

**INDEPENDENT POWER PRODUCERS OF BRITISH COLUMBIA'S**

**FINAL ARGUMENT WITH RESPECT TO**

**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY 2004/2005 and  
2005/2006 REVENUE REQUIREMENTS APPLICATION**

**AND**

**AN APPLICATION BY BRITISH COLUMBIA TRANSMISSION  
CORPORATION FOR APPROVAL OF AN APPLICATION FOR  
DEFERRAL ACCOUNTS**

**B.C. UTILITIES COMMISSION ORDERS NO. G-84-03 and G-7-04**

**JULY 21, 2004**

## Executive Summary

This is the first BC Hydro Revenue Requirement Hearing in 10 years. Many changes have occurred during this period including the formulation of the Energy Plan, the creation of the British Columbia Transmission Corporation and the resurrection of Power Smart programs. Regrettably, from the IPPBC's perspective, many of the problems and inequities that existed ten years ago are still in place and appear to be acceptable to BC Hydro. By and large, BC Hydro continues to plan its programs and expenditures without the benefit a "*level playing field*" for independent power producers. IPPs aren't being allowed to compete fairly and openly to supply BC Hydro with the electricity it requires to serve its domestic customers requirements. While BC Hydro may acknowledge some of the shortcomings of its approach, it is of little practical benefit to know that such shortcomings will be done better "*the next time*". That chorus has been heard too often in the past.

A case in point is BC Hydro's decision to import large quantities of electricity. Historically, domestic electricity supply has been provided from within the province. This is no longer the case and there isn't even a drought of the type that occurred in the early 1940's, or the late 1970's and early 1980's. BC Hydro's own analysis states that it is better to have up to 3,000 GWh of additional electricity that is available in a drought than to have to import. B.C. Hydro imported approximately 10% of the electricity it needed in 2004 and estimates it will continue to import at this level in fiscal 2005 and 2006. The estimated total cost of these imports - \$835 million, which on a unit cost basis is almost identical to what BC Hydro could have purchased domestically, produced electricity on a long term firm basis. In addition, there are all the economic benefits that would accrue to the Province of B.C. from domestically produced electricity such as taxes, investment and jobs. For the period fiscal 2002 - 2006, BC Hydro's estimated expenditures on imports are over \$1 billion.

Despite these levels of imports and related costs, the age, breakdowns and inefficiency of its Burrard Thermal plant, an improving B.C. economy and the problems that would be created in Mackenzie, B.C. if it draws down the Williston reservoir below an elevation of 2,150 feet, BC Hydro plans to acquire no more than 400 GWh of electricity for delivery by 2009. This amount is less than 1% of its requirements. BC Hydro's reliance on imports poses undue risks to its domestic consumers including, lower reliability, increased reliance on costly energy from Burrard Thermal to provide backstop energy and a greater emphasis on costly Power Smart programs.

BC Hydro's approach to "*a balanced portfolio*" amounts to placing undue reliance on higher cost options while denying IPPs the fair and open opportunity to serve load at financially attractive prices. The IPPBC submits that this is not in the public interest.

It is time for a truly level playing field where economically attractive IPPs are given the fair and open opportunity to sell BC Hydro the electricity it needs. BC Hydro cannot continue to discriminate against IPPs within a long-term planning process that is shrouded in mystery. For these reasons the IPPBC submits that BC Hydro's Resource

Expenditure and Acquisition Plan should not be approved by the BCUC without the following:

- A full written and oral public hearing on its long term Integrated Electricity Plan.
- BC Hydro has provided its full financial analysis for the Site C, Revelstoke and Mica projects.
- Inclusion of any new load displacement (generation) projects within an all source energy call.
- BC Hydro applies a common and consistent financial screening tool to all sources of supply and conservation including its Power Smart and Resource Smart projects.
- It completes and makes public a full and complete assessment of the impacts that its proposed two tier pricing system for its industrial customers will have on Power Smart projects for these customers.

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# 1. Introduction

The Independent Power Producers of B.C. ("*IPPBC*") appreciates the opportunity to participate in the British Columbia Utilities Commission's ("*BCUC*") review ("*Review*") of the BC Hydro Revenue Requirements 2004/05 and 2005/06 and 2005/2006 Application ("*Application*"). In the absence of a fully functioning competitive B.C. electricity market, it is important that organizations such as the IPPBC actively participate in these types of reviews.

It has been about ten years since BC Hydro's revenue requirements have been publicly examined. There is an extraordinary volume of information to understand and assimilate and the BCUC has a real challenge before it.

Typically, in revenue requirements hearings there is a heavy emphasis on the changed circumstances from the previous proceedings. The 10 year gap effectively precludes this type of comparison, and new baselines have to be established. Changes that have taken place in this 10 - year interval such as the formation of the British Columbia Transmission Company ("*BCTC*") also hinders direct comparisons. By necessity, virtually every aspect of BC Hydro's and BCTC's operations and management must be examined. Management and policy issues have to be looked at, and not strictly on the basis of traditional regulatory oversight.

The B.C. Government's Energy Plan ("*Plan*") adds another dimension to this oversight. The Government of British Columbia has given the BCUC the mandate to implement this plan, and the BCUC must adopt a broader than normal approach to its role as regulator so that objectives of the Energy Plan are realized. The burden of proof is on the BC Hydro ("*BCH* ") to show that it is adhering to the Plan. It is not up to the intervenors in the Review to prove on the balance of probability, that BCH isn't meeting this requirement.

Given the amount of information to analyse in the time available, and resource constraints, the IPPBC has had to carefully select the matters in the Review it pursues. Broadly, the IPPBC is concerned about how BCH, on behalf of its customers, allocates financial resources. Critical components of this allocation include the processes and analysis BCH management employs such as the financial screens that are used to compare the various electricity supply and demand alternatives. In some instances, BCH is spending too much money, e.g. Power Smart. In other instances not enough, e.g. firm contracts with IPPs. Either way, the amount of money that BCH needs to collect from its customers is affected, but it is beyond the capacity of the IPPBC to determine BCH's exact revenue requirement for 2004/05 and 2005/06 ("*Test Period*").

The Review is primarily about expenditures in the Test Period. However, decisions that are, or are not made, during this period have impacts that reach well beyond this period. For IPPs this is especially true with respect to the electricity supply acquisitions that BCH is, or is not making, during the Test Period.

1 It is simply not good enough for BCH to commit to additional processes or to do better in  
2 the future. Unless critical decisions are made now and acted upon, the IPPBC will be  
3 raising many of the same issues in some other BCUC review of BCH affairs. Some of  
4 these issues have been outstanding for close to 10 years and during this period, BCH  
5 has had ample time to get things right.

6  
7 Under the heading "*Full Public Review of IEP*", the IPPBC sets out the reason why  
8 BCH's 2004 Integrated Electricity Plan ("*IEP*") must be subject to a full, separate, public  
9 review by the BCUC. In the normal course of events, the IEP review would be  
10 completed before the revenue requirements review commenced. It is unfortunate that  
11 the correct sequence of review has not been followed. During the Review, BCH  
12 acknowledged that the process it has followed for the IEP was flawed, and that it will  
13 follow a more appropriate sequence in the future. For example, transcript reference

14  
15 TR Volume 6, page 609:

16  
17 Ms. VAN RUYVEN: Well, this is the first IEP that  
18 we've done in ten years, and I see this as an evolution.  
19 So this is the first step towards getting back into a  
20 better sequence of doing integrated electricity plan.  
21 And we've committed to do one every two years, and we've  
22 committed to do proper public consultation. We had a  
23 little bit of a tight time frame this go round in that  
24 we didn't do as much consultation as we would have  
25 liked. We basically started in the late fall and we  
26 filed the IEP in March, and we would obviously like to  
27 do more consultation.  
28

29 However, the IEP and corresponding Resource Expenditure And Acquisition Plan  
30 ("*REAP*") have been filed with the BCUC, and expenditures and plans in relation to  
31 these documents during the Test Period are to be considered and approved (or not) by  
32 the BCUC. One example is the Power Smart program. Despite the IPPBC's desire for  
33 a full IEP review, it has critically analysed this program within the confines of the Test  
34 Period.

35  
36 Similarly, BCH's requirement for new supplies of electricity is part of the IEP and the  
37 REAP. What BCH does during the Test Period is of critical importance to independent  
38 power producers ("*IPPs*"). There is a very strong difference of opinion between IPPs  
39 and BCH with respect to the amount of electricity that the utility intends to buy from IPPs  
40 during the Test Period. There are equally strong differences of opinion with respect to  
41 the amount of electricity that can be produced from the Heritage Assets, and in  
42 particular the Burrard Thermal Plant ("*Burrard*"). Also, the types of Power Smart  
43 programs and the level of associated expenditures are of great concern to the IPPBC.  
44 These differences must be settled sooner rather than later, because BCH's reliance on  
45 imports continues to grow.

46  
47 Although optimistic by nature, IPPs will not continue to spend the amounts of money  
48 that are required to evaluate electricity generation projects so they are ready to be bid  
49 into competitive acquisition processes, unless there is a realistic prospect that these

1 projects will be allowed to succeed. It is imperative that IPPs be efficiently and fairly  
 2 evaluated against all demand and supply options on a “*level playing field*” basis. The  
 3 alternative is to lose the benefits that private sector investment in generation can bring,  
 4 and to risk electricity reliability and security of supply by over reliance on imports.  
 5 Private sector investment in new generation will be made outside B.C. and in the  
 6 absence of firm import contracts, BCH's customers will be subject to price volatility.

## 9 **2. The Energy Plan**

10  
 11 As the BCUC renders its decision on the Review, it should be mindful of the aspects of  
 12 the Energy Plan that are set out below.

13  
 14 From the IPPBC's perspective, the most important cornerstones of the Plan are:

- 15 • Secure, reliable supply
- 16
- 17 • More private sector opportunities

18 Similarly, the key policy action items are:

19  
 20 #9 Electricity distributors will acquire new supply on a least-cost basis, with  
 21 regulatory oversight by the BC Utilities Commission.

