hydro. The *Carbon Tax Act* imposes the revenue neutral carbon tax announced on February 19, 2008 as part of the B.C. Government's budget. The tax would apply to virtually all fossil fuels within the B.C., including natural gas, coal, diesel fuel, gasoline, propane and home heating oil. The level of the carbon tax has been set at $10 per tonne of associated CO_2 or CO_2e, emissions, starting on July 1, 2008. Natsource[56] confirmed that the proposed carbon tax does not undermine the assumptions made in the development of the scenarios or the GHG price forecast, because the carbon tax signals of $10 per tonne of associated CO_2 and the subsequent increase of $5 per year to $30 per tonne of associated CO_2 are for purposes of setting the rate of the carbon tax within B.C., not offsets or cap-and-trade compliance mechanisms. Pursuant to section 84 of the *Carbon Tax Act*, the B.C. Cabinet may with respect to a fuel or combustible that is

[54] Western Climate Initiative website. http://www.westernclimateinitiative.org/.

[55] Approved and ordered June 6, 2008.

[56] Refer to the Natsource report entitled "Addendum to Section 2(b) of Natsource's '2007 Greenhouse Gas Offset Forecast Report for BC Hydro' dated December 1, 2007", attached as Appendix G2.

the source of GHG emissions, provide for a regulation that exempts from the payment of the tax, or that refunds of all or part of the tax paid, subject to compliance obligations under the *Carbon Tax Act* and the new offset requirements for electricity generation under the *Emissions Standards Act*. Regulations prescribing the specific requirements of the *Carbon Tax Act* have not yet been introduced, and therefore BC Hydro has assumed in the 2008 LTAP analysis that it will continue to pay the carbon tax for all fossil fuel used for the generation of electricity at the three thermal generating facilities owned by BC Hydro – Burrard, the 46 MW Prince Rupert Generating Station and the 47 MW FNG and would pay the tax for any new carbon fuel based resource.

As described in Part II of the Natsource GHG price forecast report, a key question influencing the GHG price in B.C. is the extent to which the Province's forthcoming climate change legislative and regulatory program will be harmonized with the Canadian Federal Government's GHG policies and Regulatory Framework. Under section 10 of *CEPA*, when an instrument already exists in another jurisdiction (provincial/territorial) that achieves the same environmental outcome as a *CEPA* regulation, the provincial or territorial instruments apply instead of the *CEPA* regulation.[57] For this to occur, the Province/Territory enters into an equivalency agreement with the Government of Canada. The extent to which B.C. entities will be able to participate in Federal compliance mechanisms such as the Technology Fund and Federal offset system is unknown at this time, and may be dependent on Federal actions in relation to U.S. regulatory developments. B.C. could decide to maintain its participation in the WCI program and to meet its target independently, even after a Federal program has commenced.

4.2.2.3 U.S. – Federal Government and State Initiatives

The evolving interrelationship between the GHG policies of Canada and the U.S. at the Federal level is expected to significantly influence GHG prices faced by utilities in B.C. Several pieces of legislation have been introduced in the 110th U.S. Congress that would require mandatory GHG reductions and that would also establish an emissions trading program. These proposals include:

[57] For more information concerning Equivalency Agreements under the CEPA, refer to:. http://www.ec.gc.ca/CEPARegistry/gene_info/factsheets/fs_fi-equiv.cfm.pdf.

- Senator McCain's and Senator Lieberman's *Climate Stewardship and Innovation Act* (**S. 280**);
- Senator Lieberman's and Senator Warner's *America's Climate Security Act* (**S. 2191**);
- Senator Sanders' and Senator Boxer's *Global Warming Pollution Reduction Act*; and
- Senator Bingaman's and Senator Specter's *Low Carbon Economy Act* (**S. 1766**) among several others.

The Natsource GHG price forecast report at Appendix G1 provides a detailed review of recent U.S. Federal legislative direction and new proposals currently under consideration by the U.S. Senate and House of Representatives.

At the time of writing the Natsource price forecast report, the impact of S. 280 on GHG prices had been modelled by a number of organizations, and formed the underpinning of the price forecast. S. 280 sets moderately stringent targets of approximately 17 per cent above 1990 levels for electric power generation and other covered sectors between 2012 and 2019; approximately equal to 1990 levels between 2020-2029; and approximately 22 per cent below 1990 levels between 2030-2049. By 2050, the cap is set approximately 60 per cent below 1990 levels. More recently, S. 2191, introduced in October 2007, has received considerable attention. S. 2191 is a somewhat more stringent Bill than S.280, setting a cap of approximately 13 per cent above 1990 levels by 2012 and 3 per cent below 1990 levels by 2020 for electric power generation and other covered sectors. The cap drops to 24 per cent below 1990 by 2030 and 45 per cent below 1990 by 2040. Given the timing of the U.S. Federal election, it is not clear which Bill will be signed into law before 2009-2010.

Several WECC states have either adopted generation GHG emission performance standards and/or GHG emission mitigation requirements. For example, California[58] and Washington State[59] have established GHG emission performance standards that prohibit load serving entities from entering into long-term financial commitments unless base load generation complies with a GHG emission performance standard not to exceed the rate of

[58] California Senate Bill (**SB**) 1368.
[59] Washington State SB 6001.

emissions of a CCGT. Refer to Part II of the Natsource GHG price forecast report for further details with respect to California, Washington State and other WECC states.

4.2.3 GHG Price Forecast

The starting point in quantitatively evaluating GHG risk is to develop specific assumptions about GHG legislation that could plausibly be implemented over the lifetime of the resource investments being considered. Despite the high level of activity in policy and regulatory development related to GHGs, the specific form, and in some cases the timing, of many of these developments is highly uncertain. Consequently, the potential implications for electric resource economics and utility investment decisions is also highly uncertain. In consideration of this uncertainty and to provide more reliable data for its analysis, BC Hydro adopted a policy scenario approach to assess the impact of GHG regulation and GHG offset price variability.

BC Hydro's GHG price forecast considers two key drivers influencing GHG price, the stringency of regulatory policy (targets) and the flexibility of compliance mechanisms (supply/availability). Three scenarios were created by Natsource to describe the range of potential GHG policies for the years 2007-2050. These scenarios were not intended to predict specific outcomes, but rather, to provide reasonable upper and lower bounds for the GHG price forecast. Natsource applied its experience and knowledge of GHG policy and markets to assign a best estimate probability of occurrence for each of the three scenarios. In addition, given the recent legislative actions and announcements by the Province of B.C., two sensitivity cases were described for the near term 2007-2020, when B.C. may decide to pursue emission reduction programs, either on its own, or as part of a regional group such as WCI or WECC.

The various scenarios and sensitivity cases developed and applied by Natsource are described briefly below. In addition, Natsource estimated the probability for each of the three main scenarios and those probability assessments are included with the summaries that follow. Detailed descriptions of the scenarios are found in the Natsource GHG Forecast report at Appendix G1 and the rationale for the probability estimates is found in the Natsource report entitled “Probabilities for scenarios in Natsource’s “2007 Greenhouse Gas Offset Forecast Report for BC Hydro”, attached as Appendix G3.

The price scenarios are:

- "Price Cap" Scenario: Canada and the U.S. are outside of an international agreement and implement less ambitious GHG regulatory policies, including capped prices on GHG emissions, such as the Technology Fund of the current Regulatory Framework in Canada and less-stringent legislative proposals in the U.S., such as S. 1766's proposed price ceiling. The "Price Cap" scenario was considered least likely (15 per cent probability), since price caps were considered less likely to be acceptable because they could jeopardize the achievement of an emissions cap;

- "Linked Markets" Scenario: Canada and the U.S. establish more ambitious targets and link trading programs after 2015. Both countries join an international framework by 2020, with limited constraints on domestic and international offsets. The Linked Markets scenario was considered most likely (60 per cent probability); and

- "Made in North America-Aggressive Targets" Scenario: Canada and the U.S. establish more aggressive targets and link trading in 2012, but do not join an international regime. International offsets (outside of North America) are not allowed. The "Made in North America" scenario was considered second most likely (25 per cent probability),

The sensitivities affecting the B.C. region are:

- "WCI/WECC" sensitivity analysis: B.C. will meet its stated reduction targets as a participant in a WCI regional trading program starting in 2012. Eligible offsets would be created within the WCI/WECC region. The WCI/WECC sensitivity case was considered most likely for estimating GHG price in B.C. for the near-term 2012 – 2015; and

- "B.C. only" sensitivity analysis: B.C. will meet its stated reduction targets with legally binding hard caps, without using offsets or compliance instruments from outside the province. This B.C. only case was not considered likely, because the current activity of the WCI in developing a cap-and-trade system was considered more likely to influence GHG price in the near term, but is included for completeness to determine a potential high bound in B.C.

Table 4-1 summarizes the $/tonne GHG offset costs for the three scenarios. Table 4-2 summarizes the two nearer term price sensitivities that may impact B.C.

Table 4-1 Price Estimates for Planning Scenarios (CDN $ 2008)

Year		2010	2012	2015	2020	2030	2040	2050
Price Cap scenario ($)		14	14	18	18	18	18	18
Linked Markets Scenario	Price Range ($)	n/a	Canada: 14	Canada: 18	15 - 25	24 - 54	39 - 59	63 - 97
			US: 12-18	US: 11 - 17				
	Mid Point($)		Canada 14	Canada 18	20	39	49	80
			US 15	US 14				
Made in North America Aggressive Targets Scenario	Price Range ($)	n/a	16 - 24	24 - 47	35 - 57	65 - 84	112 - 124	166 - 187
	Mid Point ($)		20	36	46	75	118	177

Table 4-2 Price Estimates for Sensitivity Cases for B.C. Compliance Instruments (CDN $2008)

Year		2012	2015	2020
WECC Compliance Instruments applied to price cap scenario	Range ($)	9 - 14	16 - 46	29 - 126
	Mid point ($)	12	31	78
BC Compliance Instruments Only applied to all scenarios	Range($)	78 - 116	140 - 258	258 - >323
	Mid point ($)	97	199	>291

4.2.3.1 Economic modeling activity subsequent to the Natsource report

These price forecasts are based on existing economic modeling available at the time the Natsource GHG price forecast report was written in December 2007.

Price estimates for S. 2191, the most stringent of the U.S. Bills examined by Natsource, were not available in December 2007, although subsequently several organizations have conducted modeling of the Bill. As identified earlier, a high degree of uncertainty exists surrounding the level of targets that ultimately will be adopted in U.S. legislation. The U.S. Senate has not yet debated S. 2191. The debate is likely to address targets and economic costs and will provide some further indication of emerging views on what level of target is considered both necessary and economically acceptable. These views will continue to evolve in 2008, and following the election of a new President and Congress in November. In view of the still preliminary state of discussion on climate proposals in the Congress, it is not clear that the targets in S. 2191 are more representative of the targets that will ultimately be adopted than those in S. 280. If the targets in S. 2191 are more representative, then prices under a U.S. program likely would be in the upper ranges of the Linked Market and the Made in North America Aggressive scenarios, or indeed higher than those scenarios. Given the uncertainty over which U.S. GHG Bill will be enacted, Natsource has not recommended changes to its GHG price forecast report.

Price estimates for the least stringent of the proposals examined by the Natsource GHG price forecast report (S. 1766) were not available at the time the report was prepared. These estimates relate only to prices in the U.S. under S. 1766, and do not directly impact the report's estimates for the Price Cap scenario. The Price Cap scenario price estimates in the report are prices for regulated entities in Canada, and the Price Cap scenario assumes that the U.S. and Canada do not link their trading programs.

In Canada, the Federal Government released its economic analysis and modeling of Canada's federal plan on March 10, 2008.[60] The modeling results of this analysis, which were not available at the time the scenarios in the Natsource GHG price forecast report were developed, suggest that Canada's current policy approach, including an intensity

[60] Environment Canada, "Turning the Corner: Detailed Emissions and Economic Modeling", March 2008. Available at http://www.ec.gc.ca/doc/virage-corner/2008-03/571/tdm_toc_eng.htm.

target with a Technology Fund compliance option, would lead to prices in Canada that are higher than those considered in the Price Cap scenario (which assumes Canada's current approach extends indefinitely), and to higher prices in Canada in the Linked Markets scenario (which assumes Canada's current approach extends to 2015). The analysis estimates the price of GHG emission permits under the March 2008 Regulatory Framework will be approximately $25/tonne in 2010-2012, rising to $65/tonne in 2018-2020. The Technology Fund contributions ($15/tonne in 2010-2012, $20 in 2013 and escalating at the rate of nominal Gross Domestic Product thereafter) moderate prices at the beginning of the program but play a limited role after 2014 given the limited access to the Technology Fund. In 2018-2020 contributions are exhausted and prices increase to $65. These prices are somewhat higher than in the Linked Markets scenario through 2015 and significantly higher thereafter. This underscores the uncertainty in forecasting GHG prices, and suggests that prices may be trending toward higher levels, although the absence of competing analyses, and the absence of detailed assumptions in the Federal Government's economic analysis, raise questions as to whether the Federal Government's relatively high price estimates are representative.[61]

4.2.4 Use of GHG Price Forecast in 2008 LTAP Analysis

4.2.4.1 Direct Impact in the Portfolio Analysis

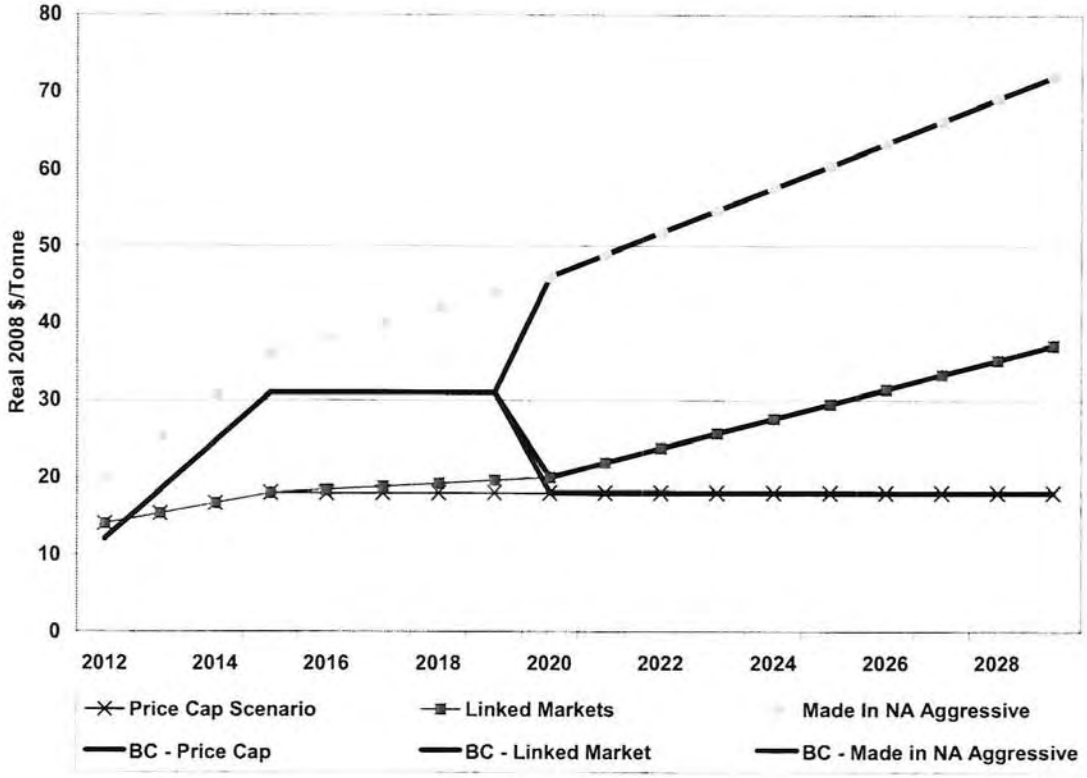
Both the B.C. carbon tax and the Natsource GHG price forecast have been included in the 2008 LTAP Chapter 5 portfolio analysis. The B.C. carbon tax is included as part of the fuel cost of any natural gas-fired generation located in B.C. The tax is assumed to be that identified in the *Carbon Tax Act*, with the ultimate tax level in 2012 being extended through the remainder of the planning horizon.

BC Hydro incorporated Natsource's GHG price forecast into its portfolio analysis based on the Mid Point values presented in Table 4-1 and Table 4-2 as trended in Figure 4-1. The

[61] Environment Canada stated the following with respect to the modelling: "Analysis of the economic impact of the Regulatory Framework is complex. The results presented here are based on an economic modeling structure that has a longstanding track record in Canada and the United States with respect to impact analysis of climate change measures. This gives us high confidence in our conclusions, but it must be recognized that no single economic model can claim absolute certainty in its results. As with complex policy analysis, application of alternate modelling approaches to generate a range of estimates is desirable. To this end, Environment Canada is working with other government departments and external experts to support Canada's environmental agenda on the basis of a robust and comprehensive analytical capacity." *Supra*, note 16.

Figure presents both the broader planning scenarios as well as the scenarios that would relate to B.C. until the GHG offset markets link. The methodology of how the GHG price forecast is incorporated is described in Chapter 5.

Figure 4-1 GHG Offset Cost Scenarios in Portfolio Analysis



4.2.4.2 Accounting for Indirect Impacts of GHG Regulations

In addition to the direct impacts identified above, there is an indirect impact of GHG regulations for utilities' resource planning environment through the scenario forecasts of natural gas and electricity market prices. This impact is described in the following sections on natural gas and electricity markets that follow.

4.3 Natural Gas Price Forecast

4.3.1 Global Energy Forecasts

For the 2008 LTAP, BC Hydro retained Global Energy for fundamental research and natural gas price forecasts. This is an extension of the types of services that Global Energy has provided in the past; Global Energy has provided BC Hydro with market forecast services for several years and BC Hydro has used a Global Energy electricity market simulation model to develop its recent electricity price forecasts.[62]

The natural gas price scenarios developed for BC Hydro by Global Energy are derived from three internally consistent, fundamentals-based scenarios of future market conditions that Global Energy developed for the CEC as part of the CEC's IEPR process. The three natural gas price forecasts – referred to as 1B (Base), 2 (High) and 5BPlus (Low) – were selected because they cover a wide range of possible natural gas prices.

At a macro level, the natural gas prices identified in each of the scenarios are impacted by the underlying assumptions of North American natural gas supply and demand. Within the Western Canadian and U.S. region, the natural gas demand is impacted by the forecast of electricity demand and the relative competitiveness of natural gas-fired generation. The Global Energy natural gas forecast takes into account the impact of electricity demand in the region, various scenarios of penetration of DSM and renewable generation in the region.

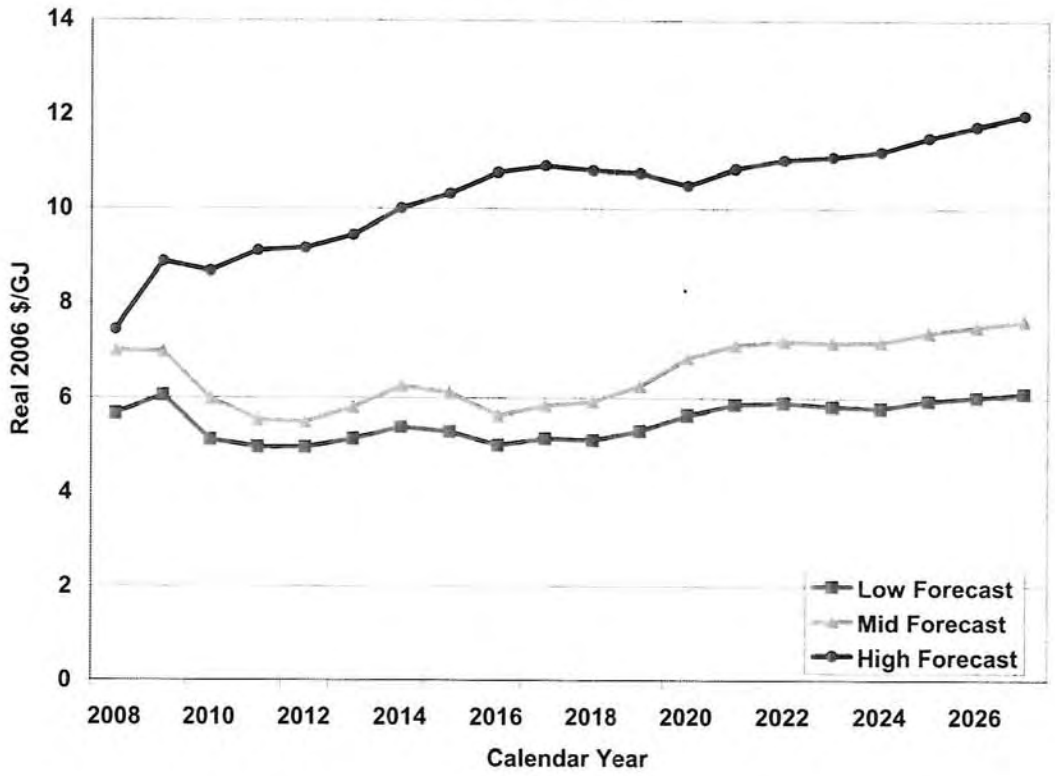
BC Hydro requested that Global Energy provide its expert view as to the relative probabilities of the three scenarios. Following a structured review, Global Energy assigned probabilities to its three natural gas forecasts as follows: 1B (Base) – 44 per cent; 2 (High) – 53 per cent; and 5BPlus (Low) – 3 per cent.

The details regarding the underlying conditions (global and within the western region) that resulted in the three gas price scenarios, the analysis and review that went into creating the scenarios, and the analysis that went into assessing the relative probabilities of the three scenarios are provided in the Global Energy report contained in Appendix I.

[62] BC Hydro is a licensee of the Global Energy Decisions MARKETSYM simulation software. BC Hydro has used the software to produce forecasts for more than ten years.

Figure 4-2 presents the three scenarios of natural gas prices for the Sumas Hub[63] in Canadian dollars.

Figure 4-2 Natural Gas Price Scenarios at Sumas Hub by Calendar Year



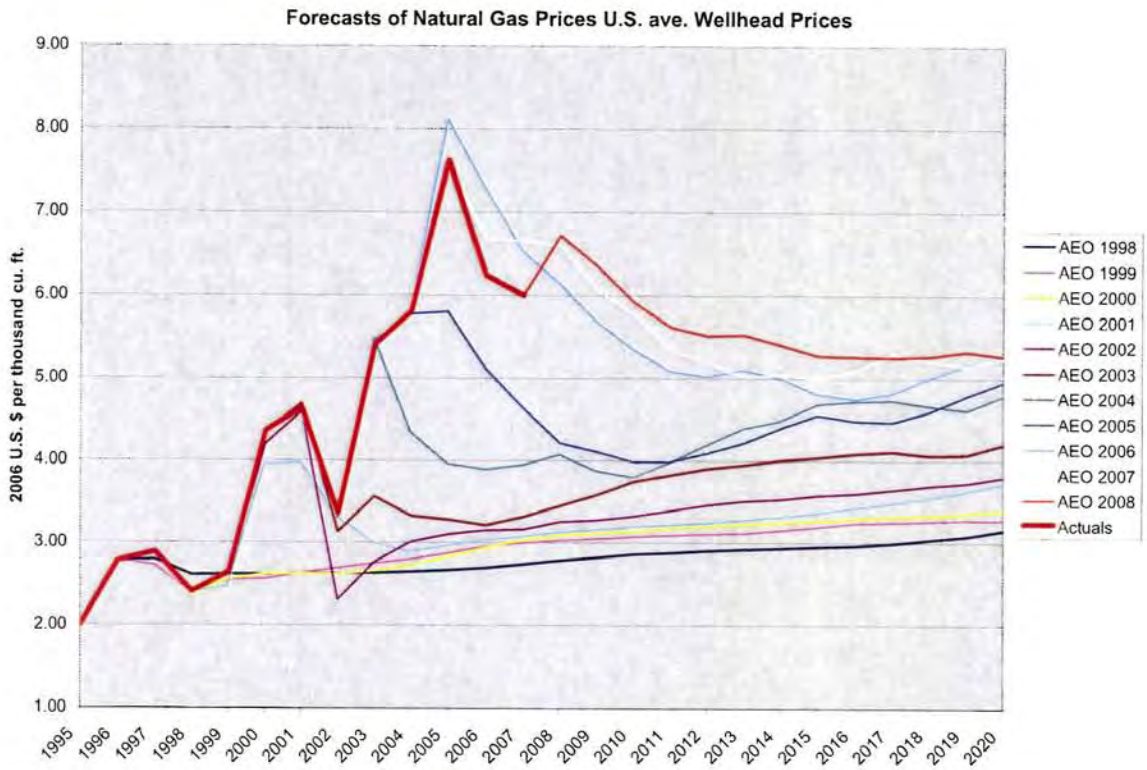
4.3.2 EIA Annual Energy Outlook Natural Gas Forecast

For the 2006 IEP/LTAP, BC Hydro used the EIA's 2005 Reference Case for its medium scenario. The 2008 LTAP does not rely on the EIA's Reference Case. Over the last 10 years, EIA's Annual Energy Outlook (**AEO**) forecasts have been consistently low. This is shown in Figure 4-3, which compares past EIA AEO forecasts to realized spot market prices. EIA AEO forecasts have increased over time but for the last 10 years have underestimated actuals. New York Mercantile Exchange (**NYMEX**) futures are much higher

[63] Sumas Hub is a natural gas trading hub located near the Canada/U.S. border.

than the EIA AEO forecasts. For example, current market forwards at Henry Hub[64] are over $11/Million British Thermal Units (**MMBtu**) ($USD) for each of the next 12 months.[65]

Figure 4-3 Comparison of EIA Natural Gas Forecast



4.3.3 Use of Natural Gas Price Forecast in 2008 LTAP Analysis

The three Global Energy natural gas price forecasts were used as key inputs to develop three electricity price forecasts, described below. In addition, the use of these three scenarios in the 2008 LTAP portfolio analysis is described in Chapter 5. The three natural gas price forecasts, and the three GHG price forecasts, combine two of the risk factors that concern BC Hydro most: fuel price and GHG risk. Both factors primarily affect natural gas-fired generation facilities. Use of the scenarios in the Fort Nelson Resource Plan analysis is described in Appendix N1.

[64] Henry Hub is the pricing point for natural gas contracts traded on the New York Mercantile Exchange (Nymex).

[65] Natural Gas Forwards from Nymex's April 29th 2008 trading session www.nymex.com.

4.4 Electricity Price Forecast

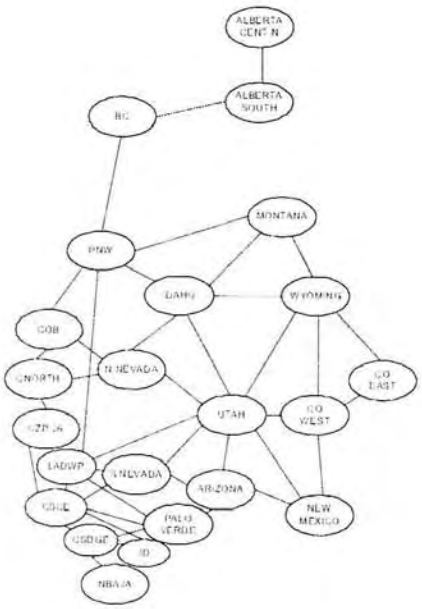
4.4.1 General

WECC's electricity and natural gas markets have become closely inter-related since natural gas has become the predominant fuel for new electricity generation. The inter-related nature of the electricity and natural gas markets means that market prices for electricity are closely tied to the market prices for natural gas. This is due to natural gas-fired generation's operational flexibility and relatively high variable operating costs, which typically place it last in the order of generation resources to be dispatched. As such, natural gas-fired generation is the marginal market resource and high gas prices are likely to drive high electricity market prices.

Electricity prices are modelled under a computer simulation of the hourly supply-demand balance for the WECC regional market, which include the Western U.S. states, B.C. and Alberta. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the market price for that hour. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. The electricity and gas prices are calculated for the next 20 years.

The electricity price forecasts were developed in a two-stage process. In the first stage, Global Energy developed the database of scenarios of loads and resources in the western region. This forecast expressly includes the underlying assumptions for DSM, renewable resources and conventional resources in the region by sub region (refer to Figure 4-4) and by scenario.

Figure 4-4 WECC Transmission Area Configuration



The second stage was completed by BC Hydro and starts from the Global Energy database and the three natural gas scenarios. BC Hydro made certain modifications to the database with respect to the B.C. area, including additional precision with respect to the BC Hydro resources.[66]

4.4.2 Incorporation of GHG Price Forecast

In the second stage of developing the 2008 Electricity Price Forecast, BC Hydro simulated the impact of GHG offset costs on the region. As part of this exercise, Natsource was asked to derive thermal generator "performance standards". The importance of the thermal generator performance standards is that GHG costs are only incurred for GHG emissions above the particular performance standard. Natsource reviewed the GHG legislation and policy developments in the Canadian provinces and U.S. states that make up the WECC. Natsource then converted the various legislative requirements into GHG intensity targets. Natsource and BC Hydro found the following:

[66] It is a standard practice to modify the base Global Energy database with specific information BC Hydro has with respect to the current and forecast local conditions.