22  
 23 #13 The private sector will develop new electricity generation, with BC Hydro  
 24 restricted to improvements at existing plants.

25  
 26 #15 The BC Hydro Transmission Corporation will improve access to the  
 27 transmission system and enable IPP participation in US wholesale markets.

28  
 29 #21 New rate structures will provide better price signals to large electricity  
 30 consumers for conservation and energy efficiency.

31  
 32 On page 18 of the Plan under the heading “*The Need for Energy Security*” and with  
 33 reference to the sub-headings “*B.C. needs secure reliable energy to help revitalise the*  
 34 *provincial economy*” and “*Unless new domestic supplies are developed, B.C. will*  
 35 *become more dependent on imported energy and vulnerable to price swings*” it states:

36  
 37 “In the past two years, BC Hydro was a net importer due to low water levels.  
 38 These imports were necessary to meet domestic electricity requirements.  
 39 However, over-reliance on imports at wholesale spot market prices could expose  
 40 B.C. consumers to price volatility in western power markets. The province must  
 41 develop new generation to serve rising demand or we may experience electricity  
 42 shortages similar to those in other jurisdictions.”  
 43

44 On page 19 under the sub-heading “*To avoid costly public investments, governments*  
 45 *everywhere are looking to the private sector for new energy development*” it says:

46  
 47 “Given competing priorities for public funds, the government is interested in  
 48 shifting the responsibility for new power development to the private sector. The  
 49 advent of new small-scale power plants, such as efficient combined cycle gas

1 turbines and small hydro plants, is making it easier to match electricity supply  
2 with gradually growing demand. These plants are lower risk and lower cost than  
3 the much larger facilities that were the norm of the past. Private power  
4 producers, who can compete to bring forward projects to meet B.C.'s growing  
5 demand, have the capability and core competency for developing smaller  
6 generation resources as an alternative to public investment by BC Hydro."  
7

8 On page 28 under the heading "*Secure, Reliable Supply*" and the sub-heading "*Policy*  
9 *Action #9 (new): Electricity distributors will acquire new supply on a least-cost basis,*  
10 *with regulatory oversight by the BC Utilities Commission*" it states:

11 "When deciding how to meet a projected power need, BC Hydro's distribution  
12 business will compare the costs of all potential resources, including IPP  
13 purchases, customer-owned generation, BC Hydro plant efficiency improvements  
14 (Resource Smart) conservation and energy efficiency, and firm imports ... The  
15 BC Utilities Commission will oversee the acquisition process to ensure that least-  
16 cost options are chosen consistent with an new clean energy goal..."  
17

18  
19 With reference to this requirement to compare, BCH stated,

20  
21 TR Volume 6 pages 622 - 629:

22  
23 MR. ELTON: A: Could you just explain what you mean by a financial screening  
24 tool, to make sure that I understand the question fully?  
25

26 MR. AUSTIN: Q: An example might be a plain vanilla net present value analysis  
27 of costs and revenues. I'm just looking at this at the basic financial screening  
28 level. I certainly appreciate that management has discretion to use a basic tool  
29 and then beyond that, exercise whatever judgement it wishes, subject to, in this  
30 particular instance, the wishes and desires of its regulators. Does that help you  
31 out?  
32

33 MR. ELTON: A: It does, thank you.  
34 So let me first of all explain where the  
35 large capital expenditures are and then gradually move  
36 towards the question. So they're really in three areas,  
37 three main areas, and those are generation, distribution  
38 and transmission. And it's true that in distribution  
39 there's two parts to that. There's the kind of  
40 investments we make in buying new energy and there's the  
41 kind of investments that we make in our own distribution  
42 assets. And again remembering that there will be more  
43 discussion in detail of these in each of the panels  
44 later on, but I understand your question to be a more  
45 company-wide question.  
46

47 MR. AUSTIN: Q: At the very top level of the company, the  
48 question I have for you is how does management, senior  
49 management, just get that rough screening or rough  
50 analysis before it says green light, red light, amber  
51 light with respect to any particular capital equity  
52 investment dollar-related expenditure?  
53

54 MR. ELTON: A: Right. So with respect -- so I'm going  
55 to explain briefly with respect to each of those main  
56 buckets what we do, before I answer the question  
57 directly, and I'm explain why I'm doing that as I'm  
58 doing that.  
59

With respect to generation assets first,

1 remember first of all that these are Heritage Assets, so  
2 decisions about these assets cannot be made, if you  
3 like, by evaluating them simply against a bucket of  
4 other assets. In a different business, we might be able  
5 to say for example we'd like to sell certain of our  
6 assets and invest in other assets. We don't have that  
7 option here. Our option here is to generate a certain  
8 amount of electricity from those Heritage Assets at a  
9 cost that makes sense. And so with the generation  
10 assets, it's a question of the generation group  
11 producing asset plans that show why a particular  
12 investment should be made now, versus for example  
13 letting that asset run for ten more years and then  
14 making that investment, versus perhaps in some  
15 circumstances decommissioning that investment. We can't  
16 sell them but we can decommission them if it makes sense  
17 to do that.

18 And so the screens there which Ms. Farrell  
19 will explain are the usual ones where we're looking at  
20 net present values and looking at what the effect will  
21 be on the cost of those Heritage Assets over time. And  
22 if she said yes today, or maybe I did, there was an  
23 objective of keeping the total cost of the Heritage  
24 Assets at the rate that they are now. So those are the  
25 generation assets.

26 With respect to the -- excuse me. With  
27 respect to the transmission assets, as we've discussed,  
28 they are on our balance sheet, but as we're aware,  
29 there's a different regime now where BCTC will actually  
30 come to the table and say, "These are the investments we  
31 want to make." In that area, the one thing that we and  
32 BCTC both agreed on during the negotiations that is  
33 important is that there would be a baseline audit  
34 conducted of the transmission assets, which is something  
35 that is, you know, that BCTC is working on implementing  
36 now. And that will have the effect of showing what are  
37 the priorities in terms of the transmission assets,  
38 recognizing that the process is not one that's within  
39 our control, it's one that BCTC will bring to the  
40 Commission in terms of what their priorities with an  
41 intervenor.

42 In respect to the distribution assets, we  
43 looked at those. Again, if you look at the distribution  
44 -- I'm talking about the distribution operating assets,  
45 which Panel 5 will be talking about. In terms of  
46 evaluating priorities there, you can look at net present  
47 value calculations, but really that's a bit misleading.  
48 What you're really interested in there is what is the  
49 link between the money you spend on those assets, those  
50 distribution assets and the reliability and/or customer  
51 satisfaction the customers enjoy.

52 And I was referring to that yesterday in  
53 terms of the customer base reliability program that Ms.  
54 Van Ruyven will talk about. And so I'm talking about  
55 the future, and I'll explain why in a minute. Our plan  
56 there is that we'll look at our investments in  
57 distribution assets and rank them essentially terms of  
58 what affect will they have on the customer, and that may  
59 mean that we'll make more investments over here, in one  
60 region, or one small area and less investments in a  
61 different place.

62 And the reason for that somewhat lengthy

1 answer is that the way we've structured our business, we  
2 don't think actually that a simple financial screen is  
3 appropriate for our business in the future. We think it  
4 is appropriate for us to look at those three streams and  
5 say transmission is a separate issue for specific BCUC  
6 review as I've described, but we've made progress with  
7 BCTC by making sure that the agreement required a  
8 baseline audit upfront..."

9 So what I'll say there is, we don't have that  
10 baseline audit result, or BCTC doesn't have it yet, and  
11 so there's more work to do. On the distribution side,  
12 we believe that you can't compare \$10 million on a  
13 distribution asset with \$10 million on a general asset,  
14 because again, you don't know whether the distribution  
15 expenditure is appropriate until you know what the  
16 effect will be on reliability. What I'm saying is  
17 there's another work in progress, where we are working  
18 on the customer base reliability, don't have it yet.  
19 In terms of generation again, not appropriate  
20 in our view to compare in a way that maybe 20 years ago  
21 we might have done. More appropriate to look at it on  
22 its merits and say, "This is a group of assets that we  
23 are clearly tasked to deal with, is a very specific  
24 group of assets, " almost as if they were in a separate  
25 company, and that's why the Heritage Contract was set  
26 up. And so again, it's a question of looking at  
27 project by project within the generation line of  
28 business and then overall, does the effect of this  
29 year's capital program or next year's capital program or  
30 the next next year's capital program, does it lead to a  
31 good result in terms of what the ratepayer is paying  
32 through the distribution line of business for the  
33 Heritage assets.