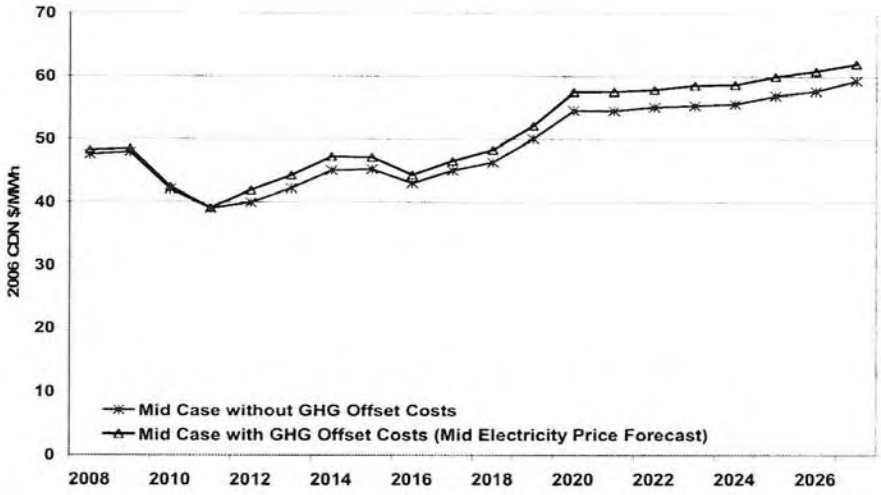
- B.C. requires all new thermal generators to have zero net GHG emissions (the *Emissions Standards Act* and Policy Action No. 18 of the 2007 Energy Plan). This results in the B.C. performance standard being set at zero;

- California, Washington State and Oregon require thermal plants to offset to the equivalent of a CCGT. This results in the California, Washington State and Oregon performance standards being set at 360 tonnes of CO_2e/GWh. The 360 tonnes of CO_2e/GWh is the GHG intensity of a new, efficient CCGT. This means that generally speaking new CCGTs are exempt from GHG offset costs in all three states. Coal-fired generators and lower efficiency gas-fired generators would have to offset to the level of a CCGT. Washington State mandated a review of its performance standard every 5 years. California and Oregon have to date been silent on whether and when their respective performance standards will be updated; however, California's performance standard is an interim measure until the WCI GHG cap-and-trade system is in place; and

- In the rest of WECC (Alberta, Arizona, New Mexico, Montana, Utah, Colorado, Nevada, Idaho, Wyoming), some of these jurisdictions do not yet have legislation addressing GHG emission targets, while others have only broad state-wide targets. This results in the rest of WECC performance standard being set at 600 tonnes of CO_2e/GWh. The 600 tonnes of CO_2e/GWh is the mid point of the range of 500-700 tonnes of CO_2e/GWh developed by Natsource based on the GHG emission intensity of higher emissions gas-fired generators or fairly clean coal-fired generators. Generally coal-fired generators have GHG emissions intensities of between 495 to over 1,000 tonnes of CO_2e/GWh.

Including the GHG offset cost assumptions into the 2008 Electricity Price Forecast resulted in an increase of between $2.00/MWh and $4.00/MWh (2006 dollars) in the electricity prices across the region. Figure 4-5 presents the impact of the GHG offset cost assumption as measured at Mid C based on Natsource's linked market GHG scenario.

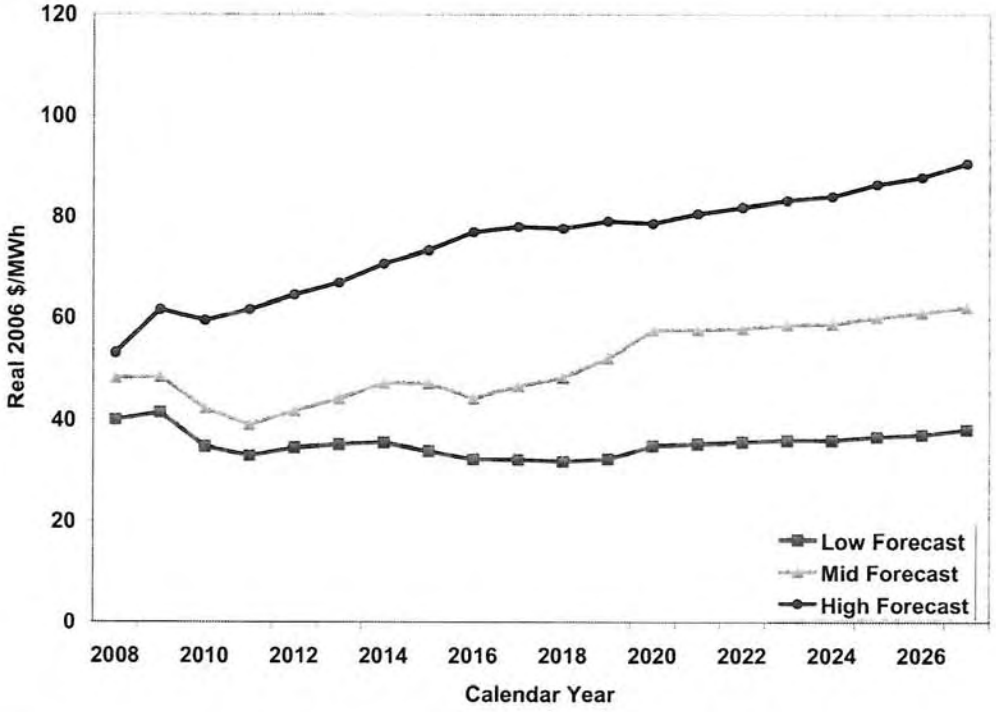
Figure 4-5 Effect of GHG Offset Cost Assumptions on the Mid-C Electricity Price



4.4.3 2008 Electricity Price Forecast

The forecast for Mid-C in Canadian dollars is provided in Figure 4-6.

Figure 4-6 Electricity Price Scenarios at Mid-C by Calendar Year



4.4.4 Use of Electricity Price Forecast in 2008 LTAP Analysis

The use of these three scenarios in the 2008 LTAP portfolio analysis is described in Chapter 5. Use of the scenarios in the Fort Nelson resource plan analysis is described in Appendix N1. The 2008 Electricity Price Forecast is used to determine compensation for non-firm energy produced by successful bidders in the Clean Power Call. The 2008 Electricity Price Forecast will also be used to determine the relative values of monthly on-peak and off-peak energy produced by successfully bidders in the Clean Power Call. Refer to section 6.2.6 for details.

4.5 Market Assessment for Clean or Renewable Electricity

One of the more significant changes in U.S. markets since the 2006 IEP/LTAP is the increasing number of U.S. states that have passed RPS legislation. As of May 1, 2008, 25 U.S. states and the District of Columbia, including eight WECC states, have adopted mandatory RPS requirements. A mandatory RPS obligates utilities to include in their resource portfolios a certain amount of electricity from renewable energy resources, such as wind and small hydro (generally less than 30 MW and with no storage).

RPS requirements vary considerably with respect to resource eligibility, whether they allow unbundled RECs,[67] and arrangements for enforcement and penalties. The use of unbundled RECs separates the attributes of renewable electricity – such as emissions from a generator - from the electricity itself, creating an entirely separate market for the renewable attribute alone, which is unencumbered by the physical constraints of the transmission grid.

4.5.1 Global Energy Analysis

BC Hydro retained Global Energy to:

- Obtain an indication of the possibility of B.C.-based supply being able to access the WECC market; and

[67] Initially, all RECs are "bundled" together with their associated electricity that is produced at the renewable electricity generation facility. RECs can be conveyed with the electricity unless they are "unbundled" from the electricity and recorded in a certificate that may be traded separately from the electricity itself: see section 2.1 of Global Energy's report entitled "Renewable Energy Credit – Markey Analysis of Potential Renewable Energy Sale in WECC", attached as Appendix H.

- Obtain an objective view as to what the value of RECs would be in the future.

Global Energy concludes that most WECC state RPS legislation allows out-of-country renewable electricity products, with some states being more restrictive than others. Refer to Table 4-3, which summarizes Global Energy's findings. Refer to Appendix H for further details.

Table 4-3 RPS Eligibility for Wind and Hydroelectric resources

State	Wind	Hydro	Unbundled RECs allowed?	Geographic restrictions
Arizona	Yes	Hydroelectricity from facilities that became operational after January 1, 1997, as well as hydro used to firm intermittent renewables, and incremental generation from upgrades from facilities that became operational before January 1, 1997 is eligible.	Arizona allows the use of unbundled, tradable RECs.	No restrictions.
California	Yes	Facilities with capacity below 30 MW are eligible. Facilities outside of California must not require new water permits or licenses from any government bodies.	California Public Owned Utilities can use unbundled RECs if they so choose. California Investor Owned Utilities require California Public Utilities Commission (CPUC) approval before doing so. The CPUC is likely to approve the use unbundled RECs soon.	RECs must be from facilities connected to WECC that became operational on or after January 1, 2005, or from incremental generation from a project expansion after January 1, 2005. Facilities outside the US must operate in a manner that is protective of the environment, similar to facilities located in California.
Colorado	Yes	Yes	Colorado House Bill 07-1281 allows tradable RECs (which are the equivalent of unbundled RECs).	No restrictions.

State	Wind	Hydro	Unbundled RECs allowed?	Geographic restrictions
Montana	Yes	Hydroelectricity from facilities with a capacity of 10 MW or less are eligible.	Yes	RECs from facilities in other states that became operational after January 1, 2005, are eligible.
Nevada	Yes	Certain hydropower is eligible.	Nevada's Assembly Bill No. 3 refers to acquiring "Portfolio Energy Credits" to satisfy the Nevada RPS. These Portfolio Energy Credits are essentially the same as RECs. These can be unbundled.	No restrictions.
New Mexico	Yes	Hydroelectricity from facilities that became operational after July 1, 2007 are eligible.	Yes	RECs must be from facilities connected to WECC.
Oregon	Yes	Hydroelectricity from facilities that became operational on or after 1995 are eligible.	Yes	Unbundled RECs must be from with in the WECC territory, or from an area deemed "environmentally preferable" by the Bonneville Power Administration. Bundled RECs must be from the U.S. portion of the WECC territory.
Washington	Yes	Only incremental hydroelectricity from efficiency improvements completed after March 31, 1999, at facilities located in the U.S. Pacific Northwest is eligible.	Washington state's *Energy Independence Act* allows tradable (unbundled) RECs.	Electricity must be from facilities in the U.S. Pacific Northwest that became operational after March 31, 1999.

Global Energy further confirms that U.S. state RPS requirements are likely to continue if the WCI or some other GHG cap-and-trade system is brought into effect. Global Energy's analysis confirms BC Hydro's view that title to "Environmental Attributes" resulting from the Clean Power Call must be transferred to BC Hydro so that the value from any sales of Environmental Attributes flows back to BC Hydro's customers. Refer to section 6.2.6.

Table 4-4 shows Global Energy's expected range of REC prices.

Table 4-4 Expected REC (U.S. $/MWh)

Year	2010	2015	2020
High	57	59	62
Low	11	14	18

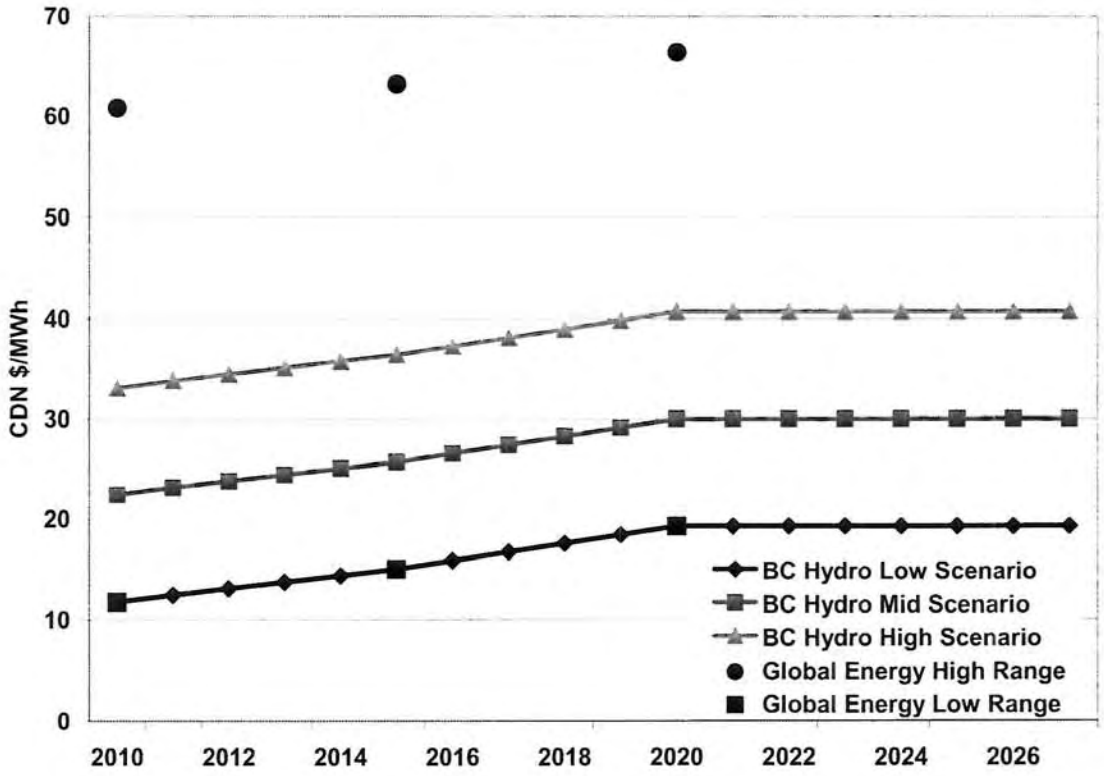
Refer to the Global Energy report entitled Renewable Energy Credit – Market Analysis of Potential Renewable Energy Sale in WECC", attached as Appendix H, for further details.

4.5.2 Use of Global Energy Analysis in 2008 LTAP Analysis

As was the case in the 2006 IEP/LTAP, sales and purchases of electricity are modelled in the 2008 LTAP portfolio analysis. The sales and purchases assumed to be made in the analysis are based on pricing at two external trading hubs – the Mid-C and the Alberta AESO Hubs. In each case, wheeling and losses are captured to the respective hub. The value of these sales and purchases are for the base electricity product (the electrons), without any representation of the incremental value that may be derived from the sale or purchase of RECs or any other form of clean or renewable attribute.

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 are allowed to reduce their RPS obligations because of rate impacts.

Figure 4-7 BC Hydro's Market Price Scenarios for RECs as compared to the Global Energy Forecast REC Price Range



4.5.3 Transmission

As part of its long portfolio analysis in Chapter 5, BC Hydro undertook an analysis of transmission access.

Current Interconnection Ratings

B.C. is interconnected with both the Alberta and the U.S. markets. The interconnection going into Alberta is typically limited to between 400-600 MW, although the rating can be increased on a short-term basis by actions within Alberta. The interconnection going into the U.S. has a concurrent limit of 3150 MW across the two points of interconnection. However, the actual available North-to-South scheduling capability of the U.S. intertie during Heavy Load Hours (**HLH**) is often substantially less (1500-2500 MW range) than the 3150 MW rating.

As set out in the long portfolio analysis found in Chapter 5, under SD 10 planning criteria, BC Hydro would under normal water conditions typically have 6000-8000 GWh/yr of energy that would be surplus to its load requirements. This surplus could exceed, but with a decreasing probability of occurrence, 10,000 GWh in a year. Even at this level of energy surplus the existing transmission system is, with appropriate planning, physically capable of moving 10,000 GWh out of B.C. in addition to meeting load. To move this surplus energy however, could have a significant economic opportunity cost because transmission and generation limits would require the surplus energy to be sold into time periods that typically have less economic value (e.g., Light Load Hours (**LLH**) and spring/late fall HLH) than other times of the year.

Under this circumstance, consideration could be given to expanding the capability of the interconnection. The direct benefit that could be obtained from increasing the transmission limits would depend upon the relationship between:

- the cost of that transmission upgrade;
- the limits on generation and storage capability; and
- the incremental market value that could be obtained by selling the energy into higher value time periods.

There could also be indirect benefits associated with increased transmission capability that would have to be quantified. A key consideration is that under the current BCTC tariff, BC Hydro will backstop the cost of expansion via its NITS but to guarantee that it will receive the associated benefits BC Hydro would also need to secure the capacity rights via long term firm Point-to-Point contracts.

Western Renewable Energy Zone

A number of U.S. states, including Arizona, California, Colorado, Nevada, New Mexico, Utah and Wyoming are working to identify renewable resources in their states and to determine the transmission needed to move generation to load centers. However, concerns over restricting renewable procurement and transmission development to in-state and the resulting higher costs to consumers has led the U.S. Western Governors' Association and other stakeholders to support the Western Renewable Energy Zone (**WREZ**) initiative to

develop a consensus proposal among the WECC jurisdictions on how best to develop and deliver energy from renewable resource areas throughout the WECC region, including B.C., to load centers. Specifically, the WREZ initiative is to:

- Identify all commercial renewable resource potential in the WECC, aggregate the best potential into Renewable Energy Zones (**REZ**), and identify transmission costs to deliver resources from each REZ to specified load centers; and
- Develop conceptual transmission plans to deliver energy from the highest ranking REZs to identified load centers.

BC Hydro will continue to monitor the WREZ.

ATTACHMENT 2

1	2009	ANALYSIS OF FORECAST POWER PURCHASE EXPENSE											
2		FOR THE YEAR ENDING DECEMBER 31, 2009											15-Dec
3		2	3	4	5	6	7	8	9	10	11	12	13	
4		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
5	**ENERGY GW.h**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
6	FortisBC	156	151	140	119	128	128	136	118	123	111	118	152	1580.649
7	Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857.415
8	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	65.093
9	Brilliant Regulated	0	0	0	0	0	0	0	0	0	0	0	0	0.000
10	Cominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000
11	Small Misc IPP Resource	1	0	1	1	3	2	3	1	1	1	1	1	13.000
12														
13	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
14		0	0	0	0	0	0	0	0	0	0	0	0	0.000
15	CPC Loss, Wheeling & PPA Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0.000
16	DSM	2	2	2	2	2	2	2	2	2	2	2	2	25.192
17	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0.000
18	Market Capacity - ENERGY	1	0	4	0	0	0	3	0	0	0	0	0	7.823
19	Market Energy Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0.000
20	BCH Purchase	126	108	107	56	30	30	42	32	56	86	115	119	907.879
21		----	----	----	----	----	----	----	----	----	----	----	----	----
22	Gross Load	368	324	311	270	256	242	253	251	249	263	299	340	3426.113
23	Surplus	0	0	0	0	0	4	27	0	0	0	0	0	30.938
24	**RATE (Mills/kW.h)**												Pwr Pur =	1851.210
25	Surplus Rate	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
26	Brilliant Base Plant	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
27	Brilliant Upgrade	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	
28	Brilliant Regulated	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	
29														
30	Market Capacity - ENERGY	80.32	74.49	61.69	56.30	45.65	47.77	94.80	115.57	84.12	73.68	84.44	100.38	
31	Market Energy Purchase	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
32	BCH : Purchase	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	
33	IPP Rate	28.254	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	
34	**ENERGY EXPENSE ($000)**													
35	Surplus Revenue	$0	$0	$0	$0	$0	($76)	($893)	$0	$0	$0	$0	$0	-968.967
36	Brilliant Base Plant	$2,789	$2,146	$2,007	$2,785	$2,699	$2,459	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	29244.667
37	Brilliant Upgrade	$18	($17)	($11)	$254	$360	$335	$360	$330	$25	$16	$8	$9	1685.909
38	Brilliant Regulated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
39		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
40														
41	IPP Costs	$14	$11	$20	$17	$71	$62	$76	$17	$20	$14	$23	$23	367.302
42	BCH Purchase	$3,547	$3,056	$3,029	$1,588	$859	$836	$1,196	$907	$1,594	$2,437	$3,247	$3,355	25651.216
43	Market Capacity - ENERGY	$55	$0	$251	$0	$0	$0	$283	$1	$0	$0	$6	$0	596.283
44	Market Energy Purchase	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
45		----	----	----	----	----	----	----	----	----	----	----	----	----
46		$6,424	$5,197	$5,295	$4,644	$3,989	$3,616	$3,723	$4,186	$3,889	$4,587	$5,427	$5,601	56576.410
47														
48	**CAPACITY (MW)**													
49	FortisBC	202	199	181	183	187	178	188	203	200	194	193	208	2316.639

50	Brilliant Base Plant	123	123	87	117	106	100	106	115	119	119	123	123	1359.238	
51	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238.000	
52	Brilliant Tailrace Capacity	4	3	1	3	6	6	6	4	1	1	3	5	42.200	
53	Cominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000	
54	Market Capacity	7	0	67	0	0	0	48	5	0	0	4	0	131.047	
55		0	0	0	0	0	0	0	0	0	0	0	0	0.000	
56	FortisBC DSM	5	4	4	4	4	3	3	3	4	4	4	5	45.400	
57		0	0	0	0	0	0	0	0	0	0	0	0	0.000	
58	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000	
59	Cominco Market Capacity	150	75	0	0	0	0	0	0	0	0	75	125	425.000	
60	CPC Market Capacity	0	0	0	0	0	0	0	0	0	0	0	25	25.000	
61	BCH : Billing Capacity	190	176	190	165	143	188	190	190	143	182	190	168	2113.794	
62	BCH : Used for Load	190	176	190	165	134	188	190	190	111	182	190	168	2073.548	
63	BCH : Excess Purch	0	0	0	0	0	0	0	0	0	0	0	0	0.000	
64		----	----	----	----	----	----	----	----	----	----	----	----	----	
65	Gross FortisBC Monthly Peak	701	600	551	492	455	495	560	539	454	519	613	666	6643.700	
66															
67	Capacity Planning Load	701	600	551	492	455	495	560	539	454	519	613	666	6643.700	
68	**RATE ($/MW-month) / EXPENSE ($000)**														
69	BCH 3808 Rate	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52		
70	BCH 3808 Capacity Charge	$916	$847	$916	$796	$687	$907	$916	$916	$687	$877	$916	$810	10189.586	
71	BRD Tailrace Capacity Charge	$16	$11	$4	$9	$22	$22	$21	$13	$3	$3	$12	$17	152.569	
72														0.000	
73	Cominco Capacity Charge	$1,001	$506	$0	$0	$0	$0	$0	$0	$0	$0	$423	$705	2635.513	
74	CPC Capacity Charge												$195	195.000	
75	Total Capacity EXPENSE($000)	$1,933	$1,363	$920	$805	$709	$929	$937	$929	$690	$880	$1,351	$1,728	13172.668	
76															
77	**TOTAL POWER PURCH EXPENSE($000)**														
78	Surplus Revenues	$0	$0	$0	$0	$0	($76)	($893)	$0	$0	$0	$0	$0	-968.967	
79	Export Wheeling Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000	
80	Brilliant	$2,823	$2,141	$1,999	$3,047	$3,081	$2,816	$3,081	$3,274	$2,279	$2,139	$2,164	$2,241	31083.146	
81															
82	BCH	$4,463	$3,902	$3,945	$2,384	$1,546	$1,743	$2,112	$1,823	$2,280	$3,314	$4,163	$4,165	35840.802	39.584
83	BCH Excess/Unallocated Costs	$0	$0	$1	$4	$11	$25	$43	$7	$5	$0	$0	$0	96.996	
84	Call Option	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000	
85	Market Spot Purchase & Com Capacity	$1,056	$506	$251	$0	$0	$0	$283	$1	$0	$0	$429	$900	3426.796	
86	IPP	$14	$11	$20	$17	$71	$62	$76	$17	$20	$14	$23	$23	367.302	
87															
88	Capital Projects	($43)		($65)								($75)	($26)	-208.431	
89	Special & Accounting Adjustments													0.000	
90	Balancing Pool Adjustments	$226	$769	$661	($520)	($226)	$57	($20)	($848)	($283)	($424)	($158)	$576	-189.217	
91		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	
92	**TOTAL**	$8,539	$7,328	$6,812	$4,932	$4,483	$4,627	$4,683	$4,274	$4,301	$5,043	$6,545	$7,880	$69,448.427	

ATTACHMENT 3

AGREEMENT FOR THE SUPPLY OF ELECTRICITY

WHOLESALE SERVICE

FORTISBC INC.

and

THE CORPORATION OF THE CITY OF NELSON

dba

"Nelson Hydro"

FORTISBC INC.

THE CORPORATION OF THE CITY OF NELSON

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THIS AGREEMENT is made as of the 1st of November 2004.

BETWEEN:

FORTISBC INC.

(the "Company")

AND:

THE CORPORATION OF THE CITY OF NELSON

(the "Customer")

WHEREAS the Company is a supplier of electricity in the southern interior region of the Province of British Columbia;

AND WHEREAS the Customer wishes to purchase electricity from the Company for its own use and for resale to customers within the Customer's Service Area as hereinafter described;

AND WHEREAS both the Company and the Customer have agreed to the principles set forth in the Proposed Settlement Agreement resulting from the British Columbia Utilities Commission Decision dated March 10, 1999.

NOW THEREFORE this Agreement witnesses that in consideration of the terms and conditions hereinafter set forth the Parties covenant and agree as follows:

1. DEFINITIONS

In this Agreement:

(a) **"Check Metering"** means any measurement device or system installed, owned and maintained by the Customer to check the measurements and calculations carried out by the Metering System.

(b) **"Commission"** means the British Columbia Utilities Commission.

(c) **"Commodity Service"** means the supply of power, expressly excluding the services set forth in the Transmission Services Tariff, to the Customer by a third party and may include full or partial supply of the load requirements of the Customer.

(d) **"Demand Limit"** means the capability of the Company's facilities at each of the Points of Delivery, specified in Appendix A attached hereto.

(e) **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

(f) **"Maximum Demand"** means the highest months rate of taking of electricity by the Customer recorded in kilovolt-amperes by the Company from time to time.

(g) **"Metering System"** means the measurement device or system installed, owned and maintained by the Company used to determine the Customer's electricity consumption.

(h) **"Parties"** means both the Company and the Customer.

(i) **"Point of Delivery"** means the point or points at which the Customer's distribution system attaches to the Company's facilities, as specifically described in Appendix A attached hereto.

(j) **"Power Factor"** means the percentage determined by dividing the Customer's demand measured in kilowatts by the same demand measured in kilovolt-amperes.

(k) **"APSA"** means the Access Principles Settlement Agreement, also known as the Proposed Settlement Agreement, as amended from time to time, attached as Appendix A to the Commission Decision dated March 10, 1999 in the matter of the Access Principles Application and attached hereto as Appendix C.

(l) **"Service Area"** means the Customer's service area, the boundaries of which are shown by the red line on the map identified as the Customer's Electrical Service Boundaries, attached hereto as Appendix B and shall include any area(s) added from time to time by the municipality.

(m) **"Services"** means the supply and delivery of power to the Customer by the Company under the Agreement.

(n) **"Term"** means the period defined by subsection 2.01 herein.

(o) **"Transmission Services Tariff"** means the tariff as approved from time to time by the Commission for the use by a third party supplier to deliver power to the Customer or by the Customer to deliver power to a third party on the transmission and distribution facilities of the Company, including ancillary services required for the delivery of power.

2. TERM AND RENEWAL:

2.01 Term

The term of this Agreement shall be for a period of five years commencing on January 1, 2005. Upon expiration of that period this Agreement shall automatically be renewed for one additional five year period, unless the Customer, not less than one year nor more than 2 years before the expiration of the initial five year term, notifies the Company in writing of the termination of this Agreement, effective as of the end of the initial term.

2.02 Early Termination

If the Customer elects to engage any third party supplier to perform the Commodity Services and notice as provided for in the APSA is given to the Company the Customer may terminate this Agreement prior to expiry of the Term. If this Agreement terminates pursuant to this subsection, the Customer may then be liable to pay such costs, including stranded costs, if any, as directed by the Commission.

3. Access Principles Settlement Agreement

3.01 Access Principles Settlement Agreement Rights

Nothing contained in this Agreement shall be construed as affecting in any way the rights of either Party as set forth in the APSA (Appendix A to Commission Order No. G-27-99) nor as affecting in any way the rights of either Party to unilaterally make application to the Commission for further directions or orders from the Commission related to the terms and conditions of the APSA.

3.02 Regulatory Principles

If any provision of this Agreement is declared by the Commission to be inconsistent with the regulatory principles set forth in the APSA, the Parties shall amend that provision in such reasonable manner as achieves the intention of the declaration of the Commission. In the event the Parties cannot agree on such amendments, either Party shall be entitled to seek further direction from the Commission and the Parties hereby agree to be bound by such direction from the Commission.

4. CONDITIONS OF SUPPLY

4.01 Supply of Electricity

During the term of this Agreement, except in an emergency described in subsection 6.03, the Company shall supply up to the Demand Limit electricity required by the Customer solely for its own use and for supplying the needs of its customers within the Service Area. The Company shall supply electricity to the Points of Delivery through suitable plant and equipment in accordance with Good Utility Practice on a continuous basis, except as provided in this Agreement. The responsibility of the Company for the delivery of electricity to the Customer shall cease at the Points of Delivery.

4.02 Duty to Act Prudently in Arranging for Electricity Supply

Notwithstanding the provisions of subsection 4.03 and 4.04 the Company has a duty not to be imprudent in arranging for the supply of electricity required pursuant to subsection 4.01 of this Agreement and the Company will be liable to the Customer for any loss, injury, damage or expense caused to the Customer if the British Columbia Utilities Commission determines that the Company has failed to meet its duty not to be imprudent.

4.03 Failure to Deliver

At any time during a Company actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, the Company shall have the right to curtail or discontinue the supply of electricity to the Customer or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, the Company will not unduly discriminate in favour of or against the Customer in the supply of electricity.

4.04 Liability, Indemnity, Limitations and Requirements for Notice with Respect to Variations or Defects in Supply

The Company does not warrant a continuous supply of electricity or the maintenance of unvaried frequency or voltage and the Company, its servants or agents, shall not be liable to the Customer for any loss, injury, damage or expense of the Customer caused by or resulting from any suspension, discontinuance or defect in the supply of electricity, alleged or caused by an act or omission of the Company, its servants or agents, except for direct loss or damage to the physical property of the Customer, resulting from willful misconduct or negligent acts or omissions by the Company, its servants or agents.

It is also further agreed that the Company shall not be liable for loss or damage which could have been prevented, in whole or in part, if the Customer had taken reasonable protective measures.

It is also further agreed that the Company shall not be liable under this subsection unless the Customer has given notice to the Company of a potential claim within 30 days of when the Customer knew or ought to have known of the alleged loss or damage.

The liability of the Company under this clause applies only when the loss or damage arising from a single occurrence exceeds the sum of $10,000.00. In no event shall the liability of the Company exceed the sum of $10,000,000.00 for any single occurrence.

4.05 Mutual Indemnity

(a) The Company will indemnify and save harmless the Customer from and against any and all actions, proceedings, claims and demands that may be made against, and all loss or damage suffered by, the Customer by reason of any damage or injury to any person or property, including the property of the Customer, resulting from any electrical facilities owned by the Company located within the Service Area.

(b) The Customer will indemnify and save harmless the Company from and against any and all actions, proceedings, claims and demands that may be made against, and all loss or damage suffered by, the Company by reason of any damage or injury to any person or property, including the property of the Company, resulting from any electrical facilities owned by the Customer.

4.06 Commodity Services

The Customer shall have the rights set forth in the APSA to purchase power from a third party supplier and to meet part or all of its load requirements from Commodity Services.

4.07 Limits on Other Supply

Unless the Customer has exercised its rights pursuant to the APSA, the Customer shall, during the Term, only purchase electricity from the Company and the Customer's own customers for its own use and the use of its customers within the Service Area. The Customer may obtain up to 15 MWs of electricity from new generation owned and operated by the Customer or the Customer's customers.

4.08 Retail Access on the Customer's Facilities

The Customer shall give notice, consistent with the APSA requirements, in writing to the Company prior to providing the Customer's transmission and distribution services for the direct delivery of third party supply to a customer of the Customer.

4.09 Sales out of Service Area

If service to a customer outside or within the Service Area would require duplication of existing electrical plant which duplication could be avoided, then the Party that has the right to serve that customer pursuant to this Agreement may consent to the other Party serving that customer, such consent not to be unreasonably delayed or withheld.

5. CONDITIONS OF SERVICE

5.01 Supply Characteristics

The electricity to be supplied to the Customer shall be three-phase alternating current, having a nominal frequency of 60 hertz and the nominal voltages designated in Appendix A for the Points of Delivery, as amended from time to time.

The Company is a signatory of the Western Systems Coordination Council (WSCC) Reliability Management System (RMS) Agreement. The Company is committed to the service reliability standards detailed in this document and is liable for financial sanctions that WSCC can impose for non-adherence to those standards.

5.02 Underground Facilities

When the Customer requests the construction or installation of underground facilities, the Customer shall be responsible for the difference between the cost of constructing or installing the facilities underground and the cost of constructing or installing similar facilities above ground.

5.03 Ownership of Facilities

Notwithstanding the payment of any contribution by the Customer toward the cost of facilities pursuant to subsection 5.02, the Company shall retain full title to all facilities.

5.04 Revenue Guarantee

The Customer may be required to provide a revenue guarantee if the Company's facilities must be upgraded significantly to meet a proposed increase in the Customer's load in excess of 5000 kVA resulting from either a new customer or the increased load of an existing customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load. The revenue guarantee shall be in the form of cash, surety bond or other form of security satisfactory to the Company.

6. INTERCONNECTED OPERATION

6.01 Obligation of the Company

The maintenance by the Company of the agreed frequency and voltage at the Points of Delivery, set out in Appendix B, shall constitute delivery of electricity under this Agreement, whether or not any electricity is taken by the Customer, and shall, subject to subsection 10.01 constitute the complete discharge by the Company of its obligations to the Customer for Services.

6.02 Use of Facilities

Each Party shall cooperate with the other to secure the most efficient use of the plant and equipment of the other Party, which may include wheeling power through the other Party's transmission and distribution circuits to facilitate supply to either Party or its customers.

6.03 Exceeding Demand Limit

The Customer shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of the Company, unless an emergency condition requires that the Customer take in excess of the Demand Limit, and then only for the duration of the emergency condition. The Customer shall immediately advise the Company when such an emergency condition occurs. The Customer shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of the Company.

6.04 Restrict or Suspend Service

If the Customer fails to comply with the request of the Company pursuant to the previous paragraph, the Company may, when necessary in the opinion of the Company, restrict or suspend the supply of electricity to the Customer at the Point of Delivery summarily without further notice.

6.05 Avoidance of Excess Loads

The Customer shall provide for interconnection of its lines so as to transfer and arrange the loads taken at each Point of Delivery to balance as far as is practicable the loads at each Point of Delivery given the Demand Limit at each Point of Delivery.

6.06 Maintenance of Adequate Supply Capability

If at any time, except in an emergency condition described in subsection 6.03, the Customer notifies the Company that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, the Company shall take appropriate measures at no cost to the Customer to increase the supply capability at the Point(s) of Delivery to bring the Customer's anticipated future demand to or below 95 percent of the Demand Limit.

6.07 Customer's Facilities

The Customer shall be responsible for designing, constructing, installing and maintaining all auxiliary and interconnecting equipment on the Customer's side of the Point of Delivery and the Customer shall have ownership rights in all such auxiliary and interconnection equipment.

6.08 Installation of Facilities

All electrical facilities owned by the Customer from the Points of Delivery up to and including the Customer's overload and overcurrent protection and isolation devices shall be approved and coordinated in a manner satisfactory to the Company, and may be inspected by the Company from time to time. Notwithstanding the foregoing, the Company shall not require a higher standard for the Customer's electrical facilities than the standard of the Company facilities supplying that portion of the Customer's facilities.

6.09 Coordination of Protective Devices

Either Party shall notify the other Party in advance of any changes to its facilities that may affect the proper coordination of protective devices between the two systems.

6.10 Power Factor

The Customer shall endeavor to regulate its load so that the Power Factor at each Point of Delivery will be no less than 90 percent, lagging.

6.11 Load Fluctuations

The Customer shall maintain and operate its equipment, and shall endeavor to ensure that its customers' equipment is operated in a manner that will not cause sudden fluctuations to the Company's line voltage, or introduce any influence into the Company's system deemed by the Company to threaten to disturb or disrupt its system or the plant or property of any other customer of the Company or of any other person.

6.12 Hazard to Property and Public Safety

Each of the Parties shall operate and maintain electrical plant within the Service Area so as to avoid hazard to the property of the other Party or danger to persons. To avoid hazard to property and to ensure public safety, the Parties agree that:

(a) All electrical generating facilities intended to be operated within the Service Area and in parallel with the Company's electrical system shall be installed only after the Company has been provided with full particulars of the facilities and the Company has given its written approval that the proposed operation of the facilities is satisfactory to the Company, acting reasonably. Upon completion, the Company shall be permitted to inspect the installation.

(b) The Customer shall ensure that any parallel generating facility installed shall not backfeed into the Company's system or facilities unless the Customer receives express permission in writing from the Company, which will not be unreasonably withheld.

(c) The Customer shall ensure that all standby generation facilities within the Service Area to provide electrical service in the event of a disruption of service shall be installed so that they remain at all times electrically isolated from the Company's electrical system either directly or indirectly, and shall be installed in such a way

that it is not possible for the facilities to operate in parallel with the Company's electrical system.

6.13 Permit to Install & Access

If any equipment or facilities associated with any Point of Delivery and belonging to a Party to this Agreement are or are to be located on the property of the other Party, a permit to install, test, maintain, inspect, replace, repair and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of the Term, together with the right of entry to said property at all reasonable times is hereby granted by the other Party.

The rights herby granted shall be exercised subject to prior notification and to any reasonable requirement of the granting Party necessary for the safety or security of Party's facilities and employees and the continuity of the Party's operations.

6.14 Use of City Streets and Lanes

During the existence of this Agreement the Company shall have the right and easement to enter upon and use the streets and lanes within the boundaries of the Customer for all purposes connected with the furnishing of electricity to the Customer, and, without limiting generality, for the purpose of erecting, maintaining, repairing, replacing, removing or using poles, wires, meters, machinery and equipment, subject to the plan of any new erection of pole lines receiving such reasonable approvals as the Customer deems necessary.

6.15 Drawings to be Provided

If either Party is required or permitted to install, test, maintain, inspect, replace, repair, remove or operate equipment on the property of the other, the owner of such property shall furnish the other Party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other Party of any subsequent modification which may affect the duties of the other Party in regard to such equipment, and furnish the other Party with accurate revised drawings, if possible.

6.16 Inspection of Facilities

Each Party may, for any reasonable purpose under this Agreement, inspect the other Party's electrical installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such Party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting Party shall observe written instruction and rules posted in facilities and such other necessary instructions or standards for inspection as the Parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

7. PLANNING AND OPERATING INFORMATION

7.01 Increases in Maximum Demand

The Customer shall notify the Company in writing of any anticipated additional single load in excess of 5000 kVA resulting from a new customer or the increased load of an existing customer, providing as much advance notice of the increase as can be given in the circumstances. The Company shall endeavor to provide the service requested by the date the increase is intended to become effective, or as soon thereafter as is practicable.

7.02 Records and Forecasts

Each Party shall retain and make available upon request for the other Party log sheets, records of recording meters, and any other readily available information of an operational character relating to the electricity supplied under this Agreement, excluding non-public records of a financial or business nature relating to the Customer's utility undertaking.

7.03 General Information Requests

The Parties agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the Parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

7.04 Load-Resource Forecast

By June 30 of each year, the Parties agree to exchange a five year forecast of loads and resources for their respective electrical systems including a forecast of their Maximum Demand at each Point of Delivery normalized for average weather conditions and shall also provide a forecast of energy consumption for each year. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

7.05 Load from Previous Year

Before the end of February in each year, the Customer shall provide the Company with a record of the number of customers and load by customer class for the previous calendar year.

7.06 Scheduled and Maintenance Outages

Each party shall submit to the other Party a list of outages scheduled for inspection, testing, preventative maintenance, corrective maintenance, repairs, replacement or improvements that might affect the delivery of electricity under this Agreement, providing as much advance notice of the outage as can be given in the circumstances. The Parties shall use reasonable efforts to keep such schedules current and to revise such schedules so as to minimize the impact on the other Party's system.

8. METERING

8.01 Installation

The Company shall furnish, install and maintain the Metering System except the 63 kV metering units at Bonnington and Rosemont which are owned by the Customer. The Customer shall provide metering quantities to the Company. The Customer, in accordance with subsection 8.03, may furnish, install and maintain the Check Metering, each at their own expense, at the Points of Delivery, which shall accurately measure and record electricity within the limits prescribed by the federal Department of Consumer and Corporate Affairs ("Prescribed Limits") and pursuant to subsection 8.07.

8.02 Totalizing Metering

The Company shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

8.03 Check Metering

Check Metering and connecting equipment and facilities to be furnished by the Customer shall be satisfactory to the Company, and shall be installed in accordance with Good Utility Practice and in a manner satisfactory to the Company, acting reasonably.

8.04 Meter Tests and Adjustments

Unless otherwise agreed to by the Parties, each Party shall, at its own expense, arrange to have its meters tested by an inspector or accredited meter verifier authorized pursuant to the federal Electricity and Gas Inspection Act and regulations, as amended from time to time.

8.05 Inspection of Metering Equipment

Notwithstanding subsection 8.04, either Party may, after giving two days' notice, inspect in the presence of the other Party, the metering equipment installed in accordance with this subsection by the other Party, and may request that that metering equipment be tested by an inspector or authorized meter verifier.

(a) If the result of any test performed pursuant to this subsection shows that any of the metering equipment is not recording within the Prescribed Limits, then the owner of that metering equipment shall pay for the costs of testing.

(b) If after testing the metering equipment is found to be recording within the Prescribed Limits, the Party that made the request shall pay for the costs of testing.

8.06 Calculating the Amount to be Paid

The measurements recorded by the Metering System shall be used for calculating the amount to be paid for the electricity delivered to the Customer, except in the following circumstances:

(a) if a totalizing meter is temporarily not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the Customer's totalizing meter shall be used to determine the total consumption and demand, or, in the absence of a Customer totalizing meter, the Company's meters shall be used to determine the total consumption and demand taking into account

established load diversity until the Company's totalizing meter has been recalibrated;

(b) if the Metering System is not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the Customer's totalizing meter or , in the absence of a totalizing meter, the Customers' meters shall be used for calculating the amount to be paid for electricity delivered to the Customer;

(c) if neither the Metering System nor the Check Metering are in service or are found after testing to be not recording within the Prescribed Limits then the amount of electricity delivered since the previous billing shall be estimated from the best information available.

8.07 Prescribed Limits

If at any time the testing described in subsections 8.04 and 8.05 shows that the metering equipment was not recording within the Prescribed Limits, and if such recordings were used for billing purposes, then the billings shall be adjusted as prescribed by the Electricity and Gas Inspection Act.

8.08 Access to Meters

Each Party shall have the right, by giving suitable notice, to enter the property of the other Party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

9. INVOICES AND PAYMENT

9.01 Meter Reading

Meters shall be read at the end of each month. An accurate record of all meter readings shall be kept by the Company and shall be the basis for determination of all bills rendered for service.

9.02 Invoices and Payment

The Company shall render a billing invoice monthly pursuant to the terms of the Company's Electric Tariff, as amended from time to time.

9.03 Rates for Electricity

The Customer shall pay for Services during the term of this Agreement in accordance with the tariff applicable to the Customer filed with the Commission, as amended from time to time.

9.04 Demand Period and Demand

For billing purposes, Demand Period means the period, expressed in minutes, over which meter readings are integrated to obtain the Demand, which is the power measured in kilovolt amperes (kVA), or multiples thereof, at the Point of Delivery. In this Agreement and for billing purposes, the Demand Period shall be a a sixty minute clock hour interval.

9.05 Billing Adjustments

If the Company suspends or reduces Service for reasons other than a request by the Customer or an interruption of Service caused by the Customer's system, and the suspension or reduction results in a peak Demand which would otherwise be used for billing purposes, the Demand in the Demand Period immediately following restoration of service may be reduced, by mutual agreement, to an estimate of what the Demand would have been if Service had not been suspended or reduced. The estimate shall be determined in consideration of weather conditions and previous load experience.

9.06 Late Payments

If the amount due on any invoice has not been paid in full after twenty calendar days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in the Company's Electric Tariff, as amended from time to time.

9.07 Taxes

In addition to payments for electricity, the Customer shall pay to the Company the amount of any sales tax, goods and services tax, or any other tax or assessment levied by any competent taxing authority on any electricity delivered pursuant to this Agreement.

9.08 Payment of Accounts

The Customer shall pay to the Company the amount of the billing within 20 calendar days from the date appearing on the statement.

10. CONTINUITY OF SUPPLY

10.01 Standard of Performance

The Company shall perform the Services with skill, care, and diligence consistent with Good Utility Practice and consistent with directions from the Commission, including the quality performance standards, if any, approved by the Commission from time to time.

10.02 Interruptions and Defects in Service

The Company shall avoid interruption of delivery of electricity, but nevertheless shall not be liable to the Customer for any loss or damage owing to failure to supply electricity, or owing to other abnormal conditions of supply resulting from force majeure as defined in subsection 12.01.

10.03 Suspension of Supply

Either Party shall have the right to demand the temporary suspension of, or to suspend temporarily, the delivery or taking of electricity, as the case may be, whenever necessary to safeguard life or property, or for the purpose of replacing, repairing or maintaining any of its apparatus, equipment, or works. Such reasonable notice of the suspension as the circumstances permit shall be given by one Party to the other.

10.04 Discontinue Service

The Company may discontinue the supply of electricity to the Customer at a Point of Delivery for the failure by the Customer to commence remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any significant practice, term or condition to be observed or performed by the Customer under this Agreement. The Company shall be under no obligation to resume service until the Customer gives assurances satisfactory to the Company that the breach which resulted in the discontinuance shall not recur.

10.05 Obligations Continue

Discontinuance of Services by the Company pursuant to the provisions of this Agreement shall not relieve the Customer of any obligation under this Agreement, or alter any of the obligations of the Customer under this Agreement.

10.06 Other Remedies

The Company's right to discontinue the supply of electricity under this Agreement shall not operate to prevent the Company from pursuing, separately or concurrently, any other remedy it may have under this Agreement or by operation of law.

11. REMOVAL OF FACILITIES UPON TERMINATION

After the termination of this Agreement, the Company shall have the right to, and must expeditiously if requested by the Customer, remove from the property owned or controlled by the Customer any and all electrical apparatus and equipment which the Company owns and has installed on the property and the Company shall leave the property in good repair after such removal.

12. COFFEE CREEK SUBSTATION

12.01 Supply Equipment

The Customer takes delivery of electricity at the Coffee Creek Substation. The Customer has contributed transformers, metering units, reclosers, cables and other equipment necessary for the supply of electricity at 25 kV at the Company's substation located near Coffee Creek ("Coffee Creek Substation").

12.02 Transfer of Ownership

On June 30, 1997 the Customer transferred its interest in the equipment described in Section 12.01 to the Company so that all equipment on the line side of the Customer's disconnect switch 25D71 at the Coffee Creek Substation is owned solely by the Company, except for the Customer's check meter.

12.03 Operation and Maintenance Costs

The Company is responsible for all costs incurred to operate and maintain, and subject to section 12.04, replace as necessary, all equipment at the Coffee Creek Substation on the line side of the Customer's disconnect switch 25D71, except for the Customer's check meter..

12.04 Transformation Upgrades

Each party is entitled to the use of a 5 MVA share of the total transformation capacity of 10 MVA at the Coffee Creek Substation. Except in the event of an emergency condition, which event shall be governed pursuant to Section 6.03, if the Customer requires transformation capacity at the Coffee Creek Substation in excess of the Demand Limit, then the Company shall endeavor to provide the additional transformation capacity by the date the increase is required, or a soon thereafter as practicable. Notwithstanding Section 6.06, the total cost to increase the transformation capacity above the Demand Limit at Coffee Creek Substation shall be borne by the Customer.

12.05 Annual Payments

During the term of this Agreement, the Customer shall on June 30 of each year, pay to the Company, the sum of $5,000 in recognition of on-going operation and maintenance expense. If this Agreement expires prior to June 30 of any year of this Agreement, no amount will be payable in the year this Agreement expires.

12.06 Deemed Nominal Voltage

Notwithstanding that the nominal voltage supplied is 25 kV at the Coffee Creek Substation, the supply voltage to the Customer at the Coffee Creek Substation shall be deemed to be 63 kV for the purposes of determining applicable rates including, without limiting the generality of the foregoing, transformation and metering discounts, for purchases under this Agreement and Company rate Schedules 41 - Wholesale Service - transmission, Schedule 100 - Network Integration Transmission Service and Schedule 101 - Long-term and Short-term Firm Point-to-Point Transmission Service - Wholesale Customer not using Substation Equipment.

12.07 Coffee Creek Operating Order

The parties have agreed on an operating order for the Coffee Creek substation, as may be modified from time to time..

13. GENERAL PROVISIONS

13.01 Force Majeure

Neither Party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the Party prevented or delayed by that cause. If either Party is delayed or prevented from its performance at any time by any act, omission or neglect of the other Party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the Party or any unforeseeable cause beyond the control and without the fault and negligence of the Party, the Party so prevented or delayed shall give notice to the other Party of the cause of the prevention or delay but, notwithstanding giving of that notice, the Party shall promptly and diligently use reasonable efforts to remove the cause of the prevention or delay.

13.02 Notices

Any notice, direction or other instrument required or permitted to be given under this Agreement in writing shall be sufficient in all respects if delivered, or if sent by fax, or if sent by prepaid registered post in Canada to the Parties at their respective addresses as they appear in subsection 13.03, or to any substitute address of which the Party sending notice has had notice in writing.

13.03 Addresses

Any notice, direction or other instrument shall be delivered or sent to the following addresses:

(a) To the Company:
FortisBC Inc.
1290 Esplanade
PO Box 130
Trail, BC V1R 4L4
Attention: Secretary
Fax Number: 250-364-1270

(b) To the Customer:
General Manager
Nelson Hydro
502 Vernon Street
Nelson, BC V1L 4E8

13.04 Dates

Any notice, direction, or other instrument shall be deemed to have been received on the following dates if,

(a) sent by fax, on the business day next following the date of transmission.
(b) delivered, on the business day next following the date of delivery.
(c) sent by registered mail, on the fifth business day following its mailing, provided that if there is at the time of mailing or within two days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, directions or other instrument shall only be deemed to be effective if delivered or sent by fax.

13.05 Disputes

If any difference or dispute occurs regarding any matter arising under this Agreement, either Party may request that the Commission settle the difference or dispute. If the Commission declines to settle the dispute then the dispute shall be arbitrated pursuant to the Commercial Arbitration Act of British Columbia.

13.06 Invalidity

If any provision of this Agreement or the application of any provision to any Party or circumstance is declared or held to be wholly or partially invalid, this Agreement shall be interpreted as if the invalid provision had not been a part hereof so that the invalidity shall not affect the validity of the remainder which shall be construed as if this Agreement had been executed without the invalid portion. The Company and the Customer shall, either independently, jointly or in concert with other wholesale customers of the Company, make all reasonable efforts to validate any portion of this Agreement declared or held to be invalid.

13.07 Headings

The headings in this Agreement have been inserted for convenience of reference only, and shall not affect the construction or interpretation of this Agreement.

13.08 Enurement

This Agreement shall be binding upon and shall enure to the benefit of the Parties hereto and of their respective successors and assigns.

13.09 Governing Law

Notwithstanding anything to the contrary in this Agreement, this Agreement the Company shall comply fully with all applicable federal, provincial and municipal laws (including bylaws) in effect from time to time.

13.10 Entire Agreement

This Agreement and the Appendices attached hereto are intended by the Parties to be the final expression of their agreement and are intended also as a complete and exclusive statement of the terms of the Agreement.

13.11 Commission Approval

This Agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted from time to time and to the jurisdiction of the Commission.

This Agreement and subsequent amendments including changes to the Service Area, shall not be binding on the parties until it has been approved by the Commission.

IN WITNESS WHEREOF the Parties, by the signatures of their duly authorized officers set out below, have executed this Agreement.

The CORPORATION OF THE CITY OF NELSON this day 22 of DECEMBER, 2004 by

Marla Olson

Signature

Marla Olson
City Clerk

Title

Signature

Title

FORTISBC INC. this day 4 of April, 2005 by

Signature

Vice President, Customer & Corporate Services

Title

Signature

Title

This is Appendix A to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC Inc. and The Corporation of the City of Nelson

City of Nelson - Points of Delivery

1. **Rosemont Substation**

Description: Line side of the City of Nelson's No. 60D27 Disconnect Switch at Rosemont Substation

Nominal Voltage Supplied: 63 kV

Demand Limit:	Summer	40 MVA
	Winter	40 MVA

Alternative Point of Delivery: Line side of City of Nelson's disconnect No. 60D28 at Bonnington

2. **Coffee Creek Substation**

Description: Line side of City of Nelson's disconnect switch, designated 25D71, located on a pole adjacent to the Coffee Creek Substation

Nominal Voltage Supplied: 25 kV

Demand Limit:	Summer	5 MVA
	Winter	5 MVA

1.0 Reference: Energy Price
Exhibit No. C4-7, pp. 2-3
Average Amount

Q1.1 FortisBC states "First, it should be noted that the $45/MWh figure is an <u>average</u> amount". Please explain what is meant by an <u>average</u> amount of $45/MWh.

A1.1 As stated in BC Hydro's LTAP, page 4-18, line 14, "Monthly and yearly average prices are obtained by aggregating the computed hourly prices."

Q1.2 Confirm that FortisBC's average rate to Nelson is $53.7/MWh.

A1.2 Based on the City of Nelson 12 month 2007 billing data, FortisBC calculates the average rate based on 2009 rates to be $49.8/MWh.

Q1.3 Nelson, in Exhibit C8-7, p. 7, states the if Nelson was supplied by BC Hydro on RS 1823 Nelson's cost would be $44.6/MWh. Please confirm that Nelson's cost would be $44.6/MWh.

A1.3 Confirmed. This calculation has been performed based on FortisBC's interpretation of the BC Hydro tariff.

Q1.4 Can Nelson become a customer of BC Hydro? Please explain.

A1.4 Yes. Please see BCUC Order G-27-99, in particular Appendix A (Exhibit A-12), with respect to An Application by West Kootenay Power Ltd. for Approval of Access Principles. The City of Nelson is considered to be an Eligible Customer and, as such, can obtain all or part of its supply from non-Utility (FortisBC)

resources subject to the terms of the Access Principles Settlement Agreement.

Q1.5 If BC Hydro buys energy at $45/MWh and sells energy to FortisBC at $39.6/MWh then BC Hydro would net about -$5.4/MWh or -$2 million. Please confirm.

A1.5 Confirmed if the incremental volume includes both Celgar at 350 GWh and Nelson at 28 GWh.

Q1.6 If FortisBC sells energy to Nelson at $53.7/MWh and buys energy from BC Hydro at $39.6/MWh then FortisBC would net about +$14.1/MWh or +$5.4 million.

Q1.6.1 Please confirm that FortisBC would net about +$14.1/MWh.

A1.6.1 Not confirmed. FortisBC is not expecting any additional capacity payments from Nelson, only energy charges at $35.07 per MWh. In addition, FortisBC is not expecting to make any additional capacity purchases from BC Hydro on a planning basis (on an operational basis additional capacity purchases from BC Hydro may occur). FortisBC expects that its margin will be approximately $7 per MWh (based on a BC Hydro rate of $28.25 per MWh) on a volume of 25 GWh or about $175,000. If operational issues arise such that FortisBC pays BC Hydro incremental capacity charges, it is possible for the FortisBC net margin to be negative.

Please also refer to the response to BC Hydro IR3 Q2.10.

Q1.6.2 As FortisBC controls the timing of the sale, please explain when

Nelson might be expected to sell energy above or below a spot price of $53.7/MWh.

A1.6.2 FortisBC does not control the timing of the sale. The City of Nelson can elect to sell or not to sell as it wishes. If the City of Nelson elects to sell, FortisBC will examine the sale to see if FortisBC is harmed by the sale and choose to either allow it or not pursuant to the terms of the PCA. Therefore, sales will occur if the City of Nelson elects to sell and FortisBC is not harmed by the sale.

Q1.6.3 If these transactions which occur in real time are considered simultaneous, how would BC Hydro be expected to purchase energy at a price lower than that being sold by Nelson in the spot market? Please explain.

A1.6.3 FortisBC does not understand the question. Assuming the transactions referred to are a City of Nelson export and a BC Hydro import, is not correct to assume the transactions are simultaneous. Please also refer to the response to BCOAPO IR3 Q3.1.

Q1.7 FortisBC states "FortisBC believes that by making prudent buying decisions, BC Hydro could replace any requisite incremental energy at pri[c]es equivalent to, if not better than, the embedded cost price at which it would be selling energy to FortisBC under the PPA".

Q1.7.1 As FortisBC also purchases energy from other sources, please explain why FortisBC needs BC Hydro's energy to facilitate the UMBRELLA AGREEMENT.

A1.7.1 FortisBC does not currently possess the market trading resources that are available to BC Hydro through Powerex nor the system flexibility to absorb the required amounts of non-firm power. In addition, FortisBC and BC Hydro have agreed through the Canal Plant Agreement to place restrictions on the timing of FortisBC's market transactions that further limit its ability. Finally, the terms of the PPA itself would make it difficult for FortisBC to properly manage the level of market activity that would be required as the volume of buying activity would also require a certain level of sales activity to properly manage the portfolio.

Q1.7.2 As FortisBC also purchases energy from other sources, could FortisBC use the energy purchased from others to facilitate the UMBRELLA AGREEMENT. Please explain.

A1.7.2 Please refer to the response to BCUC IR3 Q1.7.1 above.

Q1.7.3 Please explain if there are any risks associated with the real time transactions that can occur to the BC Hydro Ratepayers if BC Hydro cannot secure energy pricing at $45/MWh.

A1.7.3 FortisBC does not believe BC Hydro has any capacity risk in the real time transactions whatsoever. The price of electricity has two components, an energy component and a capacity component. While power is normally traded at an energy price only, depending on the time of day there is an implied capacity value. This is why energy sold on the power markets in the daytime is generally sold at a higher price than energy sold at nighttime. However, even the energy sold at nighttime may have a capacity component built into the price—it is just harder to determine what it is. FortisBC believes that since BC Hydro

does not require replacement capacity, any replacement energy can be obtained with an effective capacity premium of zero.

However, FortisBC acknowledges that any forecast of prices is subject to uncertainty in the actual prices that will be realized. Therefore, despite the fact that BC Hydro will have a large amount of flexibility in the timing of the transactions to replace any incremental energy, it is possible that more than $45/MWh will be paid. If BC Hydro must pay more than $45/MWh, then FortisBC assumes there would be a risk of the increased costs flowing through to the BC Hydro ratepayer.

Q1.7.4 Please estimate the magnitude of the risk in dollars that could occur to the BC Hydro Ratepayers if BC Hydro cannot secure energy pricing at $45/MWh.

A1.7.4 The magnitude of the risk is directly related to the price BC Hydro must pay. BC Hydro has estimated that the volume risk is up to 378 GWh. If this is accepted as the upper limit of the volume risk, the financial risk is $378,000 for each additional $1/MWh that BC Hydro must pay. However, as stated above in response to BCUC IR3 Q1.7.3, BC Hydro has great flexibility in the timing of acquiring any replacement energy due to the fact that replacement capacity is not required. FortisBC expects that this flexibility will allow BC Hydro to largely, if not completely, mitigate any energy price risk.

Q1.7.5 Please explain if either FortisBC or Nelson could incur similar risks using BC Hydro PPA energy.

A1.7.5 No, since the BC Hydro PPA energy is at a fixed rate.

Q1.7.6 Considering the risk, and the return, why should BC Hydro ratepayers assume this risk? Please explain.

A1.7.6 BC Hydro is obligated under the 3808 PPA to supply up to 200 MW and associated energy for a 20 year term until 2013. The energy being supplied to FortisBC under the PPA is priced in accordance with the 3808 rates. BC Hydro assumed the risk of cost of supply of energy when agreeing to a 20 year term. The BCUC approved this agreement as being in the public interest. Note that BC Hydro faces and has accepted this price risk in supplying any incremental energy for the 3808 contract from the outset.

Q1.7.7 Please explain what risks FortisBC or Nelson could incur if FortisBC supplied energy purchased from others.

A1.7.7 FortisBC will not allow Nelson sales that materially negatively impact FortisBC, therefore, the risk is to Nelson and it is a volume risk.