34 So that's our approach, which is not -- so  
35 the answer then to the question, Mr. Austin, is that we  
36 don't have one single financial screen and we don't  
37 think it's appropriate to do that given the way our  
38 business is not constructed through the regulatory  
39 structure that we now have.  
40

41 MR. AUSTIN: Q: Mr. Elton, the magic words you used in  
42 your answer were "at a cost that makes sense". If you  
43 use three financial screens, how can you compare the  
44 requirement for capital, equity, investment dollars or  
45 whatever you want to call it, across three areas if at  
46 least you don't start at a common point?  
47

48 MR. ELTON: A: Well, I mean you can, because I think you  
49 -- you know, you have to look at each line of business  
50 and what it's designed to do, and as I said, the BCTC  
51 business is separate from us. Again, we still have to  
52 -- you know, we will still be in the process, as the  
53 Commission will, as all of you will, of comparing  
54 transmission investments with generation investments,  
55 and it will be a very complex process. And there will  
56 be a number of screens applied, and the decisions that  
57 the Commission will end up making, I suggest,  
58 respectfully, won't be based on one financial screen.  
59 They'll be based on several different characteristics...  
60

61 MR. AUSTIN: Q: I certainly appreciate that, but isn't  
62 it also true that a lot of what you've just told me in

1 terms of the differences between financial screens is  
2 effectively management exercising its judgment on the  
3 basis of non-comparable financial screens?  
4

5 MR. ELTON: A: No, I think it's management exercising  
6 judgment in a way that will be increasingly transparent  
7 and that will increasingly link the financial  
8 expenditures we're making to the results of those  
9 expenditures. In the case of generation line of  
10 business, I believe that as each year goes by that the  
11 quality of capital planning and the quality of capital  
12 forecasting will continue to increase. I believe that  
13 what we have here is good and it will continue to  
14 increase. I believe on the distribution side that the  
15 link between spending and reliability, which will  
16 involve a lot of consultation with customers, will  
17 continue to give a better answer. And no, it's not a  
18 question of just management's judgment. It's a question  
19 of saying we want to make sure that everybody  
20 understands what the effect is of the expenditure.  
21 So in the end, yes, we'll apply a judgment,  
22 but for example, the judgments on customer based  
23 reliability will be informed by the views of our  
24 customer. And again, Ms. Van Ruyven will be speaking  
25 about what from a customer point of view later on. But  
26 I'm speaking now from the financial point of view.  
27 So no, I don't agree with that.  
28

29 MR. AUSTIN: Q: So as I understand it you have  
30 potentially three financial screens, and if you have  
31 those then how do you compare the investment dollar  
32 requirements in those three areas to say for example  
33 acquiring new supplies of electricity from the private  
34 sector?  
35

36 MR. ELTON: A: Well, the question of acquiring new  
37 supplies of electricity in the private sector is I think  
38 a different one from the question of investment in the  
39 generation assets that we've been talking about. So the  
40 kind of investments that we're making in generation  
41 assets right now are not increasing the production from  
42 those assets. What they're doing is they're making sure  
43 that that production will continue, or that generation  
44 will continue, which is what we believe we're charged to  
45 do under the Heritage Contract.  
46

47 Although this is a very lengthy extract from the transcript, it highlights BCH's total lack of  
48 a common approach to the allocation of capital resources. It is simply not possible to  
49 meet the Energy Plan's requirement for comparability with a *"three bucket approach"*.  
50 Irrespective of the Energy Plan, it is imperative that BCH employs the same basic  
51 financial screen across all segments of the company in order to make the first  
52 assessment of where scarce capital resources should be spent. Once this initial  
53 determination is made, it is open to BCH management to exercise its business  
54 judgement in relation to allocating appropriate capital resources, provided it is done in a  
55 transparent and prudent manner.  
56

57 Appendix 2 is a table that compares some of BCH decisions and initiatives against the  
58 above extracts from the Energy Plan.

### 3. Integrated Electricity Plan (“IEP”)/ Resource and Expenditure and Acquisition Plan (“REAP”)

As part of the Review, BCH filed the IEP as a “contextual” document. For the practically minded IPPBC, this is an allusive idea. This document evaluates and recommends BCH’s supply/demand portfolio-for the next 20 years. Unless the BCUC decides otherwise, its content is not open for public scrutiny. However, the REAP, the direct two year appendage of the IEP, is subject to approval in respect of capital expenditures and action plans. It is a concise (12 pages) abbreviated work that merely sets out what BCH is asking for approval for in “lump sum” dollars and in broad categories of future plans.

If is impossible to undertake due diligence on this document without fully understanding and debating the material on which it is based i.e. the IEP.

The IPPBC recommends that the BCUC not approve any expenditures within the REAP until the IEP can be openly and fairly evaluated. This is necessary to allow for a more realistic evaluation of BCH’s energy/supply forecast leading to a more secure and reliable electricity supply option for BCH’s customers.

It must be noted that the BCTC filed its capital plan as a contextual document, and it has no objection to it being subject to a full public review by the BCUC.

### 4. Security and Reliability of Supply

The IPPBC’s concerns about the security and reliability of BCH’s electricity supply can be easily summarised. In the Test Period, BCH states that it will only need to acquire 400 GWh of electricity from IPPs. BCH’s annual requirements are in excess of 50,000 GWh. This is not even close to being a realistic estimate of what is needed.

Currently, BCH is importing approximately 10% of its energy requirements. There isn’t even a drought of the type that occurred in the early 1940’s or the late 1970’s and early 1980’s. According to page 3 of the letter dated February 18, 2004 written by the Honourable Richard Neufeld, Minister of Energy, which is attached to BCUC IR 116.4:

"The Province owns the DSBs which are being managed for the benefit of all British Columbians. The revenues from the sale of this valuable provincial-resource help support healthcare and other public services. In my letter of November 19, 2002, I explained the nature and value of the DSBs, and also indicated BC Hydro has access to the DSBs and can acquire them to meet domestic load as required, as was the case during the recent cold spell. Having access to this resource at the British Columbian-United States border allows BC Hydro to have more certainty in its planning assumptions about the dependable capacity that can be accessed through the interties."

1 BCH is importing energy, and has imported capacity to meet its domestic requirements.

2

3 There is nothing in the Application that indicates how BCH has secured access to the  
4 Columbia Treaty Downstream Benefits and how it *can "acquire them to meet domestic  
5 load as required"*. There is no evidence as to what the terms and conditions including  
6 price are. BCH has not explained whether this "access" and "uncertainty" is firm or  
7 conditional.

8

9 Assuming normal reservoir inflows, energy imports will have to continue beyond the  
10 Test Period. Whether it is the risk of the demand for electricity increasing beyond  
11 BCH's current forecast, drought, or plant and equipment inadequacies or failures,  
12 BCH's solution is always to import more energy. But without the security of firm  
13 contracts, or proving that the required amounts of energy can be delivered when  
14 needed to the borders of the BCTC transmission system at an affordable price, BCH's  
15 customers are at risk.

16

17 The required energy is somehow supposed to be available because of the magic of  
18 BCH's storage reservoirs. These reservoirs will make the job of meeting the demand  
19 for energy through domestic or imported generation simpler, but they aren't the solution  
20 to every requirement. The supply still has to be there at an affordable price. BCH has  
21 not demonstrated that the required amounts of imports will be there when needed. For  
22 instance, where is the evidence of firm transmission capacity in the United States?  
23 What happens if BCH/Powerex loses its Power Marketing Authorisation? What  
24 happens if BCH/Powerex is restricted from making energy purchases in the Alberta  
25 open market?

26

27 BCH is using short-term, non-firm, energy imports to meet long-term domestic demand.  
28 It is the equivalent to financing long-term financial obligations with no fixed term, short-  
29 term debt. BCH's strategy isn't even equivalent to meeting long-term financial  
30 obligations with fixed term variable rate debt. In this instance, the borrower is at least  
31 assured that the "supply" of debt is fixed, but not the price. BCH does not have security  
32 of supply or price.

33

34 Instead of meeting the above burden, the company claims that the required supply is  
35 always available from its Burrard Thermal plant ("*Burrard*") and the only reason that it is  
36 importing so much electricity is that it is a cheaper alternative to producing electricity at  
37 Burrard. As set out in more detail under the heading "*Burrard Thermal Generating  
38 Plant*" the evidence shows, it is old and inefficient.

39

40 Power Smart is BCH's other key alternative to increased imports. As described in more  
41 detail in Appendix 2, the basic financial screen for this program is fatally flawed. The  
42 load displacement portion of this program is a thinly disguised source of subsidized  
43 generation. BCH is spending money on Power Smart programs that should be held in  
44 abeyance pending the implementation of stepped rates.

45

1 Unless providence supplies an abundance of water to flow into BC Hydro's reservoirs  
 2 during the Test Period, BCH's energy supply is not secure or reliable. As indicated by  
 3 the requirement to import capacity last winter, the capacity situation is not much better.  
 4

5 In this argument, the IPPBC has assumed that any purchases that BCH makes from  
 6 Alcan or Cominco, other than the approximately 150 megawatts that Alcan sells to BCH  
 7 under a firm energy purchase agreement, fall under the heading of "*Market electricity*  
 8 *purchases*" as used in Schedule A-9 page 2-49 of the Application. If this assumption is  
 9 not correct, then the security and reliability of BCH's electricity supply is worse than the  
 10 IPPBC has calculated. Alcan's ability to freely sell electricity is currently the subject of  
 11 Court proceedings that have been initiated by the District of Kitimat.  
 12

### 13 **4.1 Burrard Thermal Generating Plant**

14 The basic facts about this plant are:  
 15

- 16 • it is old, unreliable and inefficient
- 17
- 18 • unless the price of natural gas falls significantly, the cost of producing  
 19 energy at this facility is very high, and will always be high in comparison to  
 20 a modern, efficient facility
- 21 • spare parts for it are not readily available - they have to be manufactured
- 22 • contrary to what BCH claims, it is not a "low mileage" facility.  
 23

24 In response to IPPBC IR 1.60.1 BCH provided *the "Facility Asset Plan Fiscal 2004/2005*  
 25 *Burrard Generating Station"*. On pages 11 - 12 there is a table that shows remaining life  
 26 for the following turbines:  
 27

28	Unit 02	10,000 hours
29	Unit 04	15,000 hours
30	Unit 05	15,000 hours
31	Unit 06	96,000 hours

32  
 33 There is no corresponding information for units 01 and 03. According to the Heritage  
 34 Contract review transcript Volume 5, page 961 "*G4, 5 and 6 are the newer units at the*  
 35 *plant.*" As indicated under the heading "*The Requirement to Manufacture Parts*" Unit 2  
 36 was subject to a major repair in 2000.  
 37

38 There are 8,760 hours in a year. For long term planning purposes BCH believes  
 39 Burrard can produce 6,000 GWh which is based on a capacity factor of 75%. This  
 40 reduces the annual hourly toll on all six units but the remaining life of Units 2, 4 and 5  
 41 doesn't increase much. Contrary to BCH's evidence, Burrard is not a "*low mileage*"  
 42 facility. Instead its is a facility with limited operating life remaining that needs more  
 43 money poured in to maintain its energy capability.

1  
2 In response to CEC IR 1.7.4.1, BCH provided a document *entitled "Overview of Burrard*  
3 *Generating Station, Presentation to the MLA Committee, Dawn Farrell - EVP*  
4 *Generation, BC Hydro October 8<sup>th</sup>, 2003" ("MLA Summary")*. On page 2 it states:

5  
6 "Further, Burrard is forecast to require capital expenditures of about \$95 million  
7 over the next 20 years, but a large portion of that is dependent on the forecast  
8 useage of the plant. Much of this capital will be required within the next five  
9 years due to the ageing of equipment and as a result raises the question of  
10 whether such expenditures are economically justifiable given the vintage and  
11 inefficiency of Burrard. Postponement of these expenditures may further  
12 degrade the assets."

13  
14 BCH spent approximately \$190 million on pollution control equipment which did not  
15 improve Burrard's efficiency. This expenditure did not deal with the high mileage  
16 problem. Spending another \$95 million will not deal with the efficiency problem and  
17 while it may temporarily deal with the high mileage problem in relation to those pieces of  
18 plant and machinery that are replaced, it will not deal with the old age of the plant and  
19 equipment that aren't replaced. A plant is only as reliable as its weakest link. If  
20 replacement or old parts fail, they will have to be manufactured.

21  
22 If will be extremely difficult for BCH to justify spending an additional \$95 million as it  
23 seeks to accelerate the depreciation rate for this plant.

#### 24 25 **4.1.1 Additional Burrard Information**

26  
27 The TR extracts set out below complete the picture about the true physical state of the  
28 plant, and BCH's desire to hang on to Burrard irrespective of the evidence.

##### 29 30 **4.1.1.1 What BCH said at the Heritage Contract Review**

31  
32 TR Volume 18, 3238-3241:

33  
34 MR. AUSTIN: Q: And this is from Volume 4 of the Heritage  
35 Contract transcript, and I'd like to draw your attention  
36 to the bottom of the first page and it says:

37 "Well, the Burrard capability has been  
38 estimated for long-term planning purposes at  
39 about 6,100 GWh or around 6,000 GWh, which is  
40 fairly close to the numbers in there although  
41 somewhat higher. There will be short-term  
42 estimates where that number may be derated for  
43 operational planning purposes."

44 And I'd like to draw your attention to Volume  
45 1 of B.C. Hydro's evidence, and that's page 5-4...

46  
47 MR. AUSTIN: Q: And I'd just like to read it out for  
48 those who don't have it readily available. It says:  
49 "B.C. Hydro's current short-term plan for  
50 Burrard Generating Station is to maintain  
51 three units in standby generation mode 4, 5  
52 and 6, and three units in VAR support mode 1,  
53 2 and 3. The three units available in standby

1 generation mode will be exercised on a regular  
2 basis to ensure availability and will be  
3 dispatched as needed to provide capacity and  
4 energy to the B.C. Hydro system. The steam  
5 turbines and boilers for the units in VAR  
6 support mode will be preserved in storage and  
7 will be recallable in generation mode on  
8 approximately six months' notice. This  
9 configuration will ensure that approximately  
10 450 megawatts of capacity and 3,300 GWh of  
11 energy capability will be available from  
12 Burrard Generating Station for the next  
13 several years. Full capability is preserved  
14 for resource planning purposes. In addition,  
15 the VAR support from units 1, 2 and 3 will be  
16 sufficient to meet voltage support  
17 requirements on the B.C. Hydro Transmission  
18 system."  
19

20 Q: The question I have for you, panel, is,  
21 what happened in the interval from the Heritage contract  
22 review, which was last summer, to the filing of the  
23 application, where on one hand you were looking at 6,000  
24 gWh and then all of a sudden it's down to 3,300 gWh?  
25

26 MR. SPAFFORD: A: The application reflects some decisions  
27 that were made within the Generation line of business.  
28 In response to the current forecasts that we saw of  
29 electricity and gas prices, whereby we saw that, based  
30 on the load resource balance, given to us from  
31 Distribution, that we did not expect to use Burrard to a  
32 great extent. Therefore we took some steps to reduce  
33 expenditures at the plant, in the very near term,  
34 minimize the capital expenditures to the greatest extent  
35 possible, reduce the operating staff to reduce the OMA,  
36 and to acquire -- and that was done on the basis that it  
37 was economic to acquire the energy that would otherwise  
38 have been produced at Burrard, it was economic to go out  
39 to the short-term electricity market to purchase that  
40 energy. So that is part of our function, in the sense  
41 that we take the resources that are given to us and we  
42 try to dispatch them in a way that optimizes or  
43 minimizes the total cost of that operation. So we could  
44 have chosen to run Burrard, and you would have seen  
45 several thousand gWh of generation at Burrard. If we  
46 wanted to do that, we could -- we would have had to  
47 spend a great deal more on sustaining capital and on  
48 operating staff at the plant. So instead, we took the  
49 more economic route, which was to minimize those  
50 expenditures, reduce staff, and as a result of that,  
51 what we are now seeing is that, for the very near term,  
52 for the next six months at least, we can only rely on  
53 that plant for 450 megawatts of capacity. However, it  
54 keeps all of our options open for the longer term to  
55 again rely on the plant for 900 megawatts or 6,000 gWh  
56 of energy.  
57

58 The IPPBC hasn't calculated how much VAR support Burrard could provide if BCH  
59 attempted to produce 6,000 GWh of energy from this plant.  
60  
61

#### 4.1.1.2 The Requirement to Manufacture Parts

TR Volume 19, pages 3258-3259:

Mr. Dunlop, yesterday I asked you whether parts were readily available for the Burrard thermal plant and you said that they have to be manufactured because they're not stock items. I was just wondering what the lead time is to have a part manufactured?

MR. DUNLOP: A: It very much depends on the part.

MR. AUSTIN: Q: And what's the longest lead time that it would generally -- that it would take to manufacture a part?

MR. DUNLOP: A: Probably the longest lead time would be for components of the steam turbine, and I would estimate, and it's just an estimate, that that could take up to 18 months for a replacement turbine to be manufactured. When the turbine failed on unit 2 at Burrard in early 2000, it was a failure of the stage turbine. There was considerable damage to the turbine as well as collateral damage to the generator. Replacing the turbine was not the only option. We were able to return the unit to service without replacing the turbine by working with the original equipment manufacturer to modify the turbine to get it back into service quickly.

MR. AUSTIN: Q: In relation to that repair, did you get any warranty for the manufacture with respect to that?

MR. DUNLOP: A: Not in terms of the repair.

#### 4.1.1.3 Record Production of 4,000 GWh

One of the more interesting items in Burrard's history is that record production occurred in 2001. A time when export prices in the U.S. market were at, or near record levels. One possible conclusion to be drawn is that with these prices, the plant would have been operated at maximum output.

TR Volume 19, page 3266:

MR. SPAFFORD: A: I guess I did want to add to Mrs. Farrell's initial response in that there have been periods of time through history where Burrard was utilized as largely an energy producer. So if you go back into the late '70s, Burrard was used as an energy producer at that time. Again in the late 1980s and through the early 1990s, Burrard was used as an energy producer. And as recently as 2001, we set a record production at that plant and had almost 4,000 GWh of generation at Burrard. A report that was prepared for the provincial government at that time indicated that in 2001, Burrard contributed about \$166 million to B.C. Hydro's bottom line.

1 So based on the prices of gas that we were  
 2 seeing as recently as 2001, Burrard was very much what  
 3 we call in the money. It was dispatched and provided a  
 4 profit to BC Hydro. But with the current gas prices,  
 5 we're seeing that picture turn around at this time.  
 6

#### 7 **4.1.1.4 Low Mileage Plant that will Produce 6,000 GWh**

8  
 9 Despite the evidence provided in response to BCUC 1.60.1, the *"Facility Asset Plan*  
 10 *Fiscal 2004/2005 Burrard Generating Station"*, BCH still insists Burrard is a *"low*  
 11 *mileage"* plant.  
 12

13 At TR Volume 19, page 3268:

14  
 15 MS. FARRELL: A: Given that Burrard hardly ever runs and  
 16 has very few operating hours on it, I think it's very  
 17 realistic. I think the key issue is, for Burrard, that  
 18 once you know that you're going to have to run it for  
 19 6,000 gigawatt hours a year you put it into service as  
 20 if it is a plant that's running that amount. You put  
 21 the capital program in place, you put the turn around  
 22 schedules in place, you put the operating orders in  
 23 place in order to get it to run at that level.

24 I would say the risk is really more along the  
 25 lines that as you're leading up to a time where you're  
 26 going to start to run -- where you thought you were to  
 27 start to run the plant at that level, you have to get  
 28 everything in place so that it actually can run in that  
 29 level.

30 What we're saying today is, from a -- so  
 31 we're saying technically that plant, based on personal  
 32 assessments, based on assessments of people who are  
 33 operators of thermal plants, based on our own operators,  
 34 based on our own engineering analysis, that plant, based  
 35 on its age, technically should be able to and can  
 36 operate at that level.