Q1.8 FortisBC states "FortisBC does not believe that the long-term cost of new supply, used by BC Hydro to estimate its "opportunity cost" of providing replacement energy (see BC Hydro response to Commission IR 1.7.1.1), is a realistic proxy. FortisBC believes it is more appropriate to use the forecast cost of non-firm energy, since non-firm energy more closely resembles the energy BC Hydro might require to replace any energy exported by FortisBC customers".

Q1.8.1 Please provide that same calculations using the cost of non-firm energy as found in Order G-43-08, the 2008 Standing Offer Program. The table below is from G-43-08.

Revised Table 5-3 Base Price for Energy

	VI	LM	KN	CI	PR	NC	SI	EK
(7) Base Price 2007 $ (Unlevelized)	**83.23**	**82.87**	**79.36**	**76.62**	**69.11**	**70.53**	**71.42**	**75.15**
2007 to 2008 escalation (100% CPI)	*0.99*	*0.99*	*0.95*	*0.92*	*0.83*	*0.84*	*0.85*	*0.90*
Base Price (2008$)	***84.23***	***83.86***	***80.31***	***77.53***	***69.94***	***71.37***	***72.27***	***76.05***

A1.8.1 Please see the calculation below:

$72.27/MWh - $39.6/MWh = $32.67/MWh

and then

$32.67/MWh * 378,000 MWh = $12,349,260.

Note that the 2008 Standing Offer Program rates are well above the $45/MWh market based price found in the BC Hydro 2008 LTAP. Given that the Nelson sales are market based, it is not unreasonable that BC Hydro replace the Nelson energy from the market.

In addition, BC Hydro is assigning a capacity value to the 2008 Standing Offer Program power due to the varying time of day payments, (Standing offer program Rules, section 4.1). FortisBC maintains that capacity is not required to replace the Nelson energy. Please refer to the response to BCOAPO IR3 Q3.1.

2.0 Reference: Umbrella Agreement for Short-Term Firm or Non-Firm Point to Point Transmission Service Agreement dated April 18, 2008
Exhibit No. C4-3

"2.5 Nelson's Power Purchases from FortisBC.

Nelson will purchase from FortisBC, pursuant to Rate Schedule 41 of FortisBC's Electric Tariff B.C.U.C. No. 1 (as amended or replaced from time to time), any power Nelson requires to replace such Nelson Power as Nelson may have made available or agreed to make available to the Energy Marketer for sale pursuant to the Energy Marketing Agreement and that Nelson would otherwise have used to serve Nelson's load".

Q2.1 Can FortisBC replace such Nelson Power, as Nelson may have made available or agreed to make available to the Energy Marketer for sale, with purchased energy other than from BC Hydro RS 3808?

A2.1 Please refer to the response to BCUC IR3 Q1.7.1.

"2.9 Nelson Indemnity.

If, despite an election by FortisBC pursuant to Section 2.8(a) to require Nelson to use Available Nelson Power to serve Nelson load, Nelson instead uses such Available Nelson Power for a purpose other than to serve Nelson load (including by making such Available Nelson Power available to the Energy Marketer for sale pursuant to the Energy Marketing Agreement), then in such case (a "Nelson Decision") Nelson will indemnify and save harmless FortisBC from and against any and all losses, damages, expenses (including fees and disbursements of counsel), liabilities, costs, claims, suits, actions, demands, judgments, settlements and penalties of every kind, at any time suffer& or incurred by FortisBC, to the extent arising directly or indirectly from such Nelson Decision.

Other than as set out in the foregoing paragraph, Nelson will not be responsible or liable in any way to FortisBC for any consequence of Nelson dealing with Available Nelson Power as contemplated in this Agreement".

Q2.2 As FortisBC is a customer of BC Hydro, please explain why an agreement involving BC Hydro was not also considered by FortisBC.

A2.2 There was no need for an agreement with BC Hydro other than the ones that were already in place. Incremental power needs are identified by FortisBC and communicated to BC Hydro in accordance with the terms of the existing contracts and tariffs. BC Hydro has stated that it has no significant concerns with these notices. Please refer to BC Hydro's response to FortisBC IR1

Q1.5.2 (Exhibit B-7).

Q2.3 Please comment on the various following sections of the PCA that imply FortisBC's involvement in this export of energy.

Q2.3.1 Under Section 2.8 of the PCA, FortisBC controls the export of power available to serve the Nelson load.

A2.3.1 FortisBC has no ability to require Nelson to export power. Please refer to the response to BCUC IR3 Q1.6.2.

Q2.3.2 Under Section 2.10 of the PCA, FortisBC controls access to the requisite ancillary services to effect such sales through the Kootenay Interconnection.

A2.3.2 FortisBC is required to provide transmission service to Nelson. Provision of transmission service in no way implies that FortisBC is exporting the power.

3.0 Reference: Umbrella Agreement
Exhibit No. A-7, FortisBC August 14 Response, p. 5
Other Sources of Power

"FortisBC also maintains access to sources of power in addition to the BC Hydro PPA and may rely on multiple supply sources in order to serve the City of Nelson's incremental load requirements".

Q3.1 Instead of using BC Hydro RS 3808, is FortisBC willing to proceed with this Umbrella Agreement using access to other sources of purchased

power? If not, why not?

A3.1 In supplying customer load, FortisBC is obligated to utilize the most economic and reliable resources available to it. This includes the 3808 PPA and, most of the time, it is the preferred method of meeting FortisBC's incremental customer load. Should this resource not be available, FortisBC would continue to fulfill its obligation to supply its customers using the next best available resource and with respect to the City of Nelson exports, FortisBC would do so as per the terms of the Power Coordination Agreement. However, FortisBC's position on the required availability of 3808 power is clear.

Please refer to the responses to BCUC IR3 Q1.7.1, BC Hydro IR3 Q1.2 and CEC IR3 Q2.3 and Q3.13.

4.0 Reference: Nelson Supply Agreement
Exhibit No. C4-7, ATTACHMENT 3

Q4.1 Please provide an explanation of how nelson can export power under this supply agreement.

A4.1 The supply agreement requires electricity supplied by FortisBC to the City of Nelson to be used to meet City of Nelson load. Other than the demand limits, it makes no restriction on the volume of such supply. There is no requirement of the City of Nelson to use its owned generation to meet City of Nelson load nor is the City of Nelson's use of its owed generation even referenced. Please also refer to the response to BC Hydro IR3 Q8.3.

Q4.2 As FortisBC is a customer of BC Hydro, did FortisBC advise BC Hydro of Nelson Hydro's intention to export power?

A4.2 No. There was no requirement to do this other than through the normal course of business which is how BC Hydro became aware of the City of Nelson's exports. This activity was happening within existing tariffs and contracts so no special arrangements were required. The agreements associated with the City of Nelson exports were filed with the BCUC.

FortisBC provides an estimate of PPA usage to BC Hydro as part of the normal course of business. The current estimate of PPA usage provided to BC Hydro incorporates additional amounts estimated to be required as a result of Nelson exports. Please also refer to the response to BC Hydro IR3 Q1.5.

5.0 Reference: Arbitrage
Exhibit No. C4-7, p.1
Heritage Energy

Q5.1 Considering that FortisBC controls the timing of the exported energy and FortisBC wishes to determine how that energy is to be made up, is FortisBC effectively exporting this energy?

A5.1 No, FortisBC is not effectively exporting this energy. Nelson's export of its self generated electricity does not equate to FortisBC exporting.

Q5.2 Does FortisBC consider that heritage energy should form a part of this energy make up? Please explain.

A5.2 Yes, under the current contractual arrangements and tariffs.

FortisBC utilizes the 3808 PPA to serve FortisBC loads, including those of FortisBC's indirect customers serviced by the wholesale utilities. The pricing of

the 3808 PPA embeds the cost of production of BC Hydro's heritage assets and the incremental cost of new supply (through rate increases). Therefore, heritage energy forms part of the 3808 supply which is used to supply the City of Nelson load. FortisBC, as a BC Hydro ratepayer, is entitled to the benefit of heritage power as are all British Columbians. That benefit is passed through FortisBC to the City of Nelson customers.

The level of self generation that the City of Nelson chooses to or is forced to operate determines the load that FortisBC is obligated to serve. Regardless of what happens with the City of Nelson generation, FortisBC is obligated to serve the resulting load under Rate Schedule 41.

1.0 Reference: Exhibit C4-3, Power Coordination Agreement (PCA) between FortisBC and the City of Nelson dated as of May 14, 2008

Q1.1 Please confirm that FortisBC was approached prior to 2007 by a customer or customers with self-generation in connection with requests for replacement power to serve the customers' needs so that the customer or customers could export their self-generated power. Please explain why prior to May 2008 FortisBC did not agree to any such requests.

A1.1 Prior to 2007, West Kootenay Power was approached by Riverside Forest Products ("Riverside") with a request to sell incremental generation (which had yet to be built) to third parties. Subsequent to these discussions, Riverside made an application to the BCUC to sell incremental generation which was accepted on October 25, 2001 by Order G-113-01. Riverside built the new generation and was free to export that power and was not required to use it for self generation. Note that Riverside Forest Products is now known as Tolko Industries, and is a City of Kelowna customer.

FortisBC is not aware of any other self generation customer who requested such service prior to 2007.

Q1.2 Please explain why in 2008 FortisBC decided to agree to sell increased power to customers with self-generating facilities while those customers are exporting their self-generation not in excess of their loads.

A1.2 In 2008 FortisBC was approached by two of its self-generating customers with requests to increase their power purchases thus enabling them to export some or all of their internally generated electricity. Both entities were able to increase

their load and resulting power purchases under their existing tariffs without modification. As acknowledged by BC Hydro in its response to BCUC IR1 Q1.3.1 (Exhibit B-5), there were no restrictions on this type of transaction within existing tariffs, agreements, policies or programs. FortisBC was obligated to serve the resulting customer load and negotiated with each entity to ensure that FortisBC's remaining customers were not harmed by these transactions.

Q1.3 Does FortisBC consider that the principles of BCUC Orders No. G-38-01 and G-17-02 should not apply in FortisBC's service area? If not, what is different about FortisBC, its customers and/or its service area that renders the principles irrelevant? Does FortisBC agree that it could have sought an order from the BCUC under section 28(3) of the *Utilities Commission Act* relieving FortisBC from the obligation to provide replacement power to the City of Nelson and/or Zellstoff Celgar?

A1.3 FortisBC believes that its customer relationships, history, policies, programs and rate structures are fundamentally different than those of BC Hydro which led to the development of the referenced BCUC Orders. For example, FortisBC has not provided any subsidies or programs to any self generators that would give the utility the right to negotiate some form of commitment to self generate. Referring to FortisBC's response to BC Hydro IR3 Q1.2 above, prior to proceeding with these arrangements, FortisBC conducted the necessary contractual and regulatory due diligence related to the proposed transactions. There was no compelling reason for FortisBC to deny the requests of these customers since it appears, and it has been confirmed by BC Hydro, that these customers were within their rights to request this additional service.

Q1.4 Did FortisBC ask BC Hydro whether it would have any concerns about the proposed arrangements to allow customers with self-generation to export

power while relying on increased energy purchases under the PPA to provide replacement energy to serve load?

A1.4 FortisBC did not ask BC Hydro prior to the City of Nelson proceeding with export transactions, nor did it have an obligation to do so.

Q1.5 Did FortisBC consider whether the increased power flows resulting from the new arrangements with the City of Nelson and Zellstoff Celgar would be planning and/or operating information that BC Hydro would reasonably require (under section 5.1 of the RS3808 Power Purchase Agreement (PPA)) for the timely and efficient performance of its obligations under the PPA? If not, why not?

A1.5 Yes. However, it must be noted that only the City of Nelson transaction has been allowed to proceed and involves a relatively small amount of power which puts it in the realm of normal variations in load for which the notice provisions of the 3808 PPA are set up. FortisBC has complied with these notice provisions (such as capacity nominations and prescheduling of energy), the purpose of which is to provide BC Hydro with adequate notice of FortisBC's requirements.

In response to FortisBC IR1 Q1.5.2 (Exhibit B-7), BC Hydro states in part: "….BC Hydro has no significant concerns with respect to FortisBC's provision of Reservations and Nominations (specified under section 7 of the PPA), or Prescheduling and Energy Accounting obligations (specified under section 8 of the PPA)."

The Celgar Agreement (involving the export of Celgar's self generation) is fundamentally different and more complex than the City of Nelson Power Coordination Agreement, and also involves a larger amount of power.

Therefore, both Celgar and FortisBC agreed that this Agreement would be filed with the BCUC for approval prior to transacting. The application for approval of the Agreement between Celgar and FortisBC was submitted, however, that application was withdrawn by FortisBC on September 29, 2008 pending resolution of this BC Hydro application to amend the PPA. If and when the Celgar Agreement Application is refiled, then the subsequent regulatory proceeding will provide BC Hydro and others an opportunity to intervene. This process would have and has provided BC Hydro with ample notice of this potential transaction.

2.0 References: Exhibit C8-7 at page 15 "At that time there was no FortisBC opposition to our initiative, only the caveat that FortisBC's customers should be, as a minimum, held harmless as a result of our activities." Exhibit C4-3, PCA section 2.8(a)

Q2.1 Please confirm that FortisBC believes that it and its customers should be, as a minimum, held harmless as a result of the City of Nelson's export activities.

A2.1 In principle, yes. This was FortisBC's negotiating position when initially approached by the City of Nelson with its self generation export proposal. However, since the City of Nelson was operating within all existing tariffs and contracts, there was no absolute requirement for this.

Q2.2 Please explain how the PCA ensures that the City of Nelson's exports do not occur in a manner that would harm FortisBC or its customers.

A2.2 Under the PCA, FortisBC may, "Require Nelson to use the Available Nelson Power specified in such Availability Notice to serve Nelson load, to the extent

that FortisBC would incur a loss to replace such Available Nelson Power…" (Clause 2.8 (a) PCA). Essentially, if FortisBC believes that the export the City of Nelson proposes to make in the Availability Notice required by the PCA is going to occur at such a time as to cause FortisBC loss, then FortisBC will require Nelson to use the proposed export to meet Nelson load instead. However, this does not completely ensure that no harm will occur as FortisBC operating personnel could inadvertently allow an export that causes FortisBC loss due to either error or variances between actual and forecast conditions. However, as FortisBC expects to earn a small positive margin on the increased Nelson load, this, combined with the above, ensures no harm. Please also refer to the response to BC Hydro IR3 Q2.10 below.

Q2.3 Does FortisBC agree that it is a customer of BC Hydro pursuant to the PPA, and that the City of Nelson and Zellstoff Celgar are indirect beneficiaries of low cost PPA power?

A2.3 Yes.

Q2.4 Does FortisBC agree that BC Hydro's direct customers, and FortisBC customer who are indirect beneficiaries of low cost PPA power, should also be held harmless as a result of the export activities of FortisBC's customers with self generation? If not, why not?

A2.4 It is important to note that BC Hydro's incremental cost of acquiring power to meet load growth is reflected in its annual revenue requirements. FortisBC pays for its share of that incremental revenue requirement through BC Hydro rate increases which are applied to the 3808 rate class similar to any other BC Hydro rate class. In this sense, BC Hydro's customers are being kept whole.

BC Hydro executed the 3808 PPA for a period of 20 years and have acknowledged that there is no existing restriction within the 3808 PPA that would prevent FortisBC from purchasing 3808 power and reselling it to its customers, whether those customers be self generators or not. In making this 20 year contractual commitment, BC Hydro, as a sophisticated party to this agreement, would have assessed the sensitivities of cost and amount and timing of power deliveries for this entire period. In fact, given the difficulty with predicting load growth and power prices adequately, BC Hydro would have had to consider, and accept that it may be required to deliver up to the full amount of capacity and energy under the term of this contract and may have to procure power at costs that were much different than anticipated. This contractual obligation is one that BC Hydro undertook. In doing so, it must also accept the contractual risk of providing the amount of power that FortisBC calls for, within the physical limits of the contract, at the agreed upon price. There is no provision in the 3808 PPA to enable any form of direct flow through of specific incremental costs that BC Hydro may incur. Instead, FortisBC assumes BC Hydro pools those costs, as it does for all its other customers with increasing load consumption, and recovers those costs through general rate increases.

Q2.5 Is FortisBC concerned about increases in the rates it pays for the energy it purchases from BC Hydro under the PPA?

A2.5 FortisBC's customers appreciate the relatively low cost of the power that FortisBC receives under this contract and its predecessors. FortisBC customers also appreciate that they have been recognized as having the same rights as all British Columbian ratepayers with respect to being entitled to some of the benefits of low cost electricity produced by heritage assets (many of which are situated in FortisBC service territory).

FortisBC is very concerned with the large rate increases that BC Hydro has recently filed for in its 2009/2010 RRA. BC Hydro's rate increases are applied directly to the 3808 power purchases which account for 20 percent of FortisBC's entire revenue requirements.

Q2.6 Does FortisBC agree that if BC Hydro incurs incremental costs because of the export activities of FortisBC's customers with self generation, then those costs should be recovered from BC Hydro's customers? If not, why not?

A2.6 Please see the response to BC Hydro IR3 Q2.4 above.

Q2.7 Does FortisBC agree that if BC Hydro incurs incremental costs because of the export activities of FortisBC's customers with self generation, then BC Hydro would need to either increase its rates, including the RS 3808 rates, or maintain its rates higher than they would otherwise be? If not, why not?

A2.7 Please see the response to BC Hydro IR3 Q2.4 above.

Q2.8 Does FortisBC agree that if BC Hydro incurs incremental costs because of the export activities of FortisBC's customers with self generation, then those export activities would harm the customers of both BC Hydro and FortisBC? If not, why not?

A2.8 Please see the response to BC Hydro IR3 Q2.4 above, and Q2.10 below.

Q2.9 Does FortisBC consider that any customer of BC Hydro or FortisBC that has its own generation should be able to do what the City of Nelson is

currently permitted to do under the PCA?

A2.9 FortisBC is not in a position to determine how BC Hydro's customers with self generation should be handled since their situation is fundamentally different than that in the FortisBC service territory. Please see the response to BC Hydro IR3 Q1.3 above.

Q2.10 Does FortisBC agree that it would profit from the arbitrage activities of the City of Nelson and Zellstoff Celgar as described in BC Hydro's response to BCUC IR 1.5.3 (Exhibit B-5)? If not, why not? Would FortisBC also profit from the charges for transmission wheeling and ancillary services? Do FortisBC's current rates reflect the incremental revenues it is receiving from the City of Nelson?

A2.10 The City of Nelson export activities should occur in such a manner that results in a small positive margin for FortisBC ratepayers. This is how FortisBC is able to achieve a 'no harm' situation. However, the amount of the margin will be affected based on rate increases and differentials between BC Hydro and FortisBC and by 3808 surcharges. Please also refer to the response to BC Hydro IR3 Q2.2 above.

The City of Nelson's expected export activities have been forecast in FortisBC's 2008 and 2009 Revenue Requirements. The forecast of costs and revenues and margin were provided in the response to BCUC IR1 Q43.1 in the FortisBC 2009 Revenue Requirements proceeding. An excerpt of that response is provided here (without the supporting tables). Please note that the $0.124 million is before the required adjustments for the negotiated settlement. Please also refer to the response to BCUC IR3 Q1.6.1.

Q43.1 Please explain how the Nelson Hydro export program will impact FortisBC net revenues in 2009.

A43.1 Forecast net annual gains are expected from the additional sales to Nelson Hydro in the amount of $0.090 million for 2008 and $0.124 million for 2009. If Nelson Hydro ceases to export the forecasted portion of their generation, these net gains will not occur. The Company will be applying to recover this amount as a flow through charge to 2010 depending on the results of the current BCUC proceedings on this matter.

The financial outcome of the proposed Celgar exports is much more difficult to predict due to the nature of the supply being flatter and year round and likely requiring market purchases. Any forecast of margin over a long term contract would be highly dependent on assumptions that are variable. The intent of the Celgar agreement is to keep FortisBC customers whole over the term of the contract.

Regarding BC Hydro's question regarding 'profit' from transmission tariff revenue, as BC Hydro is well aware, transmission tariff revenue is not 'profit' and is designed to recover the cost of providing transmission wheeling and ancillary services.

Q2.11 If FortisBC would profit from the arbitrage activities of the City of Nelson and/or Zelstroff Celgar, how would this profit be distributed between: 1) FortisBC Ratepayers, and 2) FortisBC Shareholders?

A2.11 As stated in the response to BC Hydro IR3 Q2.10 above, the margins are forecast into 2009 rates and are fully to the benefit of FortisBC customers.

Other than BC Hydro rate changes, which are accorded flow-through treatment in rates, any variances, positive or negative, from the forecasts will be subject to sharing (an an after-tax basis) between FortisBC's customers and Shareholder under the terms of the Performance Based Regulation mechanism in place.

It is anticipated that the treatment of Celgar revenues and costs would be dealt with in a regulatory proceeding subject to filing of that agreement for approval with the BCUC.

Q2.12 If FortisBC where to acquire additional rate-base assets to serve additional customer loads, please provide a forecast of the regulated rate of return on equity that FortisBC shareholders would realize.

A2.12 FortisBC considers this question to be irrelevant to this proceeding. Current regulated rates of return are available in the public domain. Currently the ROE is formulaic and dependent on long term interest rate forecasts.

Q2.13 If arbitrage exports were to fully utilize the PPA energy available under the 200 MW PPA capacity limit, would FortisBC then serve its incremental load growth via investments in rate-base assets?

A2.13 FortisBC currently provides well over 20 percent of its peak demand through market based purchases of power and is working towards defining solutions that would enable it to be less exposed to the market and more self sufficient. There exists a current need to firm up FortisBC supply stack now. Incremental supply options include long term PPA's (including the renewal of the 3808 PPA), potential ownership of generation assets and market based instruments. How FortisBC ultimately meets its current load/resource gap and incremental

load growth will be determined in the regulatory process that will occur upon filing of FortisBC's Resource Plan.

3.0 Reference: Exhibit C4-7 at page 1, Background. FortisBC states that "British Columbia Hydro and Power Authority ("BC Hydro") <u>alleges</u> that the export activities of certain FortisBC customers who have self-generation capabilities <u>will oblige</u> BC Hydro to provide incremental energy to FortisBC pursuant to the PPA, at embedded cost rates, to replace the exported energy." [emphasis added]

Q3.1 Is FortisBC implying that it believes that BC Hydro would not have to provide incremental energy to FortisBC under the PPA at embedded cost rates to replace the energy that is exported by the City of Nelson not in excess of its load? If so, please explain the basis for FortisBC's understanding. If not, what is the statement meant to imply?

A3.1 No. The statement is FortisBC's characterization of BC Hydro's assumptions as FortisBC understands them. There is no hidden meaning.

Q3.2 How many FortisBC customers have their own on site generating facilities (including the City of Nelson and Zellstoff Celgar)? What is the total nameplate capacity of those generating facilities?

A3.2 FortisBC is not aware of any FortisBC customers that have on site generating facilities (other than back-up generators) other than the City of Nelson, Zellstoff Celgar and the City of Kelowna. Total approximate current nameplate capacity would be 50 MW for Celgar, 15 MW for Nelson and 0.09 MW (90 KW) for the City of Kelowna. In addition, there are several small IPP's within the FortisBC service area that sell power to FortisBC or directly to market with an aggregate

generation total of about 1 MW.

The only other possibility that FortisBC is aware of would be Tolko Industries, a City of Kelowna customer, as outlined in response to BC Hydro IR3 Q1.1 above. Total nameplate capacity is about 14 MW, however, only 6 MW is available (please see the response to BC Hydro IR3 Q3.3 below).

Q3.3 Has FortisBC been approached by any other customers with self-generation (other than the City of Nelson and Zellstoff Celgar) in connection with the possible export of all or a portion of their self-generation? What is the potential amount (in MWh/year) of increased load to FortisBC if all of its customers with self-generating facilities export all of their self-generated power? If any other FortisBC customers with self-generation were to request additional service for the purpose of exporting their self-generation, does FortisBC believe it has the discretion to deny such service? If so, why and under what circumstances?

A3.3 Tolko Industries has the right to export 4 MW of the 6 MW generated amount and to take the balance of its load under City of Kelowna rates. Tolko Industries has not exercised its rights to the best of FortisBC's knowledge. FortisBC notes that Tolko is a City of Kelowna customer. Assuming the 4 MW export is constant over an entire year, the total volume of exports is 35,040 MWh/year. FortisBC expects the City of Nelson exports to total 25,000 MWh/year and the Zellstoff Celgar exports to total 350,000 MWh/year. City of Kelowna exports could likely be about 500 MWh a year but with only 0.09 MW, it is very unlikely any export schedules will occur.

Please also see the response to BC Hydro IR3 Q1.1 above.

If a customer with self generation is operating within the established tariffs, contracts and laws then FortisBC does not believe it has the discretion to unilaterally restrict the customer's export of self-generated power. However, if there was potential material harm to FortisBC's customers as a result of this action, FortisBC would attempt to negotiate a balanced solution with the customer as it has done with the City of Nelson and Celgar.

4.0 References: Exhibit B-5, the response to BCUC IR 1.7.1.1

Exhibit B-9, the response to BCOAPO IR 2.3.2

Exhibit C4-7 at page 2, (a) Cost to BC Hydro of replacement energy. FortisBC states that it does not believe that BC Hydro's long-term cost of new supply is a realistic proxy for BC Hydro's opportunity cost of providing replacement energy.

Attached is Ministerial Order M271 issued on November 7, 2008 (DSM Regulation). Section 4(3) of the DSM Regulation states that "in determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority".

Q4.1 Please confirm that under the DSM Regulation "the authority" refers to BC Hydro, and that FortisBC is a "bulk electricity purchaser".

A4.1 Confirmed.

Q4.2 Please confirm that under subsection 4(3) of the DSM Regulation, BC Hydro's long-term marginal cost of acquiring new electricity, rather than the actual price FortisBC pays for energy purchases from BC Hydro, is to be used when the BCUC and FortisBC are evaluating FortisBC's DSM programs as to their cost effectiveness. If not confirmed, please explain why not.

A4.2 The cost effectiveness of FortisBC's DSM programs will be evaluated using FortisBC's long term marginal cost. Purchases from BC Hydro are a component of FortisBC's cost of acquiring new electricity. The BC Hydro component will be valued at BC Hydro's long-term marginal cost.

Q4.3 Does FortisBC accept that BC Hydro's long-term marginal cost of acquiring new electricity is prescribed by subsection 4(3) of the DSM Regulation to be the avoided supply cost because increased purchases by FortisBC under the PPA may require BC Hydro to acquire new resources at its long-term marginal cost of acquiring new electricity? If not, why not?

A4.3 No. In FortisBC's opinion, Section 4(3) of the DSM Regulation applies only to the evaluation of DSM programs and is intended to provide consistency when evaluating the DSM programs of different utilities. FortisBC does not accept that the principle is generally applicable to the PPA because BC Hydro has an obligation under the PPA to supply FortisBC at embedded rates subject to the 200 MW capacity limit.

5.0 References: Exhibit C4-4 at page 2, FortisBC response to BCUC IR 3

Exhibit C4-7 at page 2, (a) Cost to BC Hydro of replacement energy.

FortisBC states that it is more appropriate to use the forecast cost of non-firm energy, since non-firm energy more closely resembles the energy BC Hydro might require to replace any exported by FortisBC customers. FortisBC also states BC Hydro has confirmed that City of Nelson exports do not change the magnitude of the capacity reservation held by BC Hydro on its system.

Q5.1 Please confirm that under sections 8.1 and 8.2 of the PPA, FortisBC is required to preschedule its energy requirements, and that under section 8.3 of the PPA any requirements that exceed the amount prescheduled for any hour shall be considered "Excess Energy" for that hour, and shall be subject to an increased energy charge.

A5.1 Confirmed.

Q5.2 Please confirm that the majority of the replacement power ForitsBC would provide to the City of Nelson and/or Zellstoff Celgar would be from increased purchases under the PPA. If not confirmed, please explain.

A5.2 Confirmed.

Q5.3 Please confirm that section 6.1 of the PPA states that, BC Hydro shall "subject to Section 2.1, deliver energy to [FortisBC] with associated capacity at all times and such capacity shall be used in the determination of billing demand. [FortisBC] shall not take delivery of energy without associated capacity." Please confirm that all energy FortisBC purchases from BC Hydro under the PPA includes the associated capacity at all times.

A5.3 Confirmed.

Q5.4 Does FortisBC believe that the energy it purchases from BC Hydro under the PPA, including energy it purchases to provide replacement energy to customers exporting self-generated power, is or can be non-firm or "capacity free"? If so, please explain.

A5.4 No.

Q5.5 If FortisBC believes the energy it purchases from BC Hydro to provide replacement energy to the City of Nelson is non-firm, then does FortisBC agree that BC Hydro should only be obligated to provide such energy as and when available and so long as there is no financial loss to BC Hydro?

A5.5 Please refer to the response to BC Hydro IR3 Q5.4 above.

Q5.6 Please confirm that there is no BC Hydro tariff or rate schedule under which FortisBC may purchase non-firm energy from BC Hydro. If not confirmed, please explain.

A5.6 Confirmed.

Q5.7 Does FortisBC provide non-firm energy to the City of Nelson under the Agreement for the Supply of Electricity Wholesale Service dated November 1, 2004?

A5.7 No.

Q5.8 Please confirm that section 2.6 of the PCA provides that any and all power purchased pursuant to the PCA shall be used to serve the City of

Nelson's load. Does FortisBC provide non-firm energy to the City of Nelson under the PCA to serve the City of Nelson's load?

A5.8 Confirmed. FortisBC does not provide non-firm energy to the City on Nelson.

Q5.9 Does FortisBC agree that if it increases its purchases from BC Hydro under the PPA to provide increased, replacement power to exporting customers with self generation, it would purchase more capacity and energy (and BC Hydro would have to accordingly provide more capacity and energy) than it would otherwise?