37 Currently that plant -- and in B.C. Hydro's  
 38 history that plant has never had to operate at that  
 39 level because it's never been required to operate at  
 40 that level. And I think that's the major difference  
 41 between the past levels that it's operated at and its  
 42 future potential.  
 43

#### 44 **4.1.1.5 Knowledge of Two Major Breakdowns**

45  
 46 Although the representative of BCH was prepared to offer the opinion immediately  
 47 above, it didn't know why there were two major failures at the plant in the last 5 years,  
 48 TR Volume 19, page 3269:

49  
 50 MS. FARRELL: A: I haven't personally gone into look in  
 51 detail at what those major failures were and why those  
 52 major failures occurred, so anything that I would say  
 53 would be very subjective at this point, but my overall,  
 54 broadest assessment is that Burrard is a thermal  
 55 facility and it lives in a hydro business.  
 56

1 The Burrard Thermal Plant is one high mileage 1957 Chevrolet that won't make it to  
 2 Calgary. It may be possible to use the plant for the purposes of providing capacity and  
 3 VAR support but not as a source of energy. Even its ability to provide capacity is  
 4 doubtful as evidenced by the following extracts from pages 1 and 2 of the MLA  
 5 Summary:

6  
 7 The time line required to bring Burrard units on-line is lengthy. Current maintenance  
 8 for Burrard supports the ability to start up generating units within periods ranging from  
 9 half a day to three days (barring force outages). By comparison, hydro units can  
 10 respond within minutes.

11  
 12 In addition, the limited liquidity of gas markets at Sumas, acquisition of sufficient gas  
 13 to fully dispatch Burrard would take several months. While firm gas transportation is  
 14 available, the firm gas commodity itself has not been contracted for, due to uncertain  
 15 requirements for the winter peaks and high cost of gas transportation upstream of  
 16 Sumas.

17  
 18 Anecdotally, Burrard is viewed by our power marketers as only being an energy plant,  
 19 as its capacity is generally unavailable due to the above limitations.  
 20

#### 21 **4.1.1.6 BCH Continues to Hang on to this Plant**

22  
 23 Despite the evidence that Burrard is old and unreliable, BCH continues to hang on to it.  
 24 At TR Volume 7, page 825 BCH does not see the plant as a long-term energy provider,  
 25 and yet the planners at BCH attribute 6,000 GWh of energy, and the ability for the aging  
 26 facility suddenly to spring to life after years of not being used.

27  
 28 MS. FARRELL: A: Yes, I think as part of thinking about  
 29 what would be in the deferral accounts for Burrard --  
 30 Burrard I think is a special case, and I just want to  
 31 take a minute to talk about that. We have set up  
 32 Burrard and we'll talk about it later in Panel 7, but we  
 33 look at Burrard as a plant that's really at the end of  
 34 its life just in terms of the efficiency that that plant  
 35 has for burning gas. So we don't see it as a plant that  
 36 really should, in the long term, be providing energy for  
 37 the system.  
 38

39 BCH's attitude and approach is disturbing. IPPs can provide energy at competitive  
 40 prices, bringing both availability and price security into the portfolio of supply for BCH,  
 41

42 TR Volume 20, pages 3563-3565:

43  
 44  
 45 COMMISSIONER BIRCH: What I'm trying to reconcile in my  
 46 mind is I've got on the one hand the arguments about the  
 47 level playing field on financial analysis. I've got the  
 48 arguments with respect to the depreciation rate on  
 49 Burrard and what's the appropriate rate. I hear you  
 50 saying, "Well, we've spent the 190 million so we'll  
 51 treat that as sunk cost, we'll just look at the  
 52 incremental costs going forward. Now is that consistent  
 53 with the playing field?" If it really is sunk cost,  
 54 then why isn't it written down? And there's different  
 55 ways to look at this, and that's what I'm trying to get

1 a balance on is how you're really looking at the  
2 financials of this plant, and is that in any way leading  
3 you to continue spending and spending, you know,  
4 throwing good money after bad, so to speak? That's what  
5 I was trying to get at.  
6

7 MS. FARRELL: A: No, I think it's the opposite. I think,  
8 I think by getting really clear on what the costs are of  
9 the various services that Burrard provides, and trying  
10 to get a real clear sense of, you know, what is the  
11 comparison for VAR support, is -- I mean, would you run  
12 a 900 megawatt rank and cycle gas fired plant to provide  
13 VARs in, you know, in the B.C. system for the long term,  
14 or would you actually go and build standard VAR  
15 compensator? So that's one comparison.

16 Would you continue to keep a plant staffed up  
17 just in case you needed to run it a couple of days a  
18 year for capacity, when you could potentially go to the  
19 border and buy that capacity for a different price?  
20 Would you continue to have the plant available for  
21 recall just in case you needed it to run energy next  
22 year because suddenly gas prices fell, and it was a dry  
23 water year and you just happened to be able to run  
24 Burrard all year.

25 So the kind of analysis that we're doing --  
26 the reason that we're -- I mean, I would love to be  
27 prepared with all of that for you here today, and we  
28 have some obligations to try to get that all done by the  
29 end of the summer. But the reason that we don't have it  
30 done is because we need to look at all those individual  
31 services that Burrard provides and look at all the costs  
32 associated with those, and then figure out what the best  
33 economic -- what the economic decision is. Then once  
34 we've got the best economic decision, there will be a  
35 ratepayer impact. You know, what is the ratepayer  
36 impact of that particular decision, and what is the  
37 financial -- and then what are the financial  
38 implications of that decision, in terms of, you know,  
39 what does it mean for the accounting decisions and the  
40 financing decisions.

41 So that's the analysis that we're trying to  
42 undertake right now.  
43

## 44 4.2 Power Smart

45  
46 The IPPBC directed a lot of its limited resources towards evaluating, analyzing, and  
47 commenting on BCH's Power Smart program. This in depth approach provided  
48 invaluable assistance in relation to how BCH does or doesn't apply financial screens  
49 and how it carries on its business in all areas of the organization. It formed the basis and  
50 framework upon which the IPPBC assessed all other areas of interest against.

51 The IPPBC's detailed, technical Power Smart argument is attached as Appendix 2.  
52 Although it is extensive, set out below are certain matters pertaining to Power Smart  
53 that the IPPBC wishes to draw particular attention to.  
54  
55  
56  
57

#### 1 4.2.1 Weyerhaeuser - Canfor

2  
3 BCH took the position that projects such as the Weyerhaeuser and Canfor load  
4 displacement projects could not be bid into competitive bidding process because their  
5 development was tied to other capital improvements at the relevant facility.  
6

7 This approach might have been convincing but for Exhibit C10-7, which clearly shows  
8 that the Weyerhaeuser and Canfor projects were previously bid into a BCH all source  
9 competitive acquisition process. The Canfor project made the short list but it did not  
10 proceed primarily because at the end of the evaluation process, BCH declared its  
11 Burrard Thermal rebuild option the "winner" even though it was never bid into the  
12 acquisition process. Ultimately the Provincial Government had to step in to sort out the  
13 problems created by this decision.  
14

15 The Weyerhaeuser and Canfor projects have a long history that is not consistent with  
16 any immediate need to complete them as indicated by the following extract,  
17

18 TR Volume 14, at pages 2259-2260:  
19

20 COMMISSIONER BIRCH: Okay. Thank you, I'll switch to the  
21 questioning from that for a moment then. Good morning,  
22 panel. Ms. Van Ruyven, on your testimony on Friday,  
23 Volume 12, page 1879, line 5 -- I don't know if you have  
24 to look it up but I just give it for the reference --  
25 you mentioned that Weyerhaeuser and Canfor projects were  
26 load displacement projects, and no formal bidding  
27 process was held. Is that true?  
28

29 MS. VAN RUYVEN: A: That is correct.  
30

31 COMMISSIONER BIRCH: Can you tell me how the process worked  
32 then?  
33

34 MS. VAN RUYVEN: A: It was a negotiated contract with  
35 each of those two individual customers, spanned for  
36 example Weyerhaeuser's case of approximately a year from  
37 the time the project was initiated and brought to B.C.  
38 Hydro. It was evaluated within our competitive process  
39 within PowerSmart, and certainly some parameters were  
40 clearly set. I believe Mr. Marchant talked about what  
41 those parameters were for moving forward with the  
42 projects, but they were negotiated individually with  
43 those two customers.  
44

45 MR. MARCHANT: A: Both customers did make incentive  
46 applications to B.C. Hydro as part of our six-week cutoff  
47 process, but it certainly wasn't a load displacement  
48 call.  
49

50 COMMISSIONER BIRCH: Why was there no competitive process  
51 followed, given that there was 13 wood waste projects in  
52 the '95 bid?  
53

54 MS. VAN RUYVEN: A: Well, we had a number of wood waste  
55 projects bid into the customer based generation call as  
56 well as into our green call, and a few of those have

1 been successful. We were unaware of any other wood  
2 waste projects that were either -- hadn't bid into a  
3 recent call or were looking for load displacement. We  
4 are aware of some other projects that are out there and  
5 could either bid into an IPP call or could be considered  
6 for a load displacement program as well.  
7

8 Additional information about the long history of these projects can be found at  
9

10 TR Volume 14, page 2261:  
11

12 COMMISSIONER BIRCH: Mr. Marchant, you testified yesterday,  
13 Volume 13, page 2060, line 3, that Canfor and  
14 Weyerhaeuser projects were not the same as the projects  
15 the two companies bid in '95 with Mr. Gathercole's  
16 evidence at C10-7. Looking at those two, the Canfor  
17 project that was bid in '95 was a wood waste project in  
18 Prince George of 320 gigawatt hours and was 41  
19 megawatts. The project you accepted was a wood waste  
20 project in Prince George of 390 gigawatt hours and 48  
21 megawatts. They sound very similar. What was the  
22 difference?  
23

24 MR. MARCHANT: The requirement for Canfor for load  
25 displacement was developed with them, as we talked to  
26 them, they had an inkling or an idea when they came  
27 forward of the size and magnitude of the project they  
28 wanted to do. We then worked with them to assess what  
29 incentive we might provide that would best optimize  
30 their requirement at the site, and the incentive that we  
31 were able to afford. I'm not trying to tell you that  
32 over a period of time, Canfor haven't been interested in  
33 having on-site hog-fuel generation. I just can tell you  
34 that the players involved and the project itself had a  
35 genesis in the discussions that led to the load  
36 displacement acquisition.  
37

38 As an example, the project you're speaking of  
39 from the past was actually on a different -- there's two  
40 mills at the site. It was on the other mill site. It  
41 was going to use -- be attached to it for different  
42 steam purposes and such, so we're actually on the other  
43 mill site. So again, I'm not trying to lead you to  
44 believe that they haven't had an interest in on-site  
45 self-generation burning hog fuel. But it's a project  
46 that didn't have a genesis with the load displacement.

47 The Canfor and Weyerhaeuser projects received substantial incentives from all of  
48 BCH's other customers which will essentially insulate Canfor and Weyerhaeuser from  
49 future increases in the price of electricity,  
50

51 TR Volume 14 pages 2262-2267:  
52

53 COMMISSIONER BIRCH: Q: So they were not seeking an  
54 incentive in '95 when they bid that project.  
55

56 MS. VAN RUYVEN: A: No, they would have been seeking an  
57 electricity purchase agreement with B.C. Hydro, which  
58 would be purchasing on the long-term output -- the  
59 output.

1  
2  
3 MR. MARCHANT: The barrier the industrials are facing that  
4 we seem to be meeting with load displacement is the  
5 capital barrier. They don't seem to have any issues,  
6 they're not seeking an energy purchase agreement.  
7 They're looking for the capital up front.

8  
9 COMMISSIONER BIRCH: Q: Could any of the other projects  
10 bid in '95 go ahead without an incentive of this  
11 magnitude?

12 MR. MARCHANT: A: On their own?

13  
14 MS. VAN RUYVEN: A: Well, just glancing at that list in  
15 1995, several of those projects have been successful in  
16 bids that we've had since 1995. So when we looked at  
17 that list, a lot of them we recognize as independent  
18 power producers that we have actually signed electricity  
19 purchase agreements with. None of them have gone  
20 forward as load displacement, as a project that existed  
21 in '95, that we're aware of. As we said, the  
22 Weyerhaeuser and Canfor projects, we feel, look much  
23 different.  
24

25 COMMISSIONER BIRCH: Q: Maybe I should ask the question in  
26 a different way. If you were willing to provide 40  
27 percent of the capital cost, there's a lot of projects  
28 that might fly. I guess my question is, how did you  
29 determine that 49 million dollars was the right  
30 incentive to get them to do it, as opposed to 45  
31 million, or 40 million, or some other number?  
32

33 MR. MARCHANT: A: A couple of things would have driven  
34 that. First of all, we're using from the other  
35 competitive calls we've had for incentive programs in  
36 the industrial area, what cent-per-kilowatt-hour might  
37 we be offering for an industrial project. And our --  
38 just let me get it for you -- for large industrials,  
39 we've provided without GST incentives between 0.6 cents  
40 per kilowatt-hour, and one-and-a-half cents per  
41 kilowatt-hour. So we established a cap, per se, of oneand-  
42 a-half cents per kilowatt-hour. Sorry, that  
43 includes GST. Sorry, I should back that up, so let's  
44 call it 1.4-something. 1.4 cents per kilowatt-hour for  
45 load displacement. We felt that would be a solid  
46 investment in the industrial sector, contributing  
47 towards the whole industrial portfolio. The other limit  
48 that we put in play that we insisted, as I was  
49 mentioning the other day, that we look at Canfor and  
50 Weyerhaeuser's calculation spreadsheet of their internal  
51 rate of return on the project. And we put a cap on the  
52 internal rate of return for them that we wouldn't  
53 exceed, or we wouldn't offer an incentive that exceeded  
54 that rate of return.  
55

56 COMMISSIONER BIRCH: Q: Your press release at the time  
57 stated that the resulting power was generated for oneand-  
58 a-half cents a kilowatt. That seems rather low.  
59 Would they not have done it for two, or for two-and-a-half?  
60

61 MR. MARCHANT: A: The one-and-a-half cents is referring to

1 our incentive. I agree with you that that's what the  
2 press release says -- I'm just, I think it should be  
3 clarified that that's not the cost of generation of the  
4 electricity. The one and a half cents per kilowatt hour  
5 was the media's press release of the levelized cost of  
6 the incentive provided by B.C. Hydro, with GST.  
7

8 Some of these incentives are not easily identifiable, such as backup electricity.  
9

10 COMMISSIONER BIRCH: Do you provide black start capability  
11 for them?  
12

13 MR. MARCHANT: A: They maintain their status as an 1821  
14 customer. They significantly reduced their contract  
15 with us, but they at their lower level still have access  
16 to black start. They would still have access to energy  
17 if available as well, if they had a failure of the  
18 generator, but it would be if available.  
19

20 COMMISSIONER BIRCH: So do they pay for that service?  
21

22 MR. MARCHANT: A: They do in that --  
23

24 COMMISSIONER BIRCH: At the lower level.  
25

26 MR. MARCHANT: A: Yes, yes, yes. And then obviously if  
27 energy was available to them, they would purchase it.  
28 But we have no requirement to have energy available for  
29 them above the ESA.  
30

31 COMMISSIONER BIRCH: Given that they have transmission  
32 lines capable of serving at the higher level, I assume  
33 there'd be no real reason why you wouldn't be able to  
34 serve them that. I mean theoretically there's some day  
35 when you couldn't provide energy generation, but I would  
36 have thought in the market you could get the power if  
37 they had a transmission line big enough to serve them.  
38

39 MR. MARCHANT: A: I guess the difference then again would  
40 be there's no obligation on us. If we were -- I  
41 shouldn't get into Ms. Hemmingsen's area, but if we were  
42 forced to go to a market purchase to serve them, I  
43 presume we wouldn't do that if it was at the tariff.  
44

45 COMMISSIONER BIRCH: I'm just trying to get a feel for the  
46 level of incentives. You provided \$49 million of  
47 capital up front, which is about 40 percent of the  
48 project. You're effectively giving them backup  
49 capability, and I assume that there was wheeling between  
50 the mills.  
51

52 MR. MARCHANT: A: The two mills at Prince George are  
53 considered one account.  
54

55 COMMISSIONER BIRCH: One account, okay.  
56

57 MR. MARCHANT: A: Yeah.  
58

59 COMMISSIONER BIRCH: I'm just curious as to sort of all the  
60 different incentives they were given, given that there  
61 were so many other projects that were bid at the time.

1  
2 MR. MARCHANT: A: Yeah. I'm not sure I would agree that  
3 they have access to back up power. Perhaps today they  
4 would, the contracts for 15 years. I'm not sure what  
5 growth we'll face on the system, but I do know we have  
6 no obligation to provide them with electricity.  
7

8 COMMISSIONER BIRCH: Okay. So in other words it's like --  
9 instead of being firm it's interruptible.  
10

11 MR. MARCHANT: A: Pardon me?  
12

13 COMMISSIONER BIRCH: Instead of being firm it's  
14 interruptible effectively with a high probability of  
15 service.  
16

17 MR. MARCHANT: A: I would agree other than that I don't  
18 know how high the probability is as we move out over the  
19 15-year period.  
20

21 As extracted from TR Vol 14, pages 2267-2269, the planning for the Weyerhaeuser  
22 project may have been well advanced before BCH offered financial incentives and  
23 material in the form of a press release, that was made public, may not be completely  
24 accurate:  
25

26 COMMISSIONER BIRCH: Right.  
27 You testified yesterday that Weyerhaeuser  
28 already had a turbo generator sized appropriately for  
29 the project in Prince George in inventory within their  
30 overall organization. What due diligence did you do to  
31 conduct -- to verify the veracity of that statement?  
32

33 MR. MARCHANT: A: We spoke with them within the company,  
34 just look at what other sites they were considering  
35 putting the generator at, and I can tell you with great  
36 assurance that the generator without our incentive would  
37 have gone to another location within -- in the United  
38 States. So they were considering placing the unit at  
39 one of several mills.  
40

41 COMMISSIONER BIRCH: What I guess I'm trying to get at is  
42 the governance procedure you used to negotiate the  
43 project to know that you in essence didn't pass across  
44 to the other side, whoever you're negotiating with, more  
45 effectively than some of the parameters you've set out.  
46

47 MR. MARCHANT: A: And as you say, the parameters that  
48 I've set out, the key ones that we used for the cap on  
49 the price, which we didn't provide to them, the one and  
50 a half cents, and the cap on the IRR which they came  
51 below. So those are the only solid facts I can put in  
52 front of you beyond that it was our requirement to see  
53 the alternatives they were looking at, to demonstrate to  
54 us that there indeed were alternatives.  
55

56 COMMISSIONER BIRCH: Q: I can distribute the press release  
57 if you'd like, to put it on the record. It just says  
58 Canfor's project will generate 390 gigawatts costing  
59 one-and-a-half cents a kilowatt. Could you just run  
60 that by me again as to why that's not quite accurate?  
61

1 MR. MARCHANT: A: Well, the one-and-a-half cent per  
2 kilowatt-hour, again, is a rounded representation of the  
3 incentive that we've provided. So we're providing them  
4 in that payment stream I've described, 49 million  
5 dollars to get 390 gigawatt-hours per year for 15 years.  
6 If we levelized that incentive, it comes back without  
7 GST to 1.4-something cents per kilowatt-hour. We would  
8 have to add to that the cost of the hog fuel, or the  
9 transportation of the hog fuel. And that would produce  
10 the total resource cost, looking at both Weyerhaeuser or  
11 Canfor's costs of actually operating the unit at the  
12 site, as well as the incentive that we've provided.

13  
14 COMMISSIONER BIRCH: Q: Okay, so that's not the cost of  
15 the generation, it's the cost of your incentive. To  
16 you.

17 Mr. Marchant: A; To – to – Yes.

18  
19  
20 Additional material at TR Volume 13 pages 2169 - 2171 confirms the advanced nature  
21 of the planning for the Weyerhaeuser project:

22  
23 MR. FULTON: Q: And can you tell me whether Weyerhaeuser  
24 had purchased a portion of the equipment used in their  
25 project prior to the -- its enrollment in the PowerSmart  
26 program?