A5.9 FortisBC does not agree. FortisBC confirms that FortisBC will purchase more capacity and energy and that BC Hydro will have to provide more energy and billed capacity. However, the amount of unbilled capacity that BC Hydro sets aside and reserves on the BC Hydro system (but does not bill for) under the terms of the PPA will be reduced by the amount of the increased billed capacity. Therefore, the amount of capacity that BC Hydro must utilize (either to meet generation requirements or to meet potential generation requirements) does not change as confirmed by BC Hydro in its response to FortisBC IR2 Q2.6.1 (Exhibit B-9). Please also refer to FortisBC's response to BCOAPO IR3 Q3.1a.

Q5.10 Please provide further explanation why the cost of non-firm energy is an appropriate proxy for the cost BC Hydro would incur to supply firm energy and capacity to FortisBC for the purpose of serving FortisBC's and the City of Nelson's service area load.

A5.10 FortisBC maintains that because the City of Nelson exports do not require FortisBC to exceed the 200 MW limit under the PPA, which BC Hydro has

confirmed is continuously held available on the BC Hydro system, there is no incremental capacity associated with the replacement power. Please see the response to CEC IR3 Q6.1.

BC Hydro's contention that there is a capacity impact from the Nelson exports leads FortisBC to assume that BC Hydro may either not currently be setting aside the required capacity to fulfill the PPA obligations or may actually be setting too much system capacity aside. While FortisBC does not know which situation may be occurring, either could result in BC Hydro being concerned about capacity. It may also be possible that BC Hydro has some method that FortisBC is not familiar with for using the same capacity twice, allowing BC Hydro to both export the capacity and hold it in reserve to fulfill its PPA obligations.

Until BC Hydro acknowledges FortisBC rights under the PPA to the full amount of nominated capacity at any time and without notice, FortisBC must contend that any replacement energy BC Hydro may acquire is non-firm or even interruptible.

If, as noted in the response to CEC IR3 Q6.1, BC Hydro is reserving excess capacity as a result of its interpretation of the PPA operating requirements, then, as anticipated in the PPA, such issues of interpretation are to be resolved by the existing PPA Technical Committee. FortisBC restates its desire to work with BC Hydro to understand this issue and to ensure that the correct amount of capacity is being held on the BC Hydro system as required by the PPA.

Please also refer to the responses to BC Hydro IR3 Q5.9 above and BCOAPO IR3 Q3.1.

6.0 Reference: Exhibit C4-7 at page 2, (c) FortisBC's calculation (before adjustment). FortisBC references the mid-forecast of $45/MWh from BC Hydro's 2008 LTAP Application.

Q6.1 Please confirm that the $45/MWh value is the annual, average hourly price for energy only and does not include transmission costs.

A6.1 The $45/MWh value is taken from the BC Hydro LTAP and represents the Mid-C price. FortisBC is not able to determine from the BC Hydro LTAP if the presented numbers were adjusted for transmission or not.

Q6.2 The City of Nelson states in Exhibit C8-7 at page 7 that its load factor is "quite low". Please confirm that the City of Nelson's load factor would be approximately 50 per cent assuming energy sales and purchase of replacement power from FortisBC.

A6.2 Based on 2007 actual City of Nelson loads, the load factor was 38 percent. FortisBC confirms that with an additional 25 GWh of City of Nelson load, but no change in peak load, the load factor is about 50 percent.

Q6.3 Does FortisBC contend that the annual, average hourly price is the appropriate cost to serve the City of Nelson's load shape? Does FortisBC contend that the annual, average hourly price at Mid-C is representative of the cost BC Hydro would actually incur to indirectly supply replacement power to serve the City of Nelson's load?

A6.3 FortisBC rates to serve customer loads are not based on that customers load shape but on average utility costs. Therefore, it would be incorrect for FortisBC to base the City of Nelson rates on anything other than average utility costs.

Until the City of Nelson began exporting power, its existing generation met a substantial portion of the City of Nelson's base load requirement. The remaining load requirement was of poor load factor. An average annual rate would not be a good representation of the cost to serve this load. However, the incremental load that FortisBC expects to serve under the current situation with the City of Nelson exporting is the base load component that the City of Nelson was previously self-supplying. Since the City of Nelson fully expects to continue to self-supply during periods of high demand, FortisBC is not expecting any increased peak requirements. Therefore, the average annual price would actually be expected to be higher than the cost to serve the incremental City of Nelson load.

Q6.4 Does FortisBC contend that BC Hydro could import energy from Mid-C to provide incremental power to FortisBC under the PPA which FortisBC in turn provides to the City of Nelson as replacement power, while at the same time the City of Nelson exports to Mid-C using the services of NorthPoint, and that all parties involved in the series of transactions would make a profit?

A6.4 Since the incremental power that BC Hydro must replace is non-firm, it is not necessary to replace the power at the same time. Therefore, FortisBC does contend that it is possible that BC Hydro may be able to replace the energy at a profit, or at the very least, at rates substantially below BC Hydro's estimated costs to do so.

Q6.5 If the analysis outlined in Exhibit C4-7 is correct, then why would FortisBC, the City of Nelson and/or Zellstoff Celgar need to include BC Hydro and the PPA in the transaction? Why would FortisBC not purchase

from Mid-C directly and provide the replacement power to the City of Nelson/Zellstoff Celgar without relying on PPA purchases? Why does the arbitrage transaction need to involve BC Hydro at all?

A6.5 Please refer to the response to BCUC IR3 Q1.7.1.

Q6.6 Please provide a calculation similar to that presented in Exhibit C4-7, but assuming FortisBC buys at Mid-C the energy necessary to provide the replacement energy to the City of Nelson and Zellstoff Celgar, and without any involvement of BC Hydro or the PPA. Please explain whether FortisBC would profit from the transactions. If not, please explain what is missing from the analysis in Exhibit C4-7.

A6.6 As explained in the response to BCUC IR3 Q1.7.1, FortisBC feels it has neither the resources nor the contractual flexibility under its agreements with BC Hydro to engage in this level of market based transactions.

7.0 Reference: Exhibit C4-7 at page 2, (d)(i) market trading efficiency factor

Q7.1 Please confirm that FortisBC meant that "Powerex" is generally regarded as one of the most skilled and accomplished energy traders in North America, and that the reference to "BC Hydro" is not correct.

A7.1 FortisBC notes that Powerex is a wholly owned subsidiary of BC Hydro. FortisBC understand that the Powerex trading expertise is fully available to BC Hydro as required.

Q7.2 Please provide any supporting evidence FortisBC has to justify the assertion that Powerex can achieve a 10 per cent efficiency advantage

over the annual, average hourly price of energy forecast as described in section 4.4.1 of the 2008 LTAP (attached to Exhibit C4-7).

A7.2 It has been FortisBC's experience that its transactions with Powerex generally occur at either above the hourly market price if FortisBC is buying or below market if FortisBC is selling. FortisBC is prepared to pay this premium because of the superior reliability and availability of the BC Hydro power. Based on industry discussions, FortisBC believes other market participants have the same experience.

However, more directly, a market average is just that, an average. As discussed above, FortisBC believes BC Hydro has great flexibility in the timing of acquiring replacement power since it can be done on a non-firm or even interruptible basis and can therefore achieve a result better than average. FortisBC maintains that Powerex has the demonstrated skills and ability to achieve this.

Q7.3 Why does the FortisBC evidence attribute no cost to the alleged market trading efficiency benefit?

A7.3 FortisBC is not able to estimate this cost, if there is any incremental cost at all.

Q7.4 Does FortisBC assert that BC Hydro should use the limited capability of the system to import economic energy, to benefit customers with self-generation that wish to arbitrage embedded cost-based rates (such as the City of Nelson and Zellstoff Celgar) rather than using that capability for the benefit of all of BC Hydro's customers (including FortisBC's customers indirectly)? Does FortisBC assume that BC Hydro does not already use the full capability of the system to import economic energy

for the benefit of all of its customers? If so, please provide a detailed explanation of the basis for the assumption.

A7.4 FortisBC notes that BC Hydro has recently entered into agreements or has made calls for power that include large amounts of energy. It seems reasonable to believe that BC Hydro continues to have flexibility to absorb this power. Since the power under examination here totals only 378 GWh, FortisBC finds it doubtful that any significant system limitations are present beyond those BC Hydro is already dealing with due to its ongoing power acquisition efforts. Therefore FortisBC expects BC Hydro to use its available resources to the best of its ability to reduce the incremental cost as much as possible. While FortisBC does not manage the BC Hydro system and therefore is not in a position to calculate this cost as accurately as BC Hydro could, FortisBC felt it necessary to enter a possible calculation due to the decision of BC Hydro not to do so as presented in the response to BCOAPO IR2 Q2.3.3 (Exhibit B-9).

8.0 Reference: None.

Q8.1 Please provide any documentation FortisBC has that demonstrates BC Hydro or the BCUC knew or ought to have known in 1993 that FortisBC would seek to purchase energy under the PPA to serve customers with self generation while the customers export energy not in excess of their load.

A8.1 In 1993, the City of Nelson's generation did exist and had existed for some time. Celgar has self generated since 1959 at a level of about 4 MW and completed building its current generation capability of about 50 MW in 1993. Prior to 1993, electric industry reform (unbundling, retail competition, open

access) was proceeding in several jurisdictions (e.g. the UK, U.S., Norway). The U.S. Energy Policy Act, which established a new era in electricity and addressed competition and open access, was enacted into law in 1992 in the US. All of this was generally known throughout the electrical industry and was discussed openly.

BC Hydro was a sophisticated party to the 3808 PPA and saw fit to ensure there were restrictions in place that would prevent FortisBC from exporting 3808 power. It is not unreasonable to suggest that BC Hydro could have anticipated that, over a 20 year term, and with the beginnings of electrical industry restructuring occurring, there could be some chance for self generation to find more beneficial ways to use their power other than to offset power purchases.

As BC Hydro admits, there are no restrictions in the 3808 PPA which prevents this type of activity from occurring. FortisBC assumes BC Hydro acted prudently in its negotiations and the due diligence relating to the negotiations. The contract was also filed with the BC Utilities Commission.

Q8.2 Please reference all passages in the BCUC's April 1993 decision regarding the PPA that indicate the intent of the PPA was to allow FortisBC to take energy under the PPA to serve a customer that is exporting its own generation.

A8.2 Please see the response to BC Hydro IR3 Q8.1 above.

Q8.3 Please reference any provisions in the PPA that expressly permit FortisBC to take energy under the PPA for the purpose of providing replacement power to a customer that is exporting its own generation not

in excess of its load.

A8.3 Please see the response to BC Hydro IR3 Q8.1 above and BC Hydro's response to FortisBC IR1 Q1.1.1. BC Hydro and FortisBC agree that there has been no breach of the 3808 PPA. The PPA and the Power Coordination Agreement expressly state that the power purchased by FortisBC and subsequently purchased by the City of Nelson is to be used to serve its native loads. It is FortisBC's understanding that both parties are in compliance with that requirement.

Q8.4 Please provide copies of FortisBC's bills to the City of Nelson for August and September, 2008 for purchases under the PCA, purchases under the Agreement for the Supply of Electricity Wholesale Service between the City of Nelson and FortisBC dated as of November 1, 2004, and charges under the Umbrella Agreement.

A8.4 Please see BC Hydro Appendix A8.4. Please note that FortisBC has no provision under its tariff to bill for transmission level wheeling losses. Losses are to be supplied and the City of Nelson is indeed doing so. The billing will be corrected.

Q8.5 Please provide copies of sample ETAGS in connection with the City of Nelson wheeling its energy through the FortisBC transmission system.

A8.5 Please see BC Hydro Appendix A8.5.

Q8.6 Now that FortisBC has customers purchasing transmission wheeling services, does FortisBC plan to develop an open access same-time information system (or OASIS)? If not, why not?

A8.6 FortisBC does not understand the relevance of this question to the current proceeding. FortisBC agrees that OASIS may be necessary at some point in the future. However, FortisBC does not feel it is necessary at this time as there is sufficient transmission capacity to meet all requests FortisBC has received.

FORTISBC

FortisBC Inc.
PO Box 8970, Station Main, Vancouver, BC V6B 4E2
Telephone: 1-866-4FORTIS (1-866-436-7847)
www.fortisbc.com

Account Name: NELSON HYDRO
Billing Date: SEP-22-2008
Billing Period: JUL-31-2008 to AUG-31-2008

7609315215-5
OCT-16-2008
Amount to be Withdrawn
$355,025.85

Previous statement	678,277.53	
Payment received Sep-19-2008 — Thank you	328,188.31CR	
Balance outstanding		**350,089.22**

Current Electric Charges

1 DAM SUBSTATION CR
(Meter 898051)
(Meter 898049)

0.00

1 DAM SUBSTATION
(Meter 898049)
(Meter 9999998)
(Meter 898051)
(Meter 924185)

Wholesale Rate reversed	
Basic Customer Charge reversed	3,667.74CR
Energy Used: 3,777,948 kWh @ $0.03507/kWh reversed	132,492.64CR
Demand Charge Based on January reversed	
Billed Demand 18,916.5 kVA @ $4.12/kVA reversed	77,935.98CR
Interim Rate Increase reversed	1,712.77CR
Wholesale Rate	
Basic Customer Charge	3,667.74
Energy Used: 3,777,948 kWh @ $0.03507/kWh	132,492.64
Demand Charge Based on January	
Billed Demand 18,916.5 kVA @ $4.12/kVA	77,935.98
Interim Rate Increase	1,712.77
	0.00

Meter Reading Information

Meter Number: 898051

Aug	31 2008	00001.283	
Jul	31 2008	00000.255	
Multiplier	X	36000.0000	
31 days		**37008**	**kWh**

Meter Number: 898049

Aug	31 2008	00717.990	
Jul	31 2008	00717.990	
Multiplier	X	36000.0000	
31 days		**0**	**kWh**

Average current kWh/Day	1194
Average previous year kWh/Day	541

Meter Number: 898049

Aug	31 2008	00200.655	
Jul	31 2008	00199.579	
Multiplier	X	36000.0000	
31 days		**38736**	**kWh**

Meter Number: 9999998

Aug	31 2008	14.629	
Multiplier	X	1000.0000	
		14629	**kVA**

Payment return slip
Payable at most financial institutions

FORTISBC

Account Number
7609315215-5
Due Date
OCT-16-2008
Amount to be Withdrawn
$355,025.85
Amount Paid

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57033861730_1979.pdf.0001.2266

NELSON HYDRO
101310 WARD ST
NELSON BC V1L 5S4

7609315215 5 0035502585

Account Number: 7609315215-5 Continued Page 2/2

Other Charges and Adjustments

August City of Nelson NorthPoint = 3,364,000	123,618.95	
Reversed August City of Nelson NorthPoint	118,917.40CR	
	4,701.55	

Taxes

GST (5% on 4,701.55)	235.08	
	235.08	

Total New Charges	**4,936.63**
Amount to be Withdrawn	**$355,025.85**

Thank you — Your payment will be made by pre-authorized direct debit from your financial institution.

Nelson Hydro's GST registration number is 10698 4065 RT0001

Payment return slip
Payable at most financial institutions

Meter Reading Information

Meter Number: 898051

Aug 31 2008		00.3605	
Multiplier	X	36000.0000	
		12978	**kVA**

Aug 31 2008		00196.422	
Jul 31 2008		00121.681	
Multiplier	X	36000.0000	
31 days		**2690676**	**kWh**

Meter Number: 924185

Aug 31 2008		04744.642	
Jul 31 2008		04526.197	
Multiplier	X	4800.0000	
31 days		**1048536**	**kWh**

Average current kWh/Day	121869
Average previous year kWh/Day	126950

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FORTISBC

FortisBC Inc.
PO Box 8970, Station Main, Vancouver, BC V6B 4E2
Telephone: 1-866-4FORTIS (1-866-436-7847)
www.fortisbc.com

Account Name: NELSON HYDRO
Billing Date: OCT-08-2008
Billing Period: AUG-31-2008 to SEP-30-2008

7609315215-5
NOV-03-2008
Amount to be Withdrawn
$652,990.29

Previous statement	355,025.85	
Balance outstanding		**355,025.85**

Current Electric Charges

1 DAM SUBSTATION CR
(Meter 898051)
(Meter 898049)

0.00

1 DAM SUBSTATION
(Meter 898049)
(Meter 9999998)
(Meter 898051)
(Meter 924185)

Wholesale Rate	
Basic Customer Charge	3,667.74
Energy Used: 4,177,260 kWh @ $0.03507/kWh	146,496.51
Demand Charge Based on January	
Billed Demand 18,916.5 kVA @ $4.12/kVA	77,935.98
Interim Rate Increase	1,824.80
	229,925.03

Other Charges and Adjustments

September Metered export to FortisBC = 4,644	164.17CR
September City of Nelson NorthPoint = 1,528,000	54,014.80
	53,850.63

Taxes

GST (5% on 283,775.66)	14,188.78
	14,188.78

Total New Charges **297,964.44**

Meter Reading Information

Meter Number: 898051

Sep 30 2008	00001.412	
Aug 31 2008	00001.283	
Multiplier X	36000.0000	
30 days	**4644**	**kWh**

Meter Number: 898049

Sep 30 2008	00717.990	
Aug 31 2008	00717.990	
Multiplier X	36000.0000	
30 days	**0**	**kWh**

Average current kWh/Day	155
Average previous year kWh/Day	0

Meter Number: 898049

Sep 30 2008	00200.655	
Aug 31 2008	00200.655	
Multiplier X	36000.0000	
30 days	**0**	**kWh**

Meter Number: 9999998

Sep 30 2008	18.345	
Multiplier X	1000.0000	
	18345	**kVA**

Payment return slip
Payable at most financial institutions

FORTISBC

Account Number
7609315215-5
Due Date
NOV-03-2008
Amount to be Withdrawn
$652,990.29
Amount Paid

R1991.40592468084_1991.pdf0001

40592468084_1991.pdf.0001.2167

NELSON HYDRO
101310 WARD ST
NELSON BC V1L 5S4

7609315215 5 0065299029

Account Number: 7609315215-5 Continued Page 2/2

Amount to be Withdrawn	**$652,990.29**

Thank you — Your payment will be made by pre-authorized direct debit from your financial institution.

Nelson Hydro's GST registration number is 10698 4065 RT0001

Meter Reading Information

Meter Number: 898051

Sep 30 2008		00.2745	
Multiplier	X	36000.0000	
		9882	**kVA**

Sep 30 2008		00282.979	
Aug 31 2008		00196.422	
Multiplier	X	36000.0000	
30 days		**3116052**	**kWh**

Meter Number: 924185

Sep 30 2008		04965.727	
Aug 31 2008		04744.642	
Multiplier	X	4800.0000	
30 days		**1061208**	**kWh**

Average current kWh/Day	139242
Average previous year kWh/Day	0

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Payment return slip
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BCTC_NRPTRTNP94824_AESO

Tag Information			
GCA	PSE	Tag Code	LCA
BCTC	NRPTRT	NP94824	AESO

Start Date: **12/17/2008 06:00**

Stop Date: **12/17/2008 07:00**

Time Zone: **PS**
Transaction Type: **Normal**

Contact Information	
PSE Code	NRPTRT
PSE Contact	Corinne_Wilkinson
PSE Phone	(306)566-3309
PSE Fax	(306)566-3364
Gen Contact	Control Area Preschedule
Gen Phone	(604)473-2723
Gen Fax	(604)696-9886
Load Contact	System Controller
Load Phone	(403)233-7476
Load Fax	(403)261-7864
Comment	

WECC Reserve Sharing
BCTC (BA) 5%

Requests					
	Req	Type	Author	Time	Status
>>		Current Tag			
	0	Creation	NRPTRT (PSE)	12/17/2008 05:12	APPROVED

Market Path			
PSE	Product	Contract	Misc(Token/Value)
FBC001	G-F		
NRPTRT			
AESO	L		

Physical Path							
CA	TP	PSE	POR	POD	Sched Entities	Contract	Misc(Token/Value)
BCTC		FBC001	City of Nelson				
	BCTC	NRPTRT	KI	AB.BC	BCTC		
	AESO	AESO	AB.BC	AB.system	AESO		
AESO		AESO	AB.load				

Energy and Transmission Profiles MW (out of)											
			Gen	BCTC			AESO			Ramp Dur.	
Date	Start	Stop	MW	Trans	72740532	MW	Trans	INTERNAL	MW	Start	Stop
12/17/2008	06:00	07:00	5	5	5	5	5	5	5		
Display MWH Total:			5	5	5	5	5	5	5		
Original Tag MWH Total:			5								

Transmission Allocation			
TP	Owner	Product	OASIS
AESO	AESO	7-F	INTERNAL
BCTC	NRPTRT	2-NH	72740532

Loss Accounting					
TP	Start Time	Stop Time	Type	Contract Number	TagID
No loss accounting data exists for this tag.					

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BCTC_NRPTRTNP94744_PSEI

Tag Information			
GCA	PSE	Tag Code	LCA
BCTC	NRPTRT	NP94744	PSEI

Start Date: **12/15/2008 00:00**

Stop Date: **12/15/2008 06:00**

Time Zone: **PS**
Transaction Type: **Normal**

Contact Information	
PSE Code	NRPTRT
PSE Contact	Nicole_Sali
PSE Phone	(306)566-3309
PSE Fax	(306)566-3364
Gen Contact	Control Area Preschedule
Gen Phone	(604)473-2723
Gen Fax	(604)696-9886
Load Contact	Control Area Preschedule
Load Phone	(425)882-4630
Load Fax	(425)462-3049
Comment	Submitted by: RT-SDO

WECC Reserve Sharing
BCTC (BA) 5%

Requests					
	Req	Type	Author	Time	Status
>>		Current Tag			
	0	Creation	NRPTRT (PSE)	12/14/2008 22:52	APPROVED

Market Path			
PSE	Product	Contract	Misc(Token/Value)
FBC001	G-F		
NRPTRT			
PSEMKT			
PSEMKT	L		

Physical Path							
CA	TP	PSE	POR	POD	Sched Entities	Contract	Misc(Token/Value)
BCTC		FBC001	City of Nelson				
	BCTC	NRPTRT	KI	BC.US.Border	BCTC		
	PSEI	PSEMKT(1)	BC.US.BORDER	PSEI.SYSTEM	BPAT		
PSEI		PSEMKT(2)	PSEISYS				

Energy and Transmission Profiles
MW (out of)

			Gen	BCTC			PSEI			Ramp Dur.	
Date	Start	Stop	MW	Trans	72733340	MW	Trans	72733399	MW	Start	Stop
12/15/2008	00:00	01:00	6	6	6	6	6	6	6		
12/15/2008	01:00	02:00	7	7	7	7	7	7	7		
12/15/2008	02:00	03:00	8	8	8	8	8	8	8		
12/15/2008	03:00	06:00	7	7	7	7	7	7	7		
Display MWH Total:			42	42	42	42	42	42	42		
Original Tag MWH Total:			42								

Transmission Allocation			
TP	Owner	Product	OASIS
BCTC	NRPTRT	7-F	72733340
PSEI	PSEMKT	6-NN	72733399

Loss Accounting

1.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008

The FortisBC evidence at page 1 summarizes that (a) BC Hydro may not necessarily incur any material (opportunity cost) in connection with its provision of incremental energy under the PPA to replace energy exported by FortisBC's customers; and (b) BC Hydro may be able to earn a profit from its provision of any such incremental energy.

Q1.1 In the event that FortisBC's assumptions are incorrect and BC Hydro's assumptions are correct, does FortisBC believe that BC Hydro and its ratepayers should bear the risk of losses as forecasted by BC Hydro? If so, why?

A1.1 Yes. Please also refer to FortisBC's response to BCUC IR3 Q1.7.6.

Q1.2 In the event the Commission determines that BC Hydro's forecasts are reasonable and the best evidence, would FortisBC then accept that it would be appropriate in the interest of BC Hydro's ratepayers that the Commission approve the amendment to Section 2.1 of the PPA? If not, why not?

A1.2 No. Please refer to the response to CEC IR3 Q2.3 below.

Q1.3 Would FortisBC accept an amendment to the PPA which mitigates the risk to BC Hydro such that if their predictions prove accurate and there is a loss to BC Hydro which is to be made up by BC Hydro's ratepayers other than FortisBC and its customers and that loss can be demonstrated that the los should be made up by FortisBC and/or FortisBC's customers

who caused the loss? If not, please explain why BC Hydro and its ratepayers should bear this cost should it arise?

A1.3 Please refer to the response to CEC IR3 Q1.1.

2.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Determination of Loss or Profit)

> FortisBC has developed evidence to demonstrate, on the basis of assumptions different from those used by BC Hydro in the Application (and which are, in FortisBC's submission, more reasonable in the circumstances), that:
>
> (a) BC Hydro may not necessarily incur any material "opportunity cost" in connection with its provision of incremental energy under the PPA to replace energy exported by FortisBC customers; and
>
> (b) BC Hydro may be able to earn a profit from its provision of any such incremental energy.

(Exhibit C4-7, Page 1)

In challenging the BC Hydro estimate of its "opportunity costs" loss;

Q2.1 Does FortisBC agree that the potential for BC Hydro and its customers to incur a loss is relevant in this proceeding?

A2.1 Please also refer to the response to CEC IR3 Q2.3 below.

Q2.2 Does FortisBC propose that if BC Hydro and its customers are found to have incurred a profit that there is therefore no need to amend the PPA between BC Hydro and FortisBC?

A2.2 Please refer to the response to CEC IR3 Q2.3 below.

Q2.3 Does FortisBC agree that if BC Hydro and its customers are found to

have incurred a loss that this would constitute a base reason for having the PPA between BC Hydro and FortisBC amended?

A2.3 No. BC Hydro is obligated to deliver the contracted amount of power under the 3808 PPA in accordance with its terms and conditions. Please also refer to the responses to BC Hydro IR3 Q2.4 and Q8.1.

FortisBC believes the primary issue is whether self generators in FortisBC's service territory should be allowed to export power from their generation while taking embedded cost service. At present, all parties are operating within the terms and conditions of the existing contracts, agreements and tariffs. In FortisBC's opinion, those terms and conditions should not be altered in this application to the detriment of FortisBC's customers because BC Hydro and its customers may have incurred loss by complying with the terms of a contract that it negotiated with FortisBC. If this issue is to be considered, FortisBC submits that it should more appropriately be considered broadly as a matter of provincial government policy with a balanced review of the issue, and the production of a policy that best serves the interests of all parties. In any event, the parties' respective positions and the implementation of any government policy should only be considered during renewal negotiations and subsequent approval of the PPA, and not during the term of the contract.

3.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Cost of Energy to BC Hydro)

> (a) Cost to BC Hydro of replacement energy
>
> FortisBC does not believe that the long-term cost of new supply, used by BC Hydro to estimate its "opportunity cost" of providing replacement energy (see BC Hydro response to Commission IR 1.7.1.1), is a realistic proxy. FortisBC believes it is more appropriate to use the forecast cost of non-firm energy, since non-firm energy more closely resembles the energy BC Hydro might require to replace any energy exported by FortisBC customers. That is because non-firm energy is supplied without a capacity component. (BC Hydro has confirmed that City of Nelson exports do not change the magnitude of the capacity reservation held by BC Hydro on its system (see BC Hydro response to FortisBC IR 2.6.1).)
>
> In its 2008 Long Term Acquisition Plan (the "2008 LTAP"), BC Hydro has determined a "2008 Electricity Price Forecast" which it has used "to determine compensation for non-firm energy produced by successful bidders in the Clean Power Call" (see page 4-21 of the 2008 LTAP). A copy of Chapter 4 (Market Assessment) of the BC Hydro LTAP is attached as Attachment 1. Figure 4-6 on page 4-21 of the 2008 LTAP indicates that BC Hydro's own mid-range average hourly price forecast for the next several years is about $45/MWh.

(Exhibit C4-7, Page 2)

Q3.1 Does FortisBC agree that it has supplied replacement energy to enable the City of Nelson to enter into export transactions?

A3.1 FortisBC agrees that in hours when the City of Nelson is exporting its generation, FortisBC is supplying the full City of Nelson load.

Q3.2 Does FortisBC believe that the firmness or non-firmness of power in anyway affects its obligations under the FortisBC Power Purchase Agreement with BC Hydro to avoid exporting the purchased power?

A3.2 No. FortisBC does not export PPA power nor is FortisBC considering doing so.

Q3.3 Does FortisBC believe that the City of Nelson is restricted, in any way under FortisBC's Power Supply Agreement with the City of Nelson, from

establishing export transactions, which might require firm service?

A3.3 FortisBC is not clear on what the question is asking. The City of Nelson exports are firm, as is the power FortisBC supplies to the City of Nelson to meet the City of Nelson load.

Q3.4 Does FortisBC believe that the City of Nelson export transactions could occur in such a manner and at such times as to require capacity from BC Hydro?

A3.4 City of Nelson exports are generated at the City of Nelson generating station, not by BC Hydro. However, increased FortisBC load due to increased City of Nelson load may result in increased purchases of PPA power by FortisBC.

Q3.5 Does FortisBC acknowledge that BC Hydro has been a net purchaser of power from the electricity spot market for a number of years?

A3.5 Agreed.

Q3.6 Does FortisBC acknowledge that BC Hydro has an obligation to purchase power at the lowest cost available for its customers?

A3.6 FortisBC acknowledges that BC Hydro has an obligation to purchase power in a prudent and cost effective manner for its customers.

Q3.7 Does FortisBC acknowledge that BC Hydro has constraints and limitations on when it can buy power from the spot market particularly in the freshet season?

A3.7 Yes, in general. However, it is not clear what these limitations or constraints

are. FortisBC believes that it is clear from BC Hydro's continuing purchase patterns under the various calls for power that significant flexibility remains.

Q3.8 Does FortisBC acknowledge that the electricity spot markets are not infinite and that supply at a particular price is not necessarily available to everyone who may want supply at a particular time, because supply and demand in the market will affect the prices significantly?

A3.8 Agreed, however, FortisBC finds it difficult to accept that BC Hydro will find it impossible to replace any incremental energy that may be required on a non-firm basis at a significant discount to the rate stated by BC Hydro as the incremental cost. While the actual BC Hydro cost may be lower or higher depending on conditions that exist at the time, FortisBC believes its analysis is more reflective of the actual costs than BC Hydro's estimate.

Q3.9 Does FortisBC acknowledge that BC Hydro has multi-year storage capability and that it can and does purchase for its customers much of the low cost supply available from the electricity spot markets?

A3.9 While FortisBC agrees that BC Hydro is an active buyer, the percentage of the market that BC Hydro is buying is difficult to estimate. FortisBC certainly believes that a significant market potential remains.

Q3.10 Does FortisBC acknowledge that BC Hydro subsidiary Powerex trades electricity on the electricity spot markets generating a benefit for BC Hydro customers in the form of trade income, and that this may involve Powerex buying low cost power from the electricity spot markets and reselling it to the electricity spot markets at a later date and potentially at higher prices than it aid for the power?

A3.10 Agreed.

Q3.11 Does FortisBC acknowledge that the electricity price forecasts it references in the BC Hydro 2008 LTAP may not be actual prices available to a buyer at some point in the future?

A3.11 FortisBC agrees that the actual price may be higher or lower than any forecast of prices.

Q3.12 Does FortisBC acknowledge that the electricity spot market prices it suggests are the BC Hydro marginal cost are available to FortisBC and to the City of Nelson as well?

A3.12 Agreed, however, please also refer to the response to BCUC IR3 Q1.7.1.

Q3.13 Would FortisBC agree to avoid taking power from BC Hydro to enable the City of Nelson export transactions and instead supply all of the power itself from its own purchases from the electricity spot markets and if not why not?

A3.13 No. Please refer to the responses to BC Hydro IR3 Q1.2 and CEC IR3 Q2.3. FortisBC and the City of Nelson entered into the required agreements based on the premise that existing contracts and tariffs were in effect and with the knowledge that these transactions were in accordance with those contracts and tariffs. If there was a restriction such as that proposed in the question, there may have been a different outcome to these contract negotiations.

Q3.14 Would FortisBC agree that whenever it is supplying power to the City of Nelson to enable the City of Nelson export transactions it would take the

power from BC Hydro at the electricity spot market prices and not under RS3808 and if not why not?

A3.14 No. Please see the response to CEC IR3 Q3.13 above.

Q3.15 What does FortisBC understand to be the difference in quality and nature between the supply the City of Nelson is planning on using to support its export transactions, and obtaining from FortisBC and BC Hydro, versus the electricity spot market supply FortisBC is proposing would be BC Hydro's marginal source of supply?

A3.15 As explained in the response to BCOAPO IR3 Q3.1a, BC Hydro can make up any required energy as non-firm power since no additional capacity must be allocated to the PPA. The full amount of the PPA capacity is continuously held on the BC Hydro system, and in FortisBC's view, cannot do double duty by being allocated to any other use. Since any incremental PPA capacity that may be supplied to FortisBC due to increased FortisBC load (for whatever reason) is already reserved and available at any time, increased FortisBC load under the PPA does not require BC Hydro to set aside any additional capacity, just to utilize that capacity which has already been set aside for that express purpose.

Q3.16 Does FortisBC believe that the City of Nelson would purchase supply from the electricity spot markets to support its export transactions and if not why not?

A3.16 If the City of Nelson must purchase on the spot market for the same hour as any export transaction it may enter into FortisBC believes the volume of transactions the City of Nelson would engage in would significantly decrease since transactions that must occur for the same hour would not allow a profit in

most cases. However, since BC Hydro need not replace any incremental energy it may require on the same hour as the export, this logic does not apply to BC Hydro.

4.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Price of Power Purchase by Fortis from BC Hydro)

> (b) Price of power sold to FortisBC under the PPA
>
> Attached as Attachment 2 is a document showing that FortisBC's forecast of the combined cost of its energy and capacity purchases from BC Hydro under the PPA would be approximately $39.6/MWh (before taking into account any rate increase for 2008 or 2009).

(Exhibit C4-7, Page 2)

Q4.1 In the first part of the FortisBC evidence the proposition is made that the comparable energy is non-firm energy, so why does FortisBC include capacity values in the price of power purchased by FortisBC from BC Hydro under the PPA?

A4.1 Please refer to the response to BC Hydro IR3 Q5.9.

Q4.2 BC Hydro has argued that there is a capacity affect of the proposed export transactions of FortisBC customers, so is FortisBC in effect endorsing the BC Hydro position when it adopts the combined energy and capacity values in its calculation of the price of power?

A4.2 No, please refer to the response to BC Hydro IR3 Q5.9.

5.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Adjustments)

(d) Application of further adjustments

(i) market trading efficiency factor

FortisBC believes that by making prudent buying decisions, BC Hydro could replace any requisite incremental energy at pries equivalent to, if not better than, the embedded cost price at which it would be selling energy to FortisBC under the PPA.

First, it should be noted that the $45/MWh figure is an average amount. Actual prices will, obviously, vary from the average. Moreover, BC Hydro is generally regarded as one of the most skilled and accomplished energy traders in North America. Accordingly, FortisBC believes that BC Hydro can reasonably be expected to achieve at least a 10% efficiency advantage over the average price.

(ii) anticipated rate increase

FortisBC believes it is reasonable to anticipate about a 7% cumulative rate increase for power deliveries under the PPA in 2008 and 2009.

(Exhibit C4-7, Page 2 & 3)

Q5.1 Does FortisBC believe that it could make prudent buying decision to replace, from the spot electricity market, the requisite incremental energy at prices equivalent to, if not better than, the embedded cost price at which it buys energy from BC Hydro under the PPA, if not why not?

A5.1 Please refer to the response to BCUC IR3 Q1.7.1.

Q5.2 Does FortisBC accept that BC Hydro may already be taking and or planning to take the energy from the electricity spot market when it is available at prices below the average $45 MWh and for an additional marginal purchase the only energy available may be at higher prices than the average, if not why not?

A5.2 FortisBC agrees that the actual price paid by BC Hydro may be higher than the

$45 MWh, however, it could also be lower.

Q5.3 Does FortisBC have any evidence that BC Hydro and or Powerex are consistently day in and day out throughout the year not already taking or planning to take energy from the spot electricity market when the price is below $45 MWh?

A5.3 FortisBC considers this one of the key questions in determining the actual impact on BC Hydro. Based on market experience, and observations in the hourly markets, FortisBC believes that significant opportunity exists for BC Hydro to replace the energy at a rate significantly below the cost BC Hydro has currently stated as the replacement cost. The $45 estimate FortisBC used is BC Hydro's own estimate of the market for the next several years. BC Hydro was asked to provide additional market based evidence in BCOAPO IR2 Q2.3.3 (Exhibit B-9) and declined to do so. If BC Hydro chooses to provide detailed and credible information that indicates BC Hydro's incremental cost for non-firm power is higher than $45 per MWh, then FortisBC will review that information. However, BC Hydro has expressly chosen not to provide such information. Therefore, until such time as BC Hydro performs the required detailed analysis, it is reasonable to rely on BC Hydro's own previous estimate of market costs.

Q5.4 Does FortisBC have any evidence that there is a consistent and regular daily availability throughout the year of spot electricity market energy at prices below $45 MWh?

A5.4 No. However FortisBC believes that because there is no capacity impact resulting from the Nelson exports (please refer to the response to CEC IR3 Q6.1 below), consistent and regular daily availability of capacity at rates below

$45 per MWh is not required, because the energy can be replaced as non-firm power over a much wider time period.

Q5.5 In anticipating price increases for energy FortisBC refers to 2008 and 2009, are these calendar years or BC Hydro fiscal years?

A5.5 These are BC Hydro fiscal years.

Q5.6 What is the basis for anticipating BC Hydro rate increases of 7%?

A5.6 Once the final BC Hydro rate increase is known, the combined rate increase over both years of 7 percent should be replaced with the actual rate increase. FortisBC does not claim any “inside” information as to what the final BC Hydro rate increase will be. However, for the purposes of this evidence, a rate had to be assumed and 7 percent did not seem unreasonable.

Q5.7 As BC Hydro has forecast some significant price increases over the next several years in its LTAP forecasts but the forecast average price in its market assessment is below $50 MWh until about 2019, would FortisBC forego its ability to make purchases under the PPA when and if the BC Hydro price crosses over and becomes higher than the average spot electricity market price?

A5.7 No. The 3808 contract is in place until 2013 and FortisBC intends to comply with its contractual obligations through the full 20 year term. Also, please refer to the response to BCUC IR3 Q5.2.

6.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Provision of Operating Information)

> *Provision of operating information*
>
> FortisBC is prepared to work with BC Hydro to ensure that BC Hydro is not inadvertently reserving more capacity on the BC Hydro system than is necessary to meet its obligations under the PPA.

(Exhibit C4-7, Page 3)

Q6.1 Does FortisBC have any evidence that BC Hydro is inadvertently reserving more capacity on the BC Hydro system than is necessary to meet its obligations under the PPA?

A6.1 No. FortisBC believes that if BC Hydro is planning to be able to meet the terms of the PPA at all times, there is no capacity impact from the City of Nelson exports. If BC Hydro is not planning to meet the terms of the PPA at all times, it may believe there is a capacity impact. However, since BC Hydro has confirmed (please refer to the response to BCOAPO IR3 Q3.1 for an explanation of this) that it does hold the maximum amount of PPA capacity available to FortisBC on the system at all times, it is clearly planning to meet the PPA obligations.

The other possible explanation is that too much capacity is being held on the system due to technical errors on the part of BC Hydro in accounting for PPA capacity requirements when the City of Nelson is exporting. FortisBC believes the PPA technical committee should resolve this issue and is committed to work with BC Hydro to ensure correct PPA operations.

Q6.2 Does FortisBC believe there is a possibility that BC Hydro is inadvertently reserving more capacity on the BC Hydro system than is necessary to

meet its obligations under the PPA, and if so why?

A6.2 Please refer to the response to CEC IR3 Q6.1 above.

Q6.3 Does FortisBC have an estimate of how much capacity BC Hydro may be unnecessarily reserving on the BC Hydro system?

A6.3 Please refer to the response to CEC IR3 Q6.1 above.

7.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (PPA prohibition on Export)

> Section 2.2 states:
>
> "Export" and all forms of the verb "to Export" means, for the purposes of this Agreement, any transaction by or on behalf of West Kootenay Power whereby Electricity leaves the West Kootenay Power service area save and except for the following:
>
> (a) Wheeling losses scheduled to B.C. Hydro;
>
> (b) Emergency exchanges as defined by the Northwest Power Pool;
>
> (c) Capacity Purchases by West Kootenay Power; and
>
> (d) Such exceptions as the parties may agree to provided that any dispute in this regard shall be referred to the Commission or such person as the Commission may designate from time to time."
>
> While BC Hydro acknowledges that nothing in the PPA directly prohibits FortisBC customers such as the City of Nelson from exporting their own power, BC Hydro's view is that the spirit and intent of the PPA is that PPA power cannot be used to replace power exported by FortisBC customers.

(Exhibit B-5, BCUC 1.4.2)

Q7.1 Does FortisBC agree that the energy it purchased from BC Hydro to supply to the City of Nelson to enable its May and June 2008 export transactions was not:

i. For wheeling losses scheduled to BC Hydro;

ii. For emergency exchanges as defined by the Northwest Power Pool;

iii. For Capacity Purchases by FortisBC; and

iv. For any exception agreed to by ForisBC and BC Hydro?

A7.1 Agreed, the energy FortisBC purchased from BC Hydro was to meet City of Nelson load, and not for any of the four reasons listed above.

Q7.2 Does FortisBC agree that the energy it purchased from BC Hydro to supply the City of Nelson to enable its May and June 2008 export transactions left the FortisBC service area?

A7.2 No, all energy FortisBC purchased from BC Hydro was used to meet FortisBC load. It was the energy generated at the City of Nelson plant that left the service area. The PPA is clear that FortisBC cannot store PPA energy, but can store entitlement energy while PPA energy is being taken (Section 2.1 of the PPA). In other words, just because an export is taking place at the same time PPA power is being taken, it does not follow that the PPA power is being exported.

Q7.3 Does FortisBC agree that, if the energy it purchased from BC Hydro to supply the City of Nelson to enable its May and June 2008 export transactions had not been supplied by BC Hydro, the City of Nelson export transaction could not have proceeded?

A7.3 FortisBC agrees that, for the portion of the May and June 2008 export transactions that FortisBC met the incremental City of Nelson load with PPA power. If no additional power under the PPA had been available to FortisBC,

then it is possible that FortisBC would have declined to allow the export to take place. This would have been done in accordance with the negotiated terms of the Power Coordination Agreement, in particular Article 2.8, titled FortisBC Election.

Q7.4 Does FortisBC agree that, if the energy it purchased from BC Hydro to supply the City of Nelson to enable its May and June 2008 export transactions had not been supplied by BC Hydro, the City of Nelson export transaction could only have proceeded if FortisBC had found another source of supply for the City of Nelson?

A7.4 Agreed for the portion of the increased FortisBC load that was met with BC Hydro power.

8.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Wheeling & Ancillary Services)

> In order to deliver energy to Northpoint and export energy out of the FortisBC service territory, the City of Nelson is required to deliver the power to the Kootenay Interconnection. Under the Umbrella Agreement between FortisBC and the City of Nelson, the energy is wheeled over FortisBC's transmission system using FortisBC's WTS tariff. The City of Nelson will also need to purchase ancillary services in order to facilitate the transmission of energy to the Kootenay Interconnection. It is unclear to BC Hydro as to whether or not the appropriate ancillary services have been supplied and by whom.

(Exhibit B-5, BCUC 1.5.1)

Q8.1 Has FortisBC supplied the wheeling over the FortisBC transmission system under the FortisBC WTS tariff to enable to City of Nelson export transactions?

A8.1 Yes.

Q8.2 Has FortisBC supplied the City of Nelson or Northpoint with any ancillary services to enable the City of Nelson export transactions?

A8.2 Yes.

Q8.3 Does FortisBC agree that all other tings being equal the energy purchased by FortisBC from BC Hydro has been subsequently routed over FortisBC transmission lines for export leaving the FortisBC service area?

A8.3 No, please refer to the response to CEC IR3 Q7.2 above.

9.0 Reference: Intervenor Evidence filed by FortisBC on December 15, 2008 (Arbitrage of Embedded Cost Power)

> The primary principle of the BCUC Orders is that BC Hydro customers are not to arbitrage between embedded cost utility service and market prices. FortisBC is a customer of BC Hydro in-so-far as it purchases energy from BC Hydro under the PPA, and the PPA itself prevents arbitrage with its provision that FortisBC is not permitted to export energy out of its service territory when it is purchasing energy under the PPA.

(Exhibit B-5, BCUC 1.10.3)

Q9.1 Does FortisBC believe that its customers in principle should be permitted to arbitrage between the embedded cost of BC Hydro utility service and market prices?

A9.1 Note that FortisBC customers receive embedded cost, bundled service from FortisBC. Because rates to FortisBC customers reflect FortisBC's overall cost of service, of which the BC Hydro PPA is a part, this question is not applicable.

Q9.2 Does FortisBC believe that its customers in principle should be permitted

to arbitrage between the embedded cost of FortisBC utility service and market prices?

A9.2 FortisBC ensures that the power sold to its customers is used to serve native load. This is a specific contractual requirement of the Power Coordination Agreement with the City of Nelson.

The question in this application is whether a FortisBC customer with self generation is free to export its self generation while serving its load with purchased power under existing tariffs. Please also refer to the responses to BC Hydro IR3 Q1.3 and CEC IR3 Q2.3.

1.0 Reference: Exhibit C4-7, page 3
Exhibit B-1, page 4

Preamble: A key concern underlying BC Hydro's Application appears to be that it will incur a loss if required to provide incremental energy to FortisBC (for the purpose of supporting export activities of FortisBC's customers).

Q1.1 Does FortisBC agree that this is a legitimate concern?

A1.1 Please refer to the response to CEC IR3 Q2.3 and Q5.3.

Q1.2 Please confirm that it is FortisBC's position that BC Hydro will not incur a financial loss if required to provide energy to FortisBC for purposes of supporting export activities of FortisBC's customers.

A1.2 Given the assumptions provided in FortisBC's evidence, the majority of which is based on the BC Hydro 2008 LTAP, BC Hydro would not incur a material financial loss. Of course, the actual price BC Hydro will have to pay to replace any required power may be higher or lower than any estimate based on a forecast of prices. Please also refer to the response to CEC IR3 Q5.3

Q1.3 If the facts were such that BC Hydro would incur a financial loss, what are FortisBC's views as to whether or not the associated sales to FortisBC should be permitted to take place?

A1.3 Please see the responses to BCUC IR3 Q1.7.6 and CEC IR3 Q2.3. Both FortisBC and BC Hydro agree that these transactions fall within established tariffs and contracts and are taking place as per the associated commercial

terms and conditions. In other words, BC Hydro and FortisBC are obligated to honour the terms of the 3808 PPA and Electric Tariffs and these terms should not be amended as requested by BC Hydro.

2.0 Exhibit C4-7, Attachment 2

Q2.1 Please confirm that Attachment 2 reflects FortisBC's 2009 forecast purchase power expense assuming the incremental sales to the City of Nelson and Zellstoff Celgar (to support their "export sales").

A2.1 Not confirmed. Attachment 2 in Exhibit C4-7 includes 25 GWh of incremental City of Nelson load due to its exports and no incremental load for Zellstoff Celgar.

Q2.2 If yes, please provide a revised version of Attachment 2, assuming no "export sales" by the City of Nelson and Zellstoff Celgar.

A2.2 Please refer to BCOAPO Appendix A2.2. The 2009 load forecast has been reduced by 25 GWh, 2.5 GWh each month except May and June. There is no change to the capacity forecast.

Q2.3 If no, please provide a revised version of Attachment 2, assuming incremental "export sales" by the City of Nelson and Zellstoff Celgar.

A2.3 Please refer to BCOAPO Appendix A2.3. The 2009 load forecast has been increased by 350 GWh spread evenly across the year and by 40 MW in every month.

Q2.4 For each month in 2009 please breakdown the total sales to the City of Nelson and Zellstoff Celgar (made in support of "exports") as between

Heavy Load and Light Load Hours (as defined in the PPA – BCUC IR 1.4.1, Attachment 1).

A2.4 FortisBC does not develop the load forecast in this manner since energy and capacity are planned for separately. It is difficult to estimate the breakdown of the City of Nelson deliveries, however, it is fully expected that the City of Nelson will not be exporting during extreme peak periods. Zellstoff Celgar is expected to become a full service customer of approximately 40 MW with a constant load totalling about 350 GWh annually. The PPA defines the Heavy Load Hours as 16 hours a day, seven days a week or 66.67 percent of the hours in the year. Therefore, approximately 233 GWh of the Celgar energy will be on the Heavy Load Hours as defined in the PPA. Note that the standard market definition of Heavy Load power comprises about 55 percent of the hours in a year as the definition excludes all day Sunday and major holidays such as Christmas.

3.0 Exhibit C4-7, page 2

Q3.1 In determining BC Hydro's cost of replacement energy, FortisBC assumes a price equivalent to that for non-firm energy on the basis that exports by FortisBC's customers will not change the magnitude of the capacity reservation held by BC Hydro. This assumes that BC Hydro bases its firm supply obligations on the "capacity reservation" it has for FortisBC.

Q3.1a Does this same view hold if BC Hydro bases its firm supply obligations on a "forecast" of FortisBC's anticipated supply requirements?

A3.1a No, it does not. However, in FortisBC's opinion, for BC Hydro to

remain able to be compliant with the PPA at all times, BC Hydro must base its hourly operations on the "capacity reservation" rather than the "forecast" of use. BC Hydro has acknowledged this principle of the PPA agreement in its response to FortisBC IR2 Q2.6.1 (Exhibit B-9) where BC Hydro confirmed that, "Nelson exports do not change the magnitude of the capacity reservation held by BC Hydro on its system in any way, since this obligation is related to the 5-year nomination only and must be held on the BC Hydro system continuously, regardless of anticipated use, since it is an on-demand obligation."

Therefore, since the maximum possible use of the PPA is continuously held on the BC Hydro system, the actual use of the PPA capacity does not increase the amount of capacity BC Hydro must allocate to the PPA. While this does not establish the replacement value of energy that BC Hydro will incur, it does mean that it is non-firm energy rather than firm.

Given that replacement energy can be non-firm, FortisBC believes BC Hydro has significant flexibility in the timing of acquiring replacement energy and therefore should be able to replace it at rates that are equal to or below average market rates.

Q3.1b **If BC Hydro bases its firm supply obligations on a forecast of anticipated sales to FortisBC (up to the limits specified in the PPA), what – in FortisBC's view – is the appropriate reference price to use for replacement energy?**

A3.1b BC Hydro has already confirmed that under the PPA it must base its firm supply obligations on the "capacity reservation", not the forecast.

Please refer to the response to CEC Q3.1a above.

1		2009			ANALYSIS OF FORECAST POWER PURCHASE EXPENSE									
2					FOR THE YEAR ENDING DECEMBER 31,				2009					23-Dec
3		2	3	4	5	6	7	8	9	10	11	12	13	
4		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
5	**ENERGY GW.h**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
6	FortisBC	156	151	140	119	128	128	136	118	123	111	118	152	1580.649
7	Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857.415
8	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	65.093
9	Brilliant Regulated	0	0	0	0	0	0	0	0	0	0	0	0	0.000
10	Cominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000
11	Small Misc IPP Resource	1	0	1	1	3	2	3	1	1	1	1	1	13.000
12														
13	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
14		0	0	0	0	0	0	0	0	0	0	0	0	0.000
15	CPC Loss, Wheeling & PPA Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0.000
16	DSM	2	2	2	2	2	2	2	2	2	2	2	2	25.192
17	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0.000
18	Market Capacity - ENERGY	1	0	4	0	0	0	3	0	0	0	0	0	7.823
19	Market Energy Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0.000
20	BCH Purchase	123	106	105	54	30	30	42	30	54	84	112	116	885.379
21		----	----	----	----	----	----	----	----	----	----	----	----	----
22	Gross Load	366	322	309	267	256	242	250	249	246	261	297	337	3401.113
23	Surplus	0	0	0	0	0	4	29	0	0	0	0	0	33.438
24	**RATE (Mills/kW.h)**												Pwr Pur =	1828.710
25	Surplus Rate	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
26	Brilliant Base Plant	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
27	Brilliant Upgrade	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	
28	Brilliant Regulated	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	
29														
30	Market Capacity - ENERGY	80.32	74.49	61.69	56.30	45.65	47.77	94.80	115.57	84.12	73.68	84.44	100.38	
31	Market Energy Purchase	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
32	BCH : Purchase	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	
33	IPP Rate	28.254	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	
34	**ENERGY EXPENSE ($000)**													
35	Surplus Revenue	$0	$0	$0	$0	$0	($76)	($977)	$0	$0	$0	$0	$0	-1052.967
36	Brilliant Base Plant	$2,789	$2,146	$2,007	$2,785	$2,699	$2,459	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	29244.667
37	Brilliant Upgrade	$18	($17)	($11)	$254	$360	$335	$360	$330	$25	$16	$8	$9	1685.909
38	Brilliant Regulated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
39		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
40														
41	IPP Costs	$14	$11	$20	$17	$71	$62	$76	$17	$20	$14	$23	$23	367.302
42	BCH Purchase	$3,477	$2,985	$2,958	$1,518	$859	$836	$1,196	$836	$1,523	$2,366	$3,176	$3,284	25015.501
43	Market Capacity - ENERGY	$55	$0	$251	$0	$0	$0	$283	$1	$0	$0	$6	$0	596.283
44	Market Energy Purchase	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
45		----	----	----	----	----	----	----	----	----	----	----	----	----
46		$6,353	$5,126	$5,225	$4,573	$3,989	$3,616	$3,639	$4,115	$3,818	$4,516	$5,356	$5,531	55856.695
47														

		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
48	**CAPACITY (MW)**													
49	FortisBC	202	199	181	183	187	178	188	203	200	194	193	208	2316.639
50	Brilliant Base Plant	123	123	87	117	106	100	106	115	119	119	123	123	1359.238
51	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238.000
52	Brilliant Tailrace Capacity	4	3	1	3	6	6	6	4	1	1	3	5	42.200
53	Cominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000
54	Market Capacity	7	0	67	0	0	0	48	5	0	0	4	0	131.047
55		0	0	0	0	0	0	0	0	0	0	0	0	0.000
56	FortisBC DSM	5	4	4	4	4	3	3	3	4	4	4	5	45.400
57		0	0	0	0	0	0	0	0	0	0	0	0	0.000
58	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
59	Cominco Market Capacity	150	75	0	0	0	0	0	0	0	0	75	125	425.000
60	CPC Market Capacity	0	0	0	0	0	0	0	0	0	0	0	25	25.000
61	BCH : Billing Capacity	190	176	190	165	143	188	190	190	143	182	190	164	2110.257
62	BCH : Used for Load	190	176	190	165	134	188	190	190	111	182	190	164	2070.011
63	BCH : Excess Purch	0	0	0	0	0	0	0	0	0	0	0	0	0.000
64		----	----	----	----	----	----	----	----	----	----	----	----	----
65	Gross FortisBC Monthly Peak	701	600	551	492	455	495	560	539	454	519	613	666	6643.700
66														
67	Capacity Planning Load	701	600	551	492	455	495	560	539	454	519	613	666	6643.700
68	**RATE ($/MW-month) / EXPENSE ($000)**													
69	BCH 3808 Rate	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	
70	BCH 3808 Capacity Charge	$916	$847	$916	$796	$687	$907	$916	$916	$687	$877	$916	$793	10172.536
71	BRD Tailrace Capacity Charge	$16	$11	$4	$9	$22	$22	$21	$13	$3	$3	$12	$17	152.569
72														0.000
73	Cominco Capacity Charge	$1,001	$506	$0	$0	$0	$0	$0	$0	$0	$0	$423	$705	2635.513
74	CPC Capacity Charge												$195	195.000
75	Total Capacity EXPENSE($000)	$1,933	$1,363	$920	$805	$709	$929	$937	$929	$690	$880	$1,351	$1,711	13155.618
76														
77	**TOTAL POWER PURCH EXPENSE($000)**													
78	Surplus Revenues	$0	$0	$0	$0	$0	($76)	($977)	$0	$0	$0	$0	$0	-1052.967
79	Export Wheeling Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
80	Brilliant	$2,823	$2,141	$1,999	$3,047	$3,081	$2,816	$3,081	$3,274	$2,279	$2,139	$2,164	$2,241	31083.146
81														
82	BCH	$4,393	$3,831	$3,874	$2,313	$1,546	$1,743	$2,112	$1,752	$2,210	$3,243	$4,092	$4,077	35188.037
83	BCH Excess/Unallocated Costs	$0	$0	$1	$4	$11	$25	$43	$7	$5	$0	$0	$0	96.996
84	Call Option	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
85	Market Spot Purchase & Com Capacity	$1,056	$506	$251	$0	$0	$0	$283	$1	$0	$0	$429	$900	3426.796
86	IPP	$14	$11	$20	$17	$71	$62	$76	$17	$20	$14	$23	$23	367.302
87														
88	Capital Projects	($43)		($65)								($75)	($26)	-208.431
89	Special & Accounting Adjustments													0.000
90	Balancing Pool Adjustments	$226	$769	$661	($520)	($226)	$57	($20)	($848)	($283)	($424)	($158)	$576	-189.217
91		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
92	**TOTAL**	$8,469	$7,258	$6,741	$4,862	$4,483	$4,627	$4,599	$4,204	$4,231	$4,972	$6,475	$7,792	$68,711.661

1		2009			ANALYSIS OF FORECAST POWER PURCHASE EXPENSE									
2					FOR THE YEAR ENDING DECEMBER 31,				2009					23-Dec
3		2	3	4	5	6	7	8	9	10	11	12	13	
4		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
5	**ENERGY GW.h**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
6	FortisBC	156	151	140	119	140	128	124	118	123	111	118	152	1580.649
7	Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857.415
8	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	65.093
9	Brilliant Regulated	0	0	0	0	0	0	0	0	0	0	0	0	0.000
10	Cominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000
11	Small Misc IPP Resource	1	0	1	1	3	2	3	1	1	1	1	1	13.000
12														
13	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
14		0	0	0	0	0	0	0	0	0	0	0	0	0.000
15	CPC Loss, Wheeling & PPA Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0.000
16	DSM	2	2	2	2	2	2	2	2	2	2	2	2	25.192
17	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0.000
18	Market Capacity - ENERGY	5	1	10	0	0	1	8	1	0	0	1	0	27.315
19	Market Energy Purchase	16	13	4	0	0	0	0	0	0	0	8	10	51.785
20	BCH Purchase	134	121	127	85	48	53	52	61	85	116	134	139	1155.664
21		----	----	----	----	----	----	----	----	----	----	----	----	----
22	Gross Load	398	351	341	298	286	271	282	281	278	293	328	370	3776.113
23	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0.000
24	**RATE (Mills/kW.h)**												Pwr Pur =	2170.272
25	Surplus Rate	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
26	Brilliant Base Plant	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
27	Brilliant Upgrade	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	
28	Brilliant Regulated	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	
29														
30	Market Capacity - ENERGY	80.32	74.49	61.69	56.30	45.65	47.77	94.80	115.57	84.12	73.68	84.44	100.38	
31	Market Energy Purchase	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
32	BCH : Purchase	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	
33	IPP Rate	28.254	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	
34	**ENERGY EXPENSE ($000)**													
35	Surplus Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
36	Brilliant Base Plant	$2,789	$2,146	$2,007	$2,785	$2,699	$2,459	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	29244.667
37	Brilliant Upgrade	$18	($17)	($11)	$254	$360	$335	$360	$330	$25	$16	$8	$9	1685.909
38	Brilliant Regulated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
39		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
40														
41	IPP Costs	$14	$11	$20	$17	$71	$62	$76	$17	$20	$14	$23	$23	367.302
42	BCH Purchase	$3,794	$3,427	$3,595	$2,399	$1,360	$1,506	$1,480	$1,719	$2,406	$3,264	$3,788	$3,914	32652.137
43	Market Capacity - ENERGY	$417	$47	$615	$4	$0	$34	$767	$115	$0	$33	$101	$0	2133.397
44	Market Energy Purchase	$958	$702	$183	$0	$0	$0	$0	$0	$0	$0	$519	$726	3086.397
45		----	----	----	----	----	----	----	----	----	----	----	----	----
46		$7,989	$6,317	$6,408	$5,458	$4,490	$4,396	$5,383	$5,112	$4,701	$5,447	$6,582	$6,886	69169.809