27  
28 MR. MARCHANT: A: The Corporation as a whole of  
29 Weyerhaeuser, which is a multi-national, had at its --  
30 in its inventory, a turbine. That turbine was being  
31 considered for placement in different jurisdictions  
32 around North America. So it's definitely true that the  
33 Weyerhaeuser Kamloops site did not have any equipment  
34 purchased, allocated or assigned to it.

35  
36 MR. FULTON: Q: So do I take it then that because the  
37 Weyerhaeuser Kamloops site did not have the equipment in  
38 its inventory, B.C. Hydro determined that it would not  
39 be disqualified from participation in the industrial  
40 PowerSmart program?

41  
42 MR. MARCHANT: A: It was very clear to us through our  
43 discussions with Weyerhaeuser that they were in  
44 competition within their own company for the use of that  
45 turbine. So they weren't disqualified in any way. We  
46 most certainly wouldn't incent a project where equipment  
47 had already been purchased or committed to for that  
48 site. That would obviously be a free rider.

49  
50 MR. FULTON: Q: I'm sorry, I didn't catch the end of your  
51 Answer

52  
53 MR. MARCHANT: A: That would obviously be a free rider.

54  
55 MR. FULTON: Q: Right, and so that, I take it, type of a  
56 -- or that position is a position, can I take it, that's  
57 encompassed in the third bullet of the response to  
58 Citizens for Public Power IR No. 1 C8.0 which is in  
59 Exhibit B1-11? So Citizens for Public Power, IR No. 1  
60 C8.0, Exhibit B1-11.  
61 for Public Power, IR No. 1

1 C8.0, Exhibit B1-11.

2  
3 MR. MARCHANT: A: That's correct.

4  
5 MR. FULTON: Q: Okay. So to Hydro's knowledge then,  
6 Weyerhaeuser hadn't started to purchase the equipment or  
7 done any of those things that might result in a  
8 rejection of its project.

9  
10 MR. MARCHANT: A: Right, and again the turbine was owned  
11 by Weyerhaeuser multinational but not allocated to this  
12 site.

13  
14 BCH claims the Canfor project it provided financial assistance to is different than the  
15 one, which was bid in 1995. Although the projects aren't identical, the common  
16 denominators are the use of woodwaste at a Canfor owned pulp mill in Prince George.

17  
18 The IPPBC is not suggesting that any changes be made to the contracts that BCH has  
19 entered into with Canfor and Weyerhaeuser. Instead, the IPPBC suggests that the  
20 BCUC direct BCH to dismantle its Power Smart Load Displacement Projects/Customer  
21 Self Generation Project and that all generating projects be the subject of an all source,  
22 level playing field bidding process. The exceptions to this are Resource Smart projects  
23 and under 5 megawatts generating projects. The former are discussed in more detail  
24 under "*Resource Smart*" and the later are too small to absorb the added costs of an  
25 extensive competitive bidding process.

26  
27 As per Exhibit C4-8, the Minister of Energy has requested BC Hydro to consider the all  
28 source competitive bid approach.

### 29 **4.3 BCH's Heritage Contract Position on Loosing Industrial Customer Load**

30  
31 On page 43 of the BCUC's "*Report and Recommendations*" regarding "*An Inquiry into a*  
32 "*Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation*  
33 "*Resources and Regarding Stepped Rates and Transmission Access*" dated October 17,  
34 2003 ("*Heritage Contract Recommendations*") it states:

35  
36 "BC Hydro proposes that Tier 1 consumption should be initially set at 90 percent of the CBL of  
37 industrial customers, with Tier 2 consumption set at 10 percent of CBL. BC Hydro believes that this  
38 Tier 1/Tier 2 Split "*strikes the correct balance between volume risk for BC Hydro and customer*  
39 "*opportunity*" (Ex. 8-2, p.7). BC Hydro notes that a very small percentage of energy available at the  
40 Tier 2 rate (for example, 2 percent of CBL) would not provide a significant increase in the incentive  
41 for customers to invest in energy efficiency or alternative supply, as compared to the existing 1821  
42 rate. Conversely, BC Hydro contends that significantly increasing the amount of Tier 2 energy  
43 beyond 10 percent of CBL at this time would result in an unacceptable risk of cost-shifting as the  
44 amount of customer load reductions increase."

45 In the Heritage Contract proceedings, BCH took the position that it didn't want to loose  
46 industrial customer load. For the purposes of Power Smart, it is paying the same  
47 customers to reduce their load. This makes absolutely no sense.

48  
49  
50

1 **4.4 Stepped Rates**

2  
3 BCH has ignored the following BCUC recommendation as accepted by the Minister of  
4 Energy as per Exhibit C4-7.

5

16	That BC Hydro's targeted PowerSmart and Customer Based Generation programs should be continued at funding levels justified on the basis of the Tier 2 rate, and that the programs be reviewed with the changes required for retail access for large power consumers.	Accepted, no Government direction necessary
----	--	---

6  
7 During cross examination this extract was put to BC Hydro witnesses. BCH's response:

8  
9 TR Volume 6, page 636:

10  
11 MR. AUSTIN: Q: So in your view when the BCUC  
12 recommendation says, should be continued at funding  
13 levels justified on the basis of the Tier 2 rate and  
14 B.C. Hydro answers, none of the program spending  
15 contained in the PowerSmart 10-year plan base case  
16 reflects the introduction of stepped rates, that's  
17 consistent?

18  
19 MS. VAN RUYVEN: A: Yes. We've said that for the  
20 purposes of the filing we did not make adjustments, but  
21 we absolutely accept the government direction that we  
22 will make those adjustments when the stepped rate design  
23 is completed and it's implemented.

24  
25 MR. AUSTIN: Q: So in the meantime you just carry on as  
26 before?

27  
28 MS. VAN RUYVEN: A: That's correct, because we've said  
29 the principle and the mechanism for going forward to  
30 make sure that people don't get paid twice, whether it's  
31 an incentive or in the Tier 2 pricing, so that will be a  
32 principle going into rate design, that we'll ensure that  
33 we're not paying twice for the same kilowatt hour.

34  
35  
36 Even when a direction regarding Power Smart is clear and unambiguous, BCH has  
37 difficulty understanding and complying with it.

38  
39 The IPPBC appreciates that the BCUC has previously made recommendations with  
40 respect to the inherent trade-offs concerning BCH's Power Smart Program as  
41 evidenced by the following extract from pages 70 and 71 of the Heritage Contract  
42 Recommendations:

43  
44 "The Commission Panel accepts the arguments of the JIESC that targeted  
45 programs such as PowerSmart and CBG should continue, but recognizes such  
46 programs diminish the load available for IPPs. However Policy Action #20  
47 directs electricity distributors to pursue clean energy, including efficiency  
48 improvements at existing facilities and cogeneration. Policy Action #23  
49 (removing a disincentive for energy distributors to invest in conservation and

1 energy efficiency) is consistent with utility investment in and expansion of  
 2 programs such as Power Smart.  
 3

4 The Commission Panel concludes that such programs should be allowed where  
 5 a benefit to the ratepayers can be clearly demonstrated, or where the programs  
 6 are aimed at saving or generating specific quantities of power in order to meet  
 7 Clean Electricity targets. To balance the concerns of the IPP community and the  
 8 goals of the Energy Plan, the Commission Panel believes that defined limits  
 9 should be created for financing programs such as Power Smart and CBG. The  
 10 Commission Panel does not believe it is appropriate for it to make  
 11 recommendations on the IPPBC requests that entities such as CPC, CBTE and  
 12 Powerex be restrained from competing for Tier 2 industrial demand."  
 13

14 Clearly there is a major misunderstanding between the BCUC's intentions and BCH's  
 15 actions, e.g. the financing of the Canfor and Weyerhaeuser projects. Wherever  
 16 possible, the solution must be a more open, competitive, level playing field bidding  
 17 between all sources of supply and demand.  
 18

#### 19 **4.5 Resource Smart - Site C - Revelstoke - Mica**

20  
 21 The IPPBC's preference is that all BCH's Resource Smart projects be bid into all source  
 22 competitive bidding processes. However, the IPPBC agrees that an exception should be  
 23 made for Resource Smart Projects that are the subject to BCUC review because they  
 24 require a Certificate for Public Convenience and Necessity provided that:  
 25

- 26 • all data, including financial data and models, is made publicly available
- 27 • the relevant project successfully passes through a suitable financial  
 28 screen before any development dollars, other than those that are  
 29 absolutely required to develop the inputs to the screen, are spent on it.  
 30 It must include all costs such as interest during construction, corporate  
 31 overheads, the cost of delivering the electricity to the Lower Mainland,  
 32 water rentals etc. The financial screen must be continually updated  
 33 and reapplied as the development process proceeds. The screen,  
 34 any updates and any application of it must be publicly available upon  
 35 request in electronic form.

36 The above would go part way to addressing the IPPBC's concerns about *the "level*  
 37 *playing field"* between IPP and BCH initiated generating projects and the momentum  
 38 that builds behind these BCH projects. Incidentally, the cost of any misguided  
 39 momentum is recovered from BCH's customers.  
 40

41 Despite repeated and detailed requests during cross e.g. TR Volume 12, pages 1846-  
 42 1848 and Volume 19, pages 3284 - 3298, the IPPBC was not able to obtain the financial  
 43 screen, or the results from its application, for BCH's proposed Site C, Revelstoke and  
 44 Mica projects. All it received was the information in Exhibits B1-91 and Exhibit B-190.  
 45

46 The IPPBC has concluded that the requested information doesn't exist or that BCH is  
 47 refusing to provide it. It therefore suggests that the BCUC not approve any of the  
 48 requested expenditures for these projects during the Test Period until BCH publicly

1 makes available the financial model/screen and the results of its application for BCH's  
2 proposed Site C, Revelstoke and Mica projects.