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
CAPACITY (MW)													
FortisBC	202	199	181	183	187	178	188	203	200	194	193	208	2316.639
Brilliant Base Plant	123	123	87	117	106	100	106	115	119	119	123	123	1359.238
Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238.000
Brilliant Tailrace Capacity	4	3	1	3	6	6	6	4	1	1	3	5	42.200
Cominco	0	0	0	0	0	0	0	0	0	0	0	0	0.000
Market Capacity	47	26	107	15	0	38	88	45	0	32	38	0	435.841
	0	0	0	0	0	0	0	0	0	0	0	0	0.000
FortisBC DSM	5	4	4	4	4	3	3	3	4	4	4	5	45.400
	0	0	0	0	0	0	0	0	0	0	0	0	0.000
Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
Cominco Market Capacity	150	75	0	0	0	0	0	0	0	0	75	125	425.000
CPC Market Capacity	0	0	0	0	0	0	0	0	0	0	0	25	25.000
BCH : Billing Capacity	190	190	190	190	174	190	190	190	151	190	196	196	2236.754
BCH : Used for Load	190	190	190	190	174	190	190	190	151	190	196	196	2236.754
BCH : Excess Purch	0	0	0	0	0	0	0	0	0	0	0	0	0.000
	---	---	---	---	---	---	---	---	---	---	---	---	---
Gross FortisBC Monthly Peak	741	640	591	532	495	535	600	579	494	559	653	706	7123.700
Capacity Planning Load	741	640	591	532	495	535	600	579	494	559	653	706	7123.700
RATE ($/MW-month) / EXPENSE ($000)													
BCH 3808 Rate	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	4820.52	
BCH 3808 Capacity Charge	$916	$916	$916	$916	$836	$916	$916	$916	$729	$916	$945	$945	10782.317
BRD Tailrace Capacity Charge	$16	$11	$4	$9	$22	$22	$21	$13	$3	$3	$12	$17	152.569
													0.000
Cominco Capacity Charge	$1,001	$506	$0	$0	$0	$0	$0	$0	$0	$0	$423	$705	2635.513
CPC Capacity Charge												$195	195.000
Total Capacity EXPENSE($000)	$1,933	$1,433	$920	$925	$858	$938	$937	$929	$732	$919	$1,380	$1,863	13765.399
TOTAL POWER PURCH EXPENSE($000)													
Surplus Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
Export Wheeling Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
Brilliant	$2,823	$2,141	$1,999	$3,047	$3,081	$2,816	$3,081	$3,274	$2,279	$2,139	$2,164	$2,241	31083.146
BCH	$4,710	$4,343	$4,510	$3,315	$2,197	$2,421	$2,396	$2,635	$3,135	$4,180	$4,733	$4,859	43434.455
BCH Excess/Unallocated Costs	$0	$0	$1	$4	$11	$25	$43	$7	$5	$0	$0	$0	96.996
Call Option	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
Market Spot Purchase & Com Capacity	$2,375	$1,255	$798	$4	$0	$34	$767	$115	$0	$33	$1,043	$1,626	8050.306
IPP	$14	$11	$20	$17	$71	$62	$76	$17	$20	$14	$23	$23	367.302
Capital Projects	($43)		($65)								($75)	($26)	-208.431
Special & Accounting Adjustments													0.000
Balancing Pool Adjustments	$226	$769	$661	($520)	$113	$57	($359)	($848)	($283)	($424)	($158)	$576	-189.217
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL	$10,105	$8,518	$7,925	$5,867	$5,472	$5,415	$6,004	$5,201	$5,156	$5,942	$7,729	$9,299	$82,634.557

FARRIS

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Reply Attention of: Dean O'Leary
Direct Dial Number: (604) 661-9316
Email Address: doleary@farris.com

Our File No.: 5497-163-2

January 23, 2009

BY E-MAIL AND COURIER

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, B.C. V6Z 2N3

Attention: Erica Hamilton
Commission Secretary

Dear Sirs/Mesdames:

Re: An Application by British Columbia Hydro and Power Authority to Amend Section 2.1 of Rate Schedule 3808 ("RS 3808") Power Purchase Agreement – Project No. 3698531

We are transmitting with this letter, for filing with you, FortisBC's Final Argument in connection with the above-noted matter. The original will follow by courier.

Yours truly,

FARRIS, VAUGHAN, WILLS & MURPHY LLP

Per:

Dean O'Leary

DOL/fc
Encl.
c.c.: FortisBC Inc.

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

- and -

An Application by British Columbia Hydro and Power Authority
to Amend Section 2.1 of Rate Schedule 3808 ("RS 3808")
Power Purchase Agreement

To: British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, British Columbia
V6Z 2N3

FINAL SUBMISSION OF FORTISBC INC.

I. THE APPLICATION

1. British Columbia Hydro and Power Authority ("**BC Hydro**") has made application (the "**Application**") to the British Columbia Utilities Commission (the "**Commission**") pursuant to Section 58(1) and (2) of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473, as amended (the "**Act**") for approval to amend Section 2.1 of the Power Purchase Agreement made as of the 1st day of October, 1993 between BC Hydro and FortisBC Inc. (then known as West Kootenay Power Ltd.), as amended, (the "**Power Purchase Agreement**"). The Power Purchase Agreement is filed in these proceedings as Exhibit B-5, Attachment 1 to BC Hydro response to Commission IR 1.4.1.

2. Section 2.1 of the Power Purchase Agreement reads as follows:

   2.1 The Electricity purchased under this Agreement is solely for the purpose of supplementing West Kootenay Power's resources to enable it to meet its service area load requirements and shall not be Exported or stored provided that nothing contained herein shall prohibit West Kootenay Power from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement.

3. In the Application BC Hydro seeks an order approving the replacement of Section 2.1 with the following proposed new Section 2.1:

   2.1 The Electricity purchased under this Agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and,

   (a) shall not be Exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement; and

(b) shall not be sold to any FortisBC customer that is selling self-generated electricity which is not in excess of its load.

For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from arbitraging between PPA embedded-cost electricity and market prices.

(See Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008, p.5; Exhibit B-3, Attachment 1 (Draft Order) to BC Hydro letter to the Commission dated September 30, 2008; and Exhibit B-5, BC Hydro response to Commission IR 1.1.1)

4. The essence of BC Hydro's complaint, as reflected in the Application, is that the Power Purchase Agreement should – but does not currently – prevent customers of FortisBC from "arbitraging" between the cost of power supplied by BC Hydro pursuant to the Power Purchase Agreement and market prices for exported power. As BC Hydro states in Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008, at p. 2:

> … the objective of BC Hydro's application below is to protect itself from arbitrage….

and, further, at p. 5:

> The application is solely to address BC Hydro's concerns about arbitrage of RS 3808 power by FortisBC customers that export their self-generated power.

II. OVERVIEW OF FORTISBC SUBMISSION

5. FortisBC opposes the Application for the following reasons (each of which is explained in further detail in Part IV below):

(a) First, neither the Power Purchase Agreement as a whole, nor Section 2.1 thereof in particular, is a "rate", as that term is used in Section 58 of the Act. Section 58 allows the Commission to amend a contract of a public utility relating to a "rate" if the contract is "unjust, unreasonable, insufficient, unduly discriminatory or in contravention of (the) Act, the regulations or any other law". While the Power Purchase Agreement contains certain provisions that relate to BC Hydro Rate Schedule 3808 ("**RS 3808**"), it also contains a number of provisions that do not relate to RS 3808. Section 2.1 is among those provisions that do not relate in any meaningful way to RS 3808. Accordingly, Section 58 does not afford to the Commission jurisdiction to approve the amendment to Section 2.1 of the Power Purchase Agreement that is sought in the Application.

(b) Second, even if the Power Purchase Agreement were a "rate", BC Hydro has not demonstrated that the Power Purchase Agreement is "unjust, unreasonable, insufficient, unduly discriminatory or in contravention of (the) Act, the regulations or any other law". BC Hydro alleges that to the extent it is obliged, in order to support the export activities of FortisBC's customers, to provide replacement power at embedded cost rates under the Power Purchase Agreement, it will suffer a loss. Even if this allegation were true (which FortisBC says BC Hydro has not proven), it would not warrant intervention by the Commission

under Section 58. That is because the Power Purchase Agreement obliges BC Hydro to provide to FortisBC at all times up to 200 MW of capacity and associated energy for the term of the Power Purchase Agreement. By its own admission, BC Hydro will not be obliged to provide any incremental capacity as a result of the export activities of FortisBC customers. Accordingly, BC Hydro will be called upon to deliver only that amount of capacity it has already agreed to make available to FortisBC. If the cost to BC Hydro of acquiring power to meet its obligations under the Power Purchase Agreement exceeds the revenue it derives from re-sale to FortisBC, then while the situation (from BC Hydro's perspective) may be undesirable, it is not in itself grounds for invoking a remedy under Section 58. BC Hydro is still getting exactly what it contracted for in the Power Purchase Agreement. But in any event, as noted above, the export activities of FortisBC customers do not oblige BC Hydro to provide any such incremental capacity. Moreover, BC Hydro has failed to demonstrate that it will suffer any material loss in connection with any incremental energy it may be obliged to provide. The calculations BC Hydro has presented in an effort to demonstrate the magnitude of its alleged loss are based on assumptions that are, in FortisBC's submission, inappropriate in the circumstances. FortisBC's own calculations, which are based on assumptions that FortisBC believes are more reasonable, show not only that BC Hydro may not necessarily incur any material loss in connection with its provision of replacement energy but may, in fact, be able to earn a profit from its provision of such energy.

(c) Third, it should be noted that the terms upon which FortisBC agreed that its use of power supplied by BC Hydro pursuant to the Power Purchase Agreement would be restricted were negotiated with BC Hydro as part of a larger commercial bargain. If, therefore, BC Hydro wishes to restrict even further FortisBC's use of such power, it should seek to do so in the context of the parties' currently on-going negotiations for a renewed Power Purchase Agreement, and not through an application under Section 58.

(d) Fourth, although disguised as a narrow application to amend the Power Purchase Agreement, in reality the Application represents an improper attempt to exert BC Hydro control over the use of self-generated power by third party customers of FortisBC. Section 58 confers on the Commission jurisdiction to amend the rate-related provisions of a contract between a public utility and its own customer(s); it does not allow the Commission to mandate what use may be made by persons not party to that contract of their own self-generated power.

(e) Fifth, whether and within what constraints self-generating customers in FortisBC's service territory may have access to the power export market in British Columbia is not an issue which should be resolved in the narrow context of an application under Section 58. Rather, it is properly a matter for government policy-makers to decide, on the basis of policy developed on a province-wide basis.

III. BACKGROUND – POWER COORDINATION AGREEMENT

6. FortisBC supplies power in the ordinary course to the City of Nelson pursuant to an Agreement for the Supply of Electricity Wholesale Service between FortisBC and the City of Nelson dated as of the 1st day of November, 2004 (the "**Wholesale Supply Agreement**") and pursuant to FortisBC Inc. Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan Areas, Rate Schedule 41. The Wholesale Supply Agreement is filed in these proceedings as Exhibit C4-7, Attachment 3 to the Evidence of Dan Egolf on behalf of FortisBC.

7. The City of Nelson also owns and operates its own electricity generating facilities (see Recital B of the Power Coordination Agreement (as hereinafter defined) attached to Exhibit C4-3, FortisBC letter to the Commission dated June 24, 2008.

8. FortisBC and the City of Nelson have entered into a Power Coordination Agreement (the "**Power Coordination Agreement**") made as of the 14th day of May, 2008. The Power Coordination Agreement sets out the terms and conditions under which the City of Nelson may export its self-generated power while it is purchasing from FortisBC power to meet its own load requirements. The Power Coordination Agreement is filed in these proceedings as an attachment to Exhibit A-2, Commission letter to BC Hydro dated June 25, 2008, and as an attachment to Exhibit C4-3, FortisBC letter to the Commission dated June 24, 2008.

9. The Power Coordination Agreement contains (among others) the following provisions:

> **2.1 Export of Nelson Power.**
>
> FortisBC acknowledges that pursuant to an agreement (the "Energy Marketing Agreement") between Nelson and its energy marketer (the "Energy Marketer"), Nelson may from time to time make available to the Energy Marketer capacity and energy ("Nelson Power") produced by Nelson at its generating facility (the "Nelson Generating Facility") at Nelson, British Columbia, for sale by the Energy Marketer to counterparties in Canada or the United States of America.
>
> **2.2 Maximum Nelson Power Exports.**
>
> In no circumstance will Nelson make available or agree to make available to the Energy Marketer, for sale pursuant to the Energy Marketing Agreement, Nelson Power in an amount that exceeds, in respect of any hour, the maximum amount of Nelson Power available during that hour.
>
> ….
>
> **2.5 Nelson's Power Purchases from FortisBC.**
>
> Nelson will purchase from FortisBC, pursuant to Rate Schedule 41 of FortisBC's Electric Tariff B.C.U.C. No. 1 (as amended or replaced from time to time), any power Nelson requires to replace such Nelson Power as Nelson may have made available or

agreed to make available to the Energy Marketer for sale pursuant to the Energy Marketing Agreement and that Nelson would otherwise have used to serve Nelson's load.

2.6 Use Of Power Purchased from FortisBC.

Nelson will use any and all power purchased from FortisBC pursuant to this Agreement solely to serve Nelson's load.

2.7 Nelson Availability Notices.

Before making available to the Energy Marketer, for sale pursuant to the Energy Marketing Agreement, any Nelson Power (the "Available Nelson Power") in respect of any period (the "Relevant Period"), Nelson will first provide to FortisBC a notice (an "Availability Notice") setting out the amount of such Available Nelson Power and the particulars of the Relevant Period. FortisBC acknowledges and agrees that Nelson may give any Availability Notice to FortisBC directly, or by causing the Energy Marketer to give the Availability Notice on Nelson's behalf. Any Availability Notice given by or on behalf of Nelson:

(a) on a real-time basis, must be given to FortisBC's generation dispatcher by telephone; or

(b) on a long-term basis, must be given to FortisBC's Operations Engineer and Manager, System Control, in writing.

2.8 FortisBC Election.

Upon receipt of an Availability Notice, FortisBC may elect:

(a) to require Nelson to use the Available Nelson Power specified in such Availability Notice to serve Nelson load, to the extent that FortisBC would incur a loss to replace such Available Nelson Power; or

(b) to implement the schedule or schedules provided by Nelson for the proposed sale pursuant to the Energy Marketing Agreement of the Available Nelson Power specified in such Availability Notice.

2.9 Nelson Indemnity.

If, despite an election by FortisBC pursuant to Section 2.8(b) to require Nelson to use Available Nelson Power to serve Nelson load, Nelson instead uses such Available Nelson Power for a purpose other than to serve Nelson load (including by making such Available Nelson Power available to the Energy Marketer for sale pursuant to the Energy Marketing Agreement), then in such case (a "Nelson Decision") Nelson will indemnify and save harmless FortisBC from and against any and all losses, damages, expenses (including fees and disbursements of counsel), liabilities, costs, claims, suits, actions, demands, judgments, settlements and penalties of every kind, at any time suffered or incurred by FortisBC, to the extent arising directly or indirectly from such Nelson Decision.

Other than as set out in the foregoing paragraph, Nelson will not be responsible or liable in any way to FortisBC for any consequence of Nelson dealing with Available Nelson Power as contemplated in this Agreement.

IV. ARGUMENT OF FORTISBC

10. FortisBC opposes the Application for the reasons summarized in paragraph 5 above. This Final Submission addresses each of those reasons in turn.

A. The Power Purchase Agreement is not a "rate"

11. Neither the Power Purchase Agreement as a whole, nor Section 2.1 thereof in particular, is a "rate", as that term is used in Section 58 of the Act. Section 58 allows the Commission to amend a contract of a public utility relating to a "rate" if the contract is "unjust, unreasonable, insufficient, unduly discriminatory or in contravention of (the) Act, the regulations or any other law". While the Power Purchase Agreement contains certain provisions that relate to RS 3808, it also contains a number of provisions that do not relate to RS 3808. Section 2.1 is among those provisions that do not relate in any meaningful way to RS 3808. Accordingly, Section 58 does not afford to the Commission jurisdiction to approve the amendment to Section 2.1 of the Power Purchase Agreement that is sought in the Application.

Scope of the definition of "rate" in the Act

12. Section 58 of the Act reads as follows:

> 58 (1) The commission may,
>
> (a) on its own motion, or
>
> (b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,
>
> after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.
>
> (2) If the commission makes a determination under subsection (1), it must, by order, set the rates.
>
> (3) The public utility affected by an order under this section must
>
> (a) amend its schedules in conformity with the order, and
>
> (b) file amended schedules with the commission.

13. The term "rate" is defined in Section 1 of the Act as follows:

> "rate" includes

(a) a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility,

(b) a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate, and

(c) a schedule or tariff respecting a rate.

14. The term "compensation" (referred to in paragraph (a) of the definition of "rate") is defined in Section 1 of the Act as follows:

> "compensation" means a rate, remuneration, gain or reward of any kind paid, payable, promised, demanded, received or expected, directly or indirectly, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it.

15. BC Hydro takes the position that the Power Purchase Agreement is a tariff and, hence, a "rate", as that term is used in Section 58 of the Act (see Exhibit B-7, BC Hydro response to FortisBC IR 1.2.1.1). In support of this position, BC Hydro notes that the Power Purchase Agreement was filed as a tariff supplement in accordance with Commission Order No. G-85-93 (see Exhibit B-7, BC Hydro response to FortisBC IR 1.2.1.1).

16. FortisBC acknowledges that Order No. G-85-93 directed that the Power Purchase Agreement be so filed, in the following words:

> B.C. Hydro is directed to file, in a timely fashion, an executed copy of the Amended Power Purchase Agreement **in tariff supplement form**, along with Rate Schedule 3808 – Transmission Service – West Kootenay Power Ltd. (emphasis added)

17. FortisBC acknowledges further that the Power Purchase Agreement was filed with the Commission in tariff supplement form, as "BC Hydro Tariff Supplement No. 3". However, FortisBC submits that merely because the Power Purchase Agreement was assigned a certain nomenclature (ie. "BC Hydro Tariff Supplement No. 3") for filing purposes under the Act does not necessarily render the document a "rate". It is the substance of the Power Purchase Agreement, not its form, that should be determinative of the question whether the Power Purchase Agreement is a "rate" for the purposes of the Act. As the court said in *Crestbrook Pulp and Paper Co. v. Columbia Natural Gas Ltd.* (1978), 87 D.L.R. (3d) 248 (BCCA) at p. 253: "While a contract may be filed and approved as part of a rate schedule, it does not thereby lose its identity as a contract".

The definition of "rate" distinguishes between core and extended meanings

18. The term "rate", as defined by the Act, is comprised of three components (described, respectively, in paragraphs (a), (b) and (c) of the definition).

The first component, described in paragraph (a) of the definition, is a "rate, fare, toll, charge, rental or other compensation". FortisBC submits that this language represents the core concept of the definition: a monetary charge or price. Each of the terms used in

paragraph (a) conveys a meaning directly associated with such a monetary charge or price.

The second component, described in paragraph (b) of the definition, is a "rule, practice, measurement, classification or contract … relating to a rate" (emphasis added).

The third component, described in paragraph (c) of the definition: a "schedule or tariff respecting a rate" (emphasis added).

19. The core component of the term "rate", set out in paragraph (a), is expanded by paragraphs (b) and (c) to include certain things that are "relating to" or "respecting" a "rate". To avoid imputing circularity of logic to the Act, FortisBC submits that the references to "rate" in each of paragraphs (b) and (c) ought to be interpreted as references to "rate" in the narrower sense of monetary charge or price.

Extended meaning of "rate" requires a link to price

20. FortisBC acknowledges that the definition of "rate" is inclusive. That is to say that the expressly-enumerated components of the definition do not represent a closed set. But that does not mean that the scope of the definition is unlimited.

21. In relation to paragraphs (b) and (c) of the definition, FortisBC submits that it is only to the extent that a "rule, practice, measurement, classification or contract relates to", or a "schedule or tariff" respects, a price charged for a public utility's services that such rule, practice, measurement, classification, contract, schedule or tariff is, itself, also a "rate" for the Act's purposes. Conversely, in FortisBC's submission, to the extent that a "rule, practice, measurement, classification or contract" does not relate to a price, or a schedule or tariff does not respect a price, it is not itself a "rate". Accordingly, the mere fact that a contract contains provisions relating to price does not, inevitably, force one to conclude that the entire contract constitutes a "rate". It is only those provisions of the contract that relate to a price for a public utility's services that also constitute a "rate".

22. Moreover, for a contractual provision to "relate to" a price for a public utility's services, there must be some logical and meaningful connection between the provision and such price. The courts in British Columbia have held that the use of the phrase "is related to" in legislation indicates there must be some logical, reasonable connection (see, for example, *Haskett* v. *Insurance Corporation of British Columbia* (1990), 71 DLR (4th) 756, 1990 CanLII 335 (BCCA)).

23. FortisBC acknowledges that RS 3808 is, both in form and substance, a "rate" for the purposes of Section 58 of the Act. FortisBC does not agree, however, that the Power Purchase Agreement is, in its entirety, also a "rate" for the purposes of the Act. The Power Purchase Agreement sets out **all of the terms and conditions** that govern the relationship between BC Hydro and FortisBC in respect of FortisBC's purchase of power from BC Hydro. Some of those terms relate to RS 3808 while others do not in any meaningful way. FortisBC submits that it is only those provisions of the Power Purchase Agreement that have a logical and reasonable connection to RS 3808 that themselves also constitute a "rate" for purposes of the Act.

Section 58 uses "rate" in its core meaning

24. In the context of Section 58, in particular, FortisBC submits that it is not reasonable to interpret the term "rate" as encompassing the whole of a contract that merely happens to have within it one or more provisions that "relate to" or are "respecting" price.

25. Section 58 itself contains certain express clues indicating that its intended scope is limited to "rates" in the sense of "price". For example, Section 58(1)(b) uses the phrases "existing rates in effect and collected" and "rates charged or attempted to be charged" (emphases added). One might speak of a monetary charge or price being "collected" or "charged", but one does not normally speak of a contract (or a non-financial term or condition of that contract) as being "collected" or "charged".

26. Further, Section 58(2) states that if the Commission makes a determination under this provision, it must "set the rates" (emphasis added). Again, whereas one might speak of "setting" a monetary charge or price, one would not normally speak of "setting" a contract, or a non-financial term or condition of that contract.

27. Moreover, Section 58(3), which addresses the public utility's responsibility when it is subject to an order made by the Commission under Section 58, states specifically that the public utility must "amend its schedules in conformity with the order" (emphasis added) and file those amended schedules with the Commission. It does not say that the public utility must amend one or more of its "contracts".

28. In FortisBC's submission, therefore, this express language in Section 58(3) is telling: it indicates that the scope of Section 58 is limited to the monetary charge or price-related aspects of a contract.

The Commission recognizes that a contract is not a "rate" for all purposes

29. The Commission, too, distinguishes between the "rate", or monetary charge aspects of a contract on the one hand, and other "terms and conditions", or non-monetary charge aspects of a contract on the other. In its decision *In the matter of an Application by British Columbia Hydro and Power Authority for Rate Schedule 3808 and revised Power Purchase Agreement with West Kootenay Power Ltd.* dated April 22, 1993 (the "**1993 Decision**"), the Commission repeatedly distinguishes between the "rate" (in its narrow meaning of price) aspects of a contract and the other "terms and conditions" of a contract. For example:

    (a) on page ii of the 1993 Decision the Commission says:

    > "Rate 3807 will be terminated and replaced by a new rate … and an amended Power Purchase Agreement" (emphasis added);

    (b) later on page ii of the 1993 Decision, the Commission says:

    > "(T)o accompany Rate 3808, the Commission directs BC Hydro and WKP to negotiate an amended Power Purchase Agreement" (emphasis added);

(c) further, at that same page, the Commission says the following:

> The Commission will ensure, upon receipt of a filed agreement, that the terms and conditions thereof, including the rates therein, are reflective of fair market arrangements (emphasis added);

(d) on page 4 of the 1993 Decision, the Commission says the following:

> The rates, terms and conditions of a long-term PPA between BC Hydro and WKP became the subjects a public hearing in 1986 (emphasis added);

(e) on page 7 of the 1993 Decision, the Commission says the following:

> In the early months of 1990, BC Hydro and WKP began negotiations for new rates, terms and conditions, but were unable to agree before the end of the transition period (emphasis added); and

(f) on page 31 of the 1993 Decision, the Commission says the following:

> The Commission will ensure, upon receipt of a filed agreement, that the terms and conditions thereof, including the rates therein, are reflective of fair market arrangements (emphasis added).

The cases under Section 58 are concerned with "rate" in its core meaning

30. In FortisBC's submission, Section 58 is intended to allow the Commission to address an imbalance in the financial construct between a utility and its ratepayers, as that construct is expressed in the "rates" (that is, the price to be paid per unit of power purchased) that the utility charges. Specifically, FortisBC submits that Section 58 affords jurisdiction to the Commission to amend the prices to be charged, and contractual provisions that directly relate to the prices to be charged, for a public utility's services. But, the Commission cannot under Section 58 amend contractual provisions that are not directly tied to price. The fact that Section 58 is focused on price is demonstrated by the decided cases under that provision (and its predecessor sections).

31. The Court of Appeal's decision in *Re Eurocan Pulp & Paper Co. Ltd. and British Columbia Energy Commission et al* (1978), 87 D.L.R. (3d) 727 (BCCA) exemplifies this approach. In that case, the appellant company had appealed a decision of the respondent Commission increasing the rate charged by Pacific Northern Gas Company Limited for natural gas service provided to the appellant. The court described the nature of the case as follows (at p. 728):

> The appellant … appeals, with leave of this Court, from an order of … (the Commission), made on March 3, 1977, whereby the latter indicated that it would accept for filing on an interim basis an amended rate schedule incorporating an increase of $0.08 per Mcf applicable to the consumption of natural gas for all classes of service on and after February 1, 1977.

Although the court noted there was some lack of clarity in the respondent utility's application with respect to which section of the Act provided the basis for the requested rate increase, the court found that the Commission had jurisdiction under Section 38 (now Section 58). At page 731 the court said the following in this regard:

> Under s. 38 it seems clear that the Commission would have jurisdiction to entertain a complaint that existing rates in effect and collected are unjust or insufficient. In that event it would clearly have jurisdiction to correct the injustice or the insufficiency.

In FortisBC's submission, this case reflects the usual and proper application of the Commission's jurisdiction under Section 58.

32. In *BC Gas Utility Ltd. v. British Columbia Hydro and Power Authority et al*, 1999 CanLII 1441 (BCCA), the court dealt with an application to amend a gas supply contract provision directly related to price. This case, too, illustrates the exercise of the Commission's intended jurisdiction under the Act. The court described the factual background of the case in the following terms (at paragraphs 2-3):

> At the time when the Hydro Authority's Lower Mainland natural gas distribution system was "privatized", and became the property of what is now the respondent BC Gas Utility Ltd., in 1988, the new gas utility became bound by a 10-year contract under which it is required to make gas available until 1998 on an "interruptible" basis to the Hydro Authority's gas-fired Burrard thermal electric power generating plant.
>
> The contract, dated September 29, 1988, and approved by Order-in-Council for rate-making purposes the following day, establishes a formula under which the gas is to be priced and sets out, "subject to regulatory approvals which apply from time", the priorities of the authority in relation to other interruptible users and uses for the purpose of determining when gas will be available to it. The British Columbia Utilities Commission, which now has broad regulatory jurisdiction over both utilities, sought by the decision which is the subject of this appeal to adjust the language of the agreement. Its decision would give effect to the intent of the terms of the agreement as to price in light of changed circumstances resulting from governmental "de-regulation" of wholesale purchases of natural gas. The decision also effects changes of substance in the terms of the agreement having to do with priority of supply, with the result of reducing the authority's priority.

33. In the course of its decision the court addressed the question whether the Commission had jurisdiction not only to adjust the unit price for gas provided by the utility, but also to adjust priority among the utility's customers. In this regard, the court said the following at paragraph 11:

> I turn, then, to the issue of most consequence--the Commission's jurisdiction over the priority to be given to the authority's requirements as against other "interruptible" users and uses of gas available in the system.

34. Importantly, in FortisBC's submission, the court found a direct link between the contractual provisions relating, respectively, to price and priority. In this regard, the court said at paragraph 13:

> Since the standing of an "interruptible" customer on the utility's priority list is obviously a factor of consequence in putting a value on the service provided under a contract for interruptible supply, price and priority are related, and both must in my view be regarded as part of the established "rate" for regulatory purposes. A lowering of priority, such as that effected by the amendments directed by the Commission in this case, results in a customer receiving a lower value of service. The result for the gas utility of lowering the authority's priority is that the utility may be able to make more remunerative use of gas available in its system in excess of firm commitments, a benefit which in a properly-regulated utility flows by way of lower rates to other customers. (emphasis added)

35. The court described the contractual changes directed by the Commission and then said the following at paragraphs 14-15:

> In the normal performance of its regulatory function the Commission would in my view clearly be entitled to direct such change in a supply agreement between utility and customer, whether on initial filing as a "rate" or on later review.
>
> I say this because the *Utilities Commission Act* provides the Commission with authority over a very wide range of contractual and other matters relating to the utilities within its jurisdiction, including the terms of supply and price provided for in agreements entered into with its customers. The Act gives to the Commission the power to make rules governing such agreements and to review and reject agreed rates at any time in carrying out its duty of establishing and maintaining rates which are neither "unjust, unreasonable, insufficient" nor "unduly discriminatory".

36. The court then identified a number of provisions of the Act under which it found the Commission had jurisdiction to make the subject alterations to the gas supply contract. Among those provisions was Section 64 (now Section 58). It is important to note that the court's broad characterization of the Commission's overall jurisdiction (quoted in the immediately preceding paragraph) derived from a review of the entire Act and not Section 64 (now Section 58) in particular. Indeed, FortisBC submits that despite the language quoted above, the court's actual decision supports FortisBC's contention that there must be a logical link or relationship to price in order for the Commission to have jurisdiction to amend other contractual terms under Section 58. If there is no demonstrated link between a contractual provision and a price for power, then there can be no amendment of that contractual provision under Section 58.

Section 2.1 of the Power Purchase Agreement does not "relate to" a rate

37. FortisBC submits that Section 2.1 of the Power Purchase Agreement, in particular, is not related to RS 3808. There is no express or implicit tie in the Power Purchase Agreement between the export restriction in Section 2.1 and the price for power set out in RS 3808.

38. The Commission's direction in the 1993 Decision to BC Hydro and FortisBC with respect to the parties' negotiation of the Power Purchase Agreement reflects that the Commission did not view the export issue as necessarily related to or respecting "rate(s)". Specifically, at page 29 of the 1993 Decision, the Commission said the following:

> The Commission directs B.C. Hydro and WKP to negotiate amendments to the PPA to incorporate the Commission's findings and directions as set out in other sections of this Decision. In addition, B.C. Hydro and WKP are directed to negotiate such further amendments as may be necessary to address those ancillary issues which are of concern to them.
>
> ....
>
> To assist in this process, the Commission offers the following observations concerning the evidence presented at the hearing. These observations are not intended to restrict the negotiations between B.C. Hydro and WKP, or the subsequent comments by the other registered intervenors. Instead, they are offered simply to facilitate the resolution of some of the items that, in the context of prior discussions, seemed to be points of contention between B.C. Hydro and WKP.

39. Among the "observations" the Commission makes is the following, in relation to export sales:

> With regard to either the storage or export sales of energy and capacity which WKP purchases from B.C. Hydro the Commission's impression of the evidence submitted to date indicates that such practices should be prohibited if there is sufficient flexibility in the monthly billing of entitlements and the 50 G.Wh account to accommodate over nominations or prescheduling.

There is nothing in this "observation" that is in any way expressly or implicitly tied to the "rate" for power to be charged under the Power Purchase Agreement. Nor is there anything in it that purports to address the export of self-generated power by customers of FortisBC.

40. FortisBC submits that BC Hydro has not demonstrated that there is any link between Section 2.1 of the Power Purchase Agreement and RS 3808 that would justify amendment of the terms of the export restriction contained in that provision.

41. FortisBC notes what appears to be a suggestion, made *en passant* by BC Hydro in paragraph 35 of its Final Argument, that Section 28(3) of the Act may somehow afford the Commission jurisdiction to amend the Power Purchase Agreement in the manner requested by the Application. FortisBC believes that Section 28(3) is, in fact, irrelevant to these proceedings, and notes further that BC Hydro has itself clearly stated that the Application is brought solely pursuant to Section 58 of the Act.

B. <u>Even if the Power Purchase Agreement is a "rate", it is not "unjust, unreasonable, insufficient, unduly discriminatory" or otherwise unlawful</u>

42. Even if the Power Purchase Agreement were a "rate", BC Hydro has not demonstrated that the Power Purchase Agreement is "unjust, unreasonable, insufficient, unduly discriminatory or in contravention of (the) Act, the regulations or any other law". BC Hydro alleges that to the extent it is obliged, in order to support the export activities of FortisBC's customers, to provide replacement power at embedded cost rates under the Power Purchase Agreement, it will suffer a loss. Even if this allegation were true (which

FortisBC says BC Hydro has not proven), it would not warrant intervention by the Commission under Section 58. That is because the Power Purchase Agreement obliges BC Hydro to provide to FortisBC at all times up to 200 MW of capacity and associated energy for the term of the Power Purchase Agreement. By its own admission, BC Hydro will not be obliged to provide any incremental capacity as a result of the export activities of FortisBC customers. Accordingly, BC Hydro will be called upon to deliver only that amount of capacity it has already agreed to make available to FortisBC. If the cost to BC Hydro of acquiring power to meet its obligations under the Power Purchase Agreement exceeds the revenue it derives from re-sale to FortisBC, then while the situation (from BC Hydro's perspective) may be undesirable, it is not in itself grounds for invoking a remedy under Section 58. BC Hydro is still getting exactly what it contracted for in the Power Purchase Agreement. But in any event, as noted above, the export activities of FortisBC customers do not oblige BC Hydro to provide any such incremental capacity. Moreover, BC Hydro has failed to demonstrate that it will suffer any material loss in connection with any incremental energy it may be obliged to provide. The calculations BC Hydro has presented in an effort to demonstrate the magnitude of its alleged loss are based on assumptions that are, in FortisBC's submission, inappropriate in the circumstances. FortisBC's own calculations, which are based on assumptions that FortisBC believes are more reasonable, show not only that BC Hydro may not necessarily incur any material loss in connection with its provision of replacement energy but may, in fact, be able to earn a profit from its provision of such energy.

The "test" under Section 58 of the Act

43. FortisBC submits that, for the Application to succeed, BC Hydro must demonstrate that the Power Purchase Agreement is "unjust, unreasonable, insufficient, unduly discriminatory or in contravention of (the) Act, the regulations or any other law". BC Hydro alleges in the Application that it suffers adverse impacts, both commercial and technical in nature, as a result of the City of Nelson's export activities. FortisBC submits that BC Hydro has failed to demonstrate that the Power Purchase Agreement has any such impact on BC Hydro or its ratepayers.

Alleged commercial impact

44. BC Hydro describes the nature of the commercial impact it says that it suffers in the following terms:

> The supply of energy by BC Hydro for exports by FortisBC customers means that BC Hydro incurs an opportunity cost, as it must replace the energy that would otherwise be available to be used for the benefit of its own ratepayers.
>
> (Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008. p. 4)

45. BC Hydro estimates that the "potential cost" to BC Hydro ratepayers "could be roughly $16.7 million per year" (Exhibit B-5, BC Hydro response to Commission IR 1.7.1). But BC Hydro provides only the most superficial "analysis" to support this calculation (see Exhibit B-5, BC Hydro response to Commission IR 1.7.1.1), and admits that "the potential cost to BC Hydro and its ratepayers could be much greater, or lower, than $16.7

million per year" (Exhibit B-5, BC Hydro response to Commission IR 1.7.1). FortisBC submits that this admission demonstrates that BC Hydro has no defensible basis for asserting it has suffered, or will suffer, any loss associated with any such provision of replacement energy.

46. FortisBC submits that BC Hydro will suffer no adverse impact associated with any provision of replacement power, either with respect to the capacity component or the energy component thereof.

(a) There is no capacity-related impact

47. FortisBC submits that its customers' export activities have no adverse impact whatsoever on BC Hydro with respect to the capacity component of power sales under the Power Purchase Agreement. If BC Hydro must supply replacement power under the Power Purchase Agreement to replace power exported by FortisBC customers, BC Hydro is not thereby obliged to increase the capacity reservation on the BC Hydro system above that which it is already obliged to make in response to the relevant nomination (made in advance) by FortisBC. BC Hydro is already contractually bound (by the Power Purchase Agreement) to reserve on its system capacity up to the 200 MW cap. The load created by FortisBC customers, irrespective of whether those customers are exporting power or using it to meet their own load, does not require any capacity in addition to that which must be committed, in any event, in accordance with the Power Purchase Agreement.

48. In its response to FortisBC Information Request 2.6.1 BC Hydro has, in fact, acknowledged that it has no exposure to incremental capacity demand as a result of City of Nelson exports. In its Information Request 2.6.1, FortisBC asked the following question:

> 2.6.1 … (C)an BC Hydro confirm that City of Nelson exports do not change the magnitude of the capacity reservation held by BC Hydro on its system in any way, since this obligation is related to the 5-year nomination only and must be held on the BC Hydro system continuously, regardless of anticipated use … ?

BC Hydro responded by saying "Confirmed." (Exhibit B-9, BC Hydro response to FortisBC IR 2.6.1)

49. BC Hydro is at no risk of having to make incremental capacity reservations on its system as a result of the export activities of FortisBC customers. Under the Power Purchase Agreement BC Hydro must make capacity reservations adequate to accommodate the nominations made, in advance, by FortisBC. Whether FortisBC customers are exporting their self-generated power or using it to meet their own load, those reservations do not change, and do not need to change. Whatever the circumstances, BC Hydro gets exactly what it bargained for in the Power Purchase Agreement.

50. FortisBC notes that in paragraph 58 of the Final Argument submitted on BC Hydro's behalf in these proceedings, the following language appears:

> In FortisBC's responses to BC Hydro IRs 3.5.9 and 3.5.10, FortisBC states its assumption that BC Hydro sets aside and reserves, unused on its system, the full amount of capacity FortisBC nominates under the PPA on a five-year basis even though FortisBC does not actually use all of that capacity. FortisBC's assumption is not correct.

In (the immediately following) paragraphs 59 through 62, BC Hydro goes on to describe its operational treatment of the 200 MW capacity commitment set out in the Power Purchase Agreement, stating in paragraph 59 that "... BC Hydro treats this load service obligation in its planning and system optimization processes in a similar fashion as its other domestic load obligations". FortisBC views the language in these paragraphs as tantamount to an admission by BC Hydro of its deliberate and systemic breach of Section 7.4 of the Power Purchase Agreement. Section 7.4 reads as follows:

> 7.4 System Supply
>
> Subject to Section 6.3 above, B.C. Hydro shall reserve on its system the amounts of capacity and associated energy resources necessary to meet the Nominated Demands, the Total Nominated Demand and the associated energy for each Nomination Period and, if requested by West Kootenay Power, shall supply capacity and associated energy up to the Nominated Demands for each Point of Interconnection and the Point of Supply for each Nomination Period.

If BC Hydro were complying with Section 7.4 of the Power Purchase Agreement, FortisBC submits that the export activities of FortisBC customers would not oblige BC Hydro to supply any incremental capacity. (Indeed, FortisBC notes that BC Hydro did confirm as much in its response to FortisBC's IR 2.6.1, despite BC Hydro's subsequent disavowal of the same in paragraph 57 of its Final Argument.) If, on the other hand, in order to take advantage of "profitable marketing opportunities" (see paragraph 62 of the BC Hydro Final Argument) BC Hydro has voluntarily adopted procedures that potentially make it more difficult for BC Hydro to meet its Power Purchase Agreement obligations or that actually constitute a breach of the Power Purchase Agreement (by unnecessarily creating an "incremental" capacity requirement in the event replacement power is required, which paragraph 62 of the BC Hydro Final Argument suggests regularly happens), the consequences should redound to BC Hydro's detriment instead of operating to the prejudice of FortisBC.

(b) There is no adverse energy-related impact

51. BC Hydro alleges that it will bear an increased cost associated with incremental energy that BC Hydro may have to supply to replace energy exported by City of Nelson (see Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008, p. 4). However, BC Hydro's calculation of the energy-related impact of the City of Nelson's export activities is so hedged about with qualifications that it is virtually meaningless. For example, in its response to Commission Information Request 1.7.1.1, BC Hydro says:

> The calculation of $16.7 million is based on an estimate of the long-term opportunity cost of new supply of 7.36 cents/kWh, as represented by the Tier 2 energy price of RS 1823. BC Hydro recognizes however, that the 7.36 cents/kWh is a proxy for the actual cost that may be incurred by BC Hydro to supply incremental PPA power to FortisBC. This can

> vary significantly over time with the potential for both higher or lower costs. (emphasis added)

(Exhibit B-5, BC Hydro response to Commission IR 1.7.1.1)

Moreover, in its response to British Columbia Old Age Pensioners Organization (the "**BCOAPO**") Information Request 2.3.3, BC Hydro says:

> BC Hydro is not able to estimate what the financial impact of the PCA would be based on BC Hydro's market price of replacing energy. The market price will vary depending on when the export is being made (time of day/month) and BC Hydro does not have any information as to when the City of Nelson will be exporting. (emphasis added)

(Exhibit B-9, BC Hydro response to BCOAPO IR 2.3.3)

52. FortisBC submits that BC Hydro's admitted uncertainty is telling. FortisBC submits that there is little likelihood BC Hydro will suffer any loss of the kind alleged. In fact, FortisBC's evidence demonstrates that if BC Hydro makes prudent power purchase decisions, it may realize a profit from its provision of replacement energy.

53. Instead of using the long-term cost of new supply to estimate the cost of providing replacement energy (as BC Hydro does in its submission), FortisBC believes it is more appropriate to use the forecast non-firm energy cost set out in BC Hydro's own 2008 Long Term Acquisition Plan. In FortisBC's submission non-firm energy more closely resembles the power BC Hydro might require to replace power exported by FortisBC's customers, and for that reason it provides a better basis for estimating the cost of such replacement power. (Non-firm energy is energy without any associated capacity, just as the replacement power that BC Hydro might be obliged to provide will be energy without any associated incremental capacity, as noted above.) Moreover, since City of Nelson export sales are market-based (that is, they are made as opportunities for sale into the export market arise), FortisBC believes that a determination of the cost of providing replacement energy in respect of such export transactions should also be market-based. The forecast cost of such non-firm energy set out in BC Hydro's 2008 LTAP is such a market-based cost. By contrast, BC Hydro's long-term cost of new supply, and the base price for energy set out in BC Hydro's 2008 Standing Offer Program, each includes a value component for capacity. Further, neither has a market-based derivation. In light, therefore, of the existence of the alternative market in British Columbia for non-firm energy which BC Hydro's 2008 LTAP appears to recognize, FortisBC believes it is not reasonable to use the pricing approach reflected either in the long-term cost of new supply or the 2008 Standing Offer Program (each of which is inclusive of capacity). Instead, FortisBC submits that the forecast cost of non-firm energy set out in BC Hydro's 2008 LTAP provides a more reasonable proxy for the cost of providing replacement energy in respect of FortisBC customer export transactions.

54. By deducting from the cost determined in accordance with the preceding paragraph the sale price of power under the Power Purchase Agreement, one can derive an amount that more accurately represents the difference between the price at which BC Hydro

purchases replacement energy and the price at which BC Hydro sells that energy to FortisBC. The applicable formula is as follows:

$45/MWh − $39.6/MWh = $5.4/MWh

55. Next, by applying BC Hydro's own estimate of combined annual energy sales to the City of Nelson and Zellstoff Celgar Limited Partnership, being 378,000 MWh (see Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008, at p.4) one can estimate the annual cost to BC Hydro (before adjustment) of replacement power, as follows:

$5.4/MWh × 378,000 MWh = $2,041,200

56. Finally, by adjusting the average purchase price to BC Hydro downward by 10% (to account for BC Hydro's market trading efficiency advantage deriving from the availability to BC Hydro of hourly opportunities), and by adjusting the sale price to FortisBC upward by 7% (to account for anticipated rate increases under the Power Purchase Agreement in 2008 and 2009), one can estimate the actual difference between BC Hydro's purchase and sale prices as follows:

($45/WMh × 0.90) – ($39.6/MWh × 1.07) = ($1.9/MWh)

57. Again applying BC Hydro's estimated annual energy sales to the City of Nelson and Zellstoff Celgar Limited Partnership, being 378,000 MWh, one can estimate the annual <u>profit</u> to BC Hydro associated with the supply of replacement energy as follows:

$1.9/MWh × 378,000 MWh = ($718,000).

(See Exhibit C4 – 7, Evidence of Dan Egolf on behalf of FortisBC, at pp. 2-3).

58. In response to FortisBC's contention that BC Hydro will not necessarily incur a loss and may, in fact, be able to realize a profit in connection with its acquisition and re-sale of energy to replace FortisBC customer exports, BC Hydro acknowledges (in paragraphs 64 to 65 of its Final Argument) that it generally seeks to optimize its "generation resources, imports and exports in consideration of load and storage conditions, on an hour-by-hour basis to maximize the value of BC Hydro's generation system for the benefit of all of its customers". Presumably, this means that BC Hydro seeks to acquire any necessary replacement energy on the most favourable terms (including as to price) possible. But BC Hydro has not offered in evidence any estimate of its own to contradict FortisBC's estimate of the market price which BC Hydro may have to pay for any such replacement energy. FortisBC submits that its estimate is credible, based on reasonable assumptions and uncontradicted by any evidence of BC Hydro.

<u>Alleged technical impact</u>

59. BC Hydro also asserts that it will suffer loss resulting from certain technical impacts of FortisBC's arrangements with the City of Nelson. BC Hydro's principal complaint is that the variability of the energy exported by the City of Nelson will potentially "impact BC

Hydro's hourly supply/demand balance" (see Exhibit B-4, BC Hydro letter to the Commission dated July 16, 2008, p.4). In this regard, BC Hydro says the following:

> In order to optimize BC Hydro balance point within the multitude of system operating constraints (including maximum generation, minimum generation, maximum energy, rotational inertia and others) close and rapid communication would be required between the scheduling/exporting parties and BC Hydro system operations personnel.
>
> BC Hydro has no authority to require the City of Nelson to provide the timely information that BC Hydro would need to include in its optimization process. Also, in BC Hydro's experience this information is very difficult to obtain from third parties on a reliable basis. Therefore, it is considered likely that these new City of Nelson exports would require a 9MW - 16MW "operating margin increase" in the dispatch of BC Hydro's generation resources which would ultimately result in a reduction of BC Hydro's operating efficiency.

(Exhibit B-4, BC Hydro Letter to the Commission dated July 16, 2008, p. 4)

60. BC Hydro also complains that it might have to provide ancillary services in connection with City of Nelson exports, since it is "unclear" to BC Hydro whether FortisBC is itself providing such ancillary services. (See Exhibit B-5, BC Hydro response to Commission IR, 1.5.1.1)

61. In FortisBC's view, any concern that BC Hydro has in either regard can be resolved by improved sharing of information. (See Exhibit C4–7, Evidence of Dan Egolf on behalf of FortisBC, p. 3.) FortisBC believes that such improved communication would substantially remove BC Hydro's uncertainty. This could be a task for the Technical Committee contemplated by the Power Purchase Agreement. In any event, FortisBC submits that such operating considerations should not be determinative of the issue whether Section 58 of the Act ought to be invoked to amend the Power Purchase Agreement.

62. Given the foregoing, FortisBC submits that BC Hydro has not demonstrated, and cannot demonstrate, that the operation of the Power Purchase Agreement causes BC Hydro to suffer any real or measurable loss in connection with the provision of replacement energy. Certainly, BC Hydro has not demonstrated that the Power Purchase Agreement operates in a manner that is "unjust, unreasonable, insufficient, unduly discriminatory or in contravention of (the) Act, the regulations or any other law".

63. If the Commission were to grant the Application, however, the customers of FortisBC would certainly be harmed. As demonstrated by the submissions of City of Nelson and Zellstoff Celgar Limited Partnership in these proceedings, FortisBC's self-generating customers would particularly suffer.

C. <u>Any further export restrictions should be for BC Hydro and FortisBC to negotiate</u>

64. The terms upon which FortisBC agreed that its use of power supplied by BC Hydro pursuant to the Power Purchase Agreement would be restricted were negotiated with BC Hydro as part of a larger commercial bargain. If, therefore, BC Hydro wishes to restrict

even further FortisBC's use of such power, it should seek to do so in the context of the parties' currently on-going negotiations for a renewed Power Purchase Agreement, and not through an application under Section 58.

65. In the 1993 Decision, the Commission refrained from giving specific direction to BC Hydro and FortisBC in respect of certain power purchase agreement-related issues, leaving the parties free to negotiate a mutually-acceptable resolution. As noted above, the Commission only made an "observation" about the export issue, leaving it to BC Hydro and FortisBC to settle the nature and scope of the applicable restriction in the context of their overall negotiations. FortisBC submits that, as between BC Hydro and FortisBC, resolution of the issue raised by the Application should not be imposed by the Commission but should be left to the parties to negotiate in the context of their currently ongoing negotiations for renewal of the Power Purchase Agreement.

66. The Power Purchase Agreement was negotiated by two sophisticated parties, each being well-informed about the dynamics of the energy market in which it was (and is) a participant and each devoting substantial resources to the negotiation process. The parties also had the benefit of advice from external counsel and, of course, guidance and direction from the Commission. BC Hydro was, apparently, sufficiently satisfied with the terms it negotiated with FortisBC that it was prepared to execute the Power Purchase Agreement. Now, with more than four years left in the term of that agreement, BC Hydro seeks to secure for itself – unilaterally and without negotiation – a further contractual advantage that will inevitably operate to the detriment of FortisBC and its ratepayers. In FortisBC's submission, the balancing of interests between the parties on the issue raised by the Application should be done by the parties themselves, in the context of negotiations that encompass all issues relevant to the supply of power by BC Hydro to FortisBC.

67. It is one thing for BC Hydro to require, as a condition to its agreement to enter into the Power Purchase Agreement, that FortisBC refrain from arbitraging power purchased thereunder. (This FortisBC agreed to do in 1993, as Section 2.1 reflects.) But it is a very different thing for BC Hydro to attempt to have such a restriction imposed by the Commission. It is not, in FortisBC's submission, the kind of result Section 58 was intended to accomplish.

68. FortisBC believes the export restriction issue should be addressed in the same manner BC Hydro suggests that the Power Purchase Agreement rate structure issue should be addressed. In response to the inquiry of the Commercial Energy Consumers Association of British Columbia (Exhibit B-9, BC Hydro response to Commercial Energy Consumers Association of British Columbia IR 2.1.2) as to whether BC Hydro might be willing to consider implementing a changed rate structure for FortisBC, BC Hydro said (in part) the following:

> BC Hydro and FortisBC have been discussing the changes that ought to be made for a renewed agreement after the PPA expires in 2013. Those discussions are at a relatively early stage. BC Hydro would not be in favour of the BCUC considering changes to the structure of the PPA's energy and capacity charges in isolation from the other issues that are being discussed in connection with the renewal of the PPA.

In the same way, FortisBC submits that the issue whether there should be any further export restriction included in the Power Purchase Agreement ought to be left for BC Hydro and FortisBC to work out in the context of their over-all negotiations for the renewal of the Power Purchase Agreement. It should not be subject to a mandated resolution by the Commission, arrived at in isolation from the other issues the parties are discussing.

D. The Application improperly attempts to control third party use of self-generated power

69. Although disguised as a narrow application to amend the Power Purchase Agreement, in reality the Application represents an improper attempt to exert BC Hydro control over the use of self-generated power by third party customers of FortisBC. Section 58 confers on the Commission jurisdiction to amend the rate-related provisions of a contract between a public utility and its own customer(s); it does not allow the Commission to mandate what use may be made by persons not party to that contract of their own self-generated power.

70. That BC Hydro's real objective in bringing the Application is to control the use of self-generated power by certain FortisBC customers is made clear by BC Hydro's response to FortisBC Information Request 1.3.2. In that Information Request (Exhibit C4-5, FortisBC IR 1.3.2), FortisBC queried whether BC Hydro would acknowledge that "if the City of Nelson were to cease self-generating power … a resulting increase in FortisBC's energy take under the Power Purchase Agreement would impact on BC Hydro's operations in essentially the same manner as if the City of Nelson were exporting power for the same period of time?" In response, BC Hydro acknowledged it would have no complaint, in the following words:

> BC Hydro would not complain in the situation outlined in the question because the energy provided under the PPA would be used to serve FortisBC's service area load and the City of Nelson would not be arbitraging BC Hydro's embedded cost supply.

(Exhibit B-7, BC Hydro response to FortisBC IR 1.3.2)

71. In light of this response, FortisBC submits that BC Hydro's real complaint is not with respect to any alleged adverse commercial impact on BC Hydro resulting from the City of Nelson's export activities. It is, rather, with respect to FortisBC customers' lawful use of (their own) self-generated power. To put it another way, the purpose of the Application is not so much to avoid "loss" as it is to prevent persons other than BC Hydro from gaining a profit (from export sales) to which BC Hydro feels it alone should be entitled.

72. That this is the true purpose of the Application is made even more plain by the fact the Application overreaches is own stated intent. Despite BC Hydro's claim that its application "is solely to address BC Hydro's concerns about arbitrage of RS 3808 power by FortisBC customers that export their self-generated power" (Exhibit B-1, BC Hydro letter to the Commission dated September 16, 2008, at p. 5), the language of BC Hydro's proposed new Section 2.1 seeks not merely to prevent FortisBC customers from exporting self-generated electricity from the FortisBC service area, but from selling self-

generated electricity (within or without the FortisBC service area). That this is deliberate is made clear from BC Hydro's responses to BCOAPO IRs 2.6.1 and 2.6.2.

73. The current Section 2.1 prohibits the "Export" (as that term is defined in the Power Purchase Agreement) or storage by FortisBC of power purchased under Power Purchase Agreement. In doing so, of course, the Power Purchase Agreement aligns itself (by agreement between the parties and acceptance by the Commission) with the Commission's "observation" in the 1993 Decision that such practices should be prohibited (see 1993 Decision at p. 29). But BC Hydro's proposed amendment to Section 2.1 represents a significant, substantive extension of the current prohibition.

74. FortisBC submits that the purpose of the proposed amendment is not within the scope of Section 58. In FortisBC's submission, Section 58 is intended to permit the balancing of interests of direct parties to power supply arrangements. It is not intended to address the balancing of interests of persons who are not party to those arrangements.

75. It is partly for this reason (in addition to the reasons given in FortisBC's response to BC Hydro Information Request 3.1.3) that FortisBC submits that the Commission's treatment of the interests of BC Hydro's customers pursuant to Commission Orders G-38-01 and G-17-02 does not provide a useful precedent in the current context. In those other cases the Commission was dealing with contractual relationships between BC Hydro and its own direct customers. Each of those contractual relationships has unique features (including, in certain cases, the provision by BC Hydro of financial or other inducements for installation and maintenance by its customer of self-generation capability – none of which have been extended to FortisBC's self-generating customers) that distinguish it from the current situation. The terms of Commission Orders G-38-01 and G-17-02, which were tailored to apply to the specific circumstances addressed therein, should not be forced onto the very different circumstances which characterize the contractual arrangements enshrined in the Power Purchase Agreement. Moreover, in the current proceedings, BC Hydro is asking the Commission effectively to impose terms on the use of self-generated power by customers of a customer of BC Hydro (in other words, persons who have no contractual relationship with BC Hydro). BC Hydro's request is beyond the intended scope of Section 58.

76. FortisBC submits that these proceedings under Section 58 do not provide the right forum for consideration of whether the scope of the export prohibition should be extended also to reach FortisBC's self-generating customers. The implications of such an extension have not been, and cannot reasonably be, fully explored in the context of these proceedings. Moreover, the fact that the Application's real impact (ie. to prohibit not just export but all sale transactions by FortisBC's self-generating customers) will reach beyond its purported impact makes the task even more difficult.

77. BC Hydro makes much of what it calls the "spirit" of the Power Purchase Agreement. Indeed, the fundamental assumption on which the Application is based is that although the Power Purchase Agreement expressly limits <u>only</u> FortisBC exports, the parties nevertheless also intended that any potential exports by FortisBC's self-generating customers (despite their not being party to the Power Purchase Agreement) would be

similarly limited (see paragraph 76 of BC Hydro Final Argument). What is problematic about this assumption is that there is no direct evidence to support it. BC Hydro is asking the Commission to extrapolate from the silence of the Power Purchase Agreement to satisfy itself that the relief sought in the Application should be granted. FortisBC submits that in these circumstances it is more reasonable to assume that since the Power Purchase Agreement does not include any limitation on the ability of FortisBC's self-generating customers to export power, the parties intended no such limitation to operate. In the discipline of statutory interpretation, where a piece of legislation expresses one thing and omits another, the courts assume that the omission was intentional. This approach is known by the maxim "*expressio unius est exclusio alterius*", which means "mention of one thing implies exclusion of another" (Blacks Law Dictionary, Sixth Edition: West Publishing Co.: St. Paul, Minn. 1990). FortisBC submits that the reasoning inherent in the courts' approach to statutory interpretation should also apply in this case. The parties to the Power Purchase Agreement negotiated and expressly stated their intentions with respect to the extent to which power exports from FortisBC's service area should be constrained. Those constraints should not now be arbitrarily extended to apply to other persons not party to the Power Purchase Agreement and other transactions not expressly contemplated by the Power Purchase Agreement.

E. The subject matter of the Application should be resolved by provincial policy-makers

78. Whether and within what constraints self-generating customers in FortisBC's service territory may have access to the power export market in British Columbia is not an issue which should be resolved in the narrow context of an application under Section 58. FortisBC submits that Section 58 is not intended to facilitate such an inquiry. But even if it were, the Commission does not have available to it in these proceedings sufficient information to enable it to balance the various competing interests.

79. The implications of the Application are potentially far-reaching for customers of FortisBC who have self-generation capability. The active intervention of the City of Nelson and Zellstoff Celgar Limited Partnership in these proceedings demonstrates that the order requested by BC Hydro has very significant implications for such persons. If their ability to use power for export is to be constrained, it should be done only after careful consideration of all of the relevant policy considerations.

80. To date, the provincial government has not seen fit to implement a policy of any kind on the issue that is the subject matter of the Application. If any such policy is to be implemented in British Columbia, it should be a matter for government policy-makers to address on a province-wide basis. Unless and until the provincial government determines it necessary or appropriate to develop such a policy, FortisBC submits that its customers should be free to participate in the export market as their facilities, operations and contractual arrangements permit.

81. This over-arching issue is properly a matter for government policy-makers to resolve on the basis of policy developed on a province-wide basis.

82. Whether FortisBC's self-generating customers should be able to access the export market and, if so, on what terms, may be a matter within the federal government's sphere of legislative power under its trade and commerce power. The issue is also within the scope of the provincial government's legislative competence. But, it is not within the proper scope of the Commission's jurisdiction under Section 58.

83. For the reasons set out above, FortisBC submits that the Application should be dismissed.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

DATED AT the City of Vancouver, British Columbia, this 23rd day of January, 2009.

FORTISBC INC.
by its legal counsel
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