3  
4 It should be noted that in Exhibit C4-9, an extract from BCH's 1995 Integrated Electricity  
5 Plan, that the "*Corporate unit cost of energy at LM*" is 5.5 1994 cents/kWh. The  
6 "*Economic unit cost of firm energy at LM*" is 4.9 1994 cents/KWh. The corresponding  
7 information for "*Small and Medium Hydroelectric*" is "*Corporate*" 2.8 - 5 1994 cents/kWh  
8 and "*Economic*" 2.2 - 4.4.

9  
10 In Exhibit B1-24, the Site C material from BCH's 2004, Integrated Electricity Plan, the  
11 "*Unit Energy Cost (\$/MWh)*" is \$54. This document also states:

12  
13 "Unit energy costs above were estimated using conservative assumptions including short  
14 ammortization period. This approach is consistent with other projects in the database. MAPA and  
15 portfolio evaluation financing assumptions, including a 70 year ammortization period, lead to a unit  
16 energy cost estimate of \$36/MWh...

17  
18 The unit energy cost for this project is estimated to range from \$48/MWh to \$64/MWh, based on  
19 the price uncertainty ranking. The unit energy cost estimate for \$54/MWh was estimated using the  
20 spreadsheet-based model for resource options, with specific financial assumptions for a large  
21 project..."

22  
23 It is not possible to comprehend how BCH's Site C unit cost, however calculated, can  
24 remain relatively constant since 1995 yet IPP actual small and medium costs have gone  
25 up significantly since this date. As evidenced by the results from BCH's 2003 Green  
26 Energy competitive bid process, these actual cost are about \$51 per MWh.

27  
28 It also not possible to comprehend how despite repeated and detailed requests, BCH  
29 did not produce a "*spreadsheet-based*" model for it proposed Site C, Revelstoke and  
30 Mica projects.

31  
32 The IPPBC also suggests that the BCUC require BC Hydro to contact BCTC in order to  
33 obtain a basic understanding of the costs required to transmit the electricity from these  
34 projects to BCH Hydro load centre (TR 2992 - 2993.). For example in response to  
35 IPPBC IR 1.7.2, BCH attached "*T&D Business Case, McLeese 1&2 Capacitor Bank  
36 Refurbishment*" which contains the following on page 1:

37  
38 "... The reports substantiate that, without new transmission lines, T&D upgrades  
39 can only provide 500 MW of incremental export capability on the BCHA x BPAT  
40 path. Transmission reinforcements required to provide this additional 500 MW  
41 increase are:

42  
43 series compensation of %L87 (Guichon)

44  
45 refurbishment of McLeese capacitor banks 1 and 2 (to allow maximum Peace  
46 generation)

47  
48 installation of switchable shunt capacitors in the Lower Mainland.

49  
50 T&D is studying if the remaining 500 MW of capability (to meet the 1000 MW  
51 request) can be provided with additional reinforcements (not including new  
52 transmission lines). The study is expected to be complete by 02 Mar 2002."  
53

1  
2 In response to BCUC IR 2.118.3 BCH, provided a copy of "*A Briefing on BC Hydro's*  
3 *Transmission Capacity Requirement*" which was prepared by BC Hydro Executive  
4 Operations and is dated September 2002. At page 7 it states:

5  
6 "Further reinforcement of the westside intertie would ultimately require an  
7 additional 500 kV transmission line from Nicola Substation (near Kamloops to the  
8 Lower Mainland (possibly the Abbotsford area) which is about 200 km. This line  
9 would also be useful for supplying increasing demand in the Lower Mainland.  
10 The additional 500 kV transmission line from the Lower Mainland to the BC/US  
11 border, connected to a line in the U.S. would be beneficial for trade during the  
12 high value summer peak periods and would increase our import capability as  
13 long as a new corridor was used part-way through Washington.

14  
15 Westside reinforcement will be complicated by the limited right of way in the  
16 Lower Mainland and may require removal of existing lines to build higher  
17 capacity 500 kV lines. In addition, ongoing experience with US westside capacity  
18 restrictions makes it clear that close coordination is necessary between BC  
19 upgrades and complimentary investment in the U.S.

20  
21 The proposed Site C project on the Peace River would potentially be served with  
22 existing transmission reinforcement north of Kamloops, already completed in part  
23 to serve the formerly planned Kemano Completion Project. The Westside Intertie  
24 reinforcement from the south interior to the Lower Mainland would also be  
25 required to support Site C."

26  
27 It is clear that the availability and cost of transmission are going to be very significant  
28 issues for the Site C, Revelstoke and Mica projects and that a preliminary assessment  
29 of them must be made for the purposes of the corresponding financial screens.  
30

## 31 **5. Reservoir Levels and Inflows**

32

33 The evidence that BCH gave about its use of the drought sequence in the late 1970's  
34 vs. the drought sequence in the early 1940's was excellent. It is absolutely essential  
35 that all parties in the Review, including all segments of BC Hydro, understand the  
36 weather related risks associated with the design, construction, operation and  
37 management of BCH's predominantly hydroelectric generation system. The same  
38 applies to the BCTC transmission system that connects these remote sources of  
39 generation to the load centers.

40  
41 There is a tendency to forget about these weather related risks. They have, and will  
42 continue to adversely affect the security and reliability of the electricity that BCH  
43 provides to its customers.

44  
45 The droughts of the 1920's, 1940's and late 1970's and early 1980's may not be the  
46 worst that have been experienced in B.C. They may never occur again and the only  
47 thing certain about a drought is that no one knows whether there is one until it is  
48 finished. A cautious and conservative approach is required when considering how  
49 much electricity can be produced and delivered from BCH's hydro based generation.

50 In response to IPPBC IR 1.55.4 BCH wrote:  
51

1 "In general any reduction in system inflow below the average value will be  
 2 mitigated partly by an additional storage draft and partly by increased market  
 3 purchases. System reservoir levels are currently fairly low and are projected to  
 4 remain fairly low throughout F2005 and F2006. This diminishes the ability of  
 5 system storage to participate in mitigation of low inflows. Therefore, while there  
 6 may be some additional draft of system storage, additional market purchases will  
 7 provide the primary mitigation for low inflows.

8  
 9 Conversely, any increase in system inflows above the average value will result in  
 10 a combination of increased storage refill and reduced market purchases.  
 11 Currently, with low system storage levels, it is expected that higher-than-average  
 12 inflows would be used primarily to refill system storage, with a smaller impact on  
 13 market purchases."

14  
 15 According to BCH's response to IPPBC IR 1.80.3 inflows into the GMS and Mica  
 16 reservoirs as a % of 1971 - 2000 normal inflow were:  
 17

	GMS	Mica
2000	97%	98%
2001	109%	80%
2002	120%	99%
2003	98%	90%

18  
 19 By contrast in the drought period in the late 1970's and early 1980's the inflows were:  
 20

	GMS	Mica
1978	71%	97%
1979	96%	94%
1980	72%	93%
1981	110%	106%

21  
 22 These are the key reservoirs in the BCH system and support about 80% of BCH hydro -  
 23 electric generation. They are so large they are operated on a multi-year and not an  
 24 annual cycle. It is the inflows over a series of years that are important, and not those  
 25 that may occur in any single year. According to BCH's evidence TR Volume 19, pages  
 26 3301-3302:  
 27

28 MR. SPAFFORD: A: So if you look at that period during  
 29 the forties, aggregate system inflow was about --  
 30 actually, the number was 82 percent of average for that  
 31 three-year period of time. If you look at the -- during  
 32 the historic period of record there were several sets of  
 33 low flow sequences. There was a period back in the  
 34 1920s, actually, '28 to '32. There was a period from  
 35 '42 to '46, and there was another period from '77  
 36 through 1980, all of which produce about the same amount  
 37 of energy. The period through -- from 1978 through 1980,  
 38 which again is a three and a half year period, produced  
 39 had inflow, system inflows about 86 percent of  
 40 average, on average through that period of time. So the  
 41 lowest flow period that we consider in our operational  
 42 planning studies is the period from 1978 through 1980...  
 43

1 Despite near average inflows over the past 3 years, BCH reservoir levels are currently  
2 fairly low. This translates into estimated imports of approximately 6,153 GWh in fiscal  
3 2005 and 4,406 in fiscal 2006. According to the TR Volume 19, page 3311:

4  
5 MR. SPAFFORD: A: The only other thing I would add is  
6 that what we're seeing today, as I mentioned, is about  
7 89 percent of average. That is actually not as bad as  
8 those critical sequences when we saw flows in the range  
9 of 83 to 86 percent of average.

10  
11 As flows decline, imports increase,

12  
13 TR Volume 19, pages 3334 - 3336:

14  
15 MR. WEAFFER: Q: To the extent water inflows are low in a  
16 given year, it is possible to establish a deferral  
17 account to set those off against normal inflow years, is  
18 that correct?

19  
20 MR. SPAFFORD: A: Yes, and in fact our proposal is that  
21 we do exactly that. We would come up with our best  
22 estimate of the forecast cost of energy as of the date  
23 of our application, which we did. That is the  
24 evidentiary update. That was our best forecast. We  
25 now, as I said, based on the most recent studies, expect  
26 the cost of energy in fiscal 2005 to be probably in the  
27 order of 70 to 90 million dollars higher than the  
28 forecasts that we made in the evidentiary update, and we  
29 would see the difference between those would flow into  
30 the deferral accounts.

31  
32 MR. WEAFFER: Q: That's an incremental addition. The 90  
33 million is the total adjustment from the original  
34 filing. It's not an addition from –

35  
36 MR. SPAFFORD: A: The 90 million is the adjustment from  
37 the evidentiary update.

38  
39 MR. WEAFFER: Q: Which included 70 million from the  
40 original filing, approximately.

41  
42 MR. SPAFFORD: A: There was -- the original -- the  
43 evidentiary update was several million, I don't know the  
44 precise number, but it was -- I don't know if Mr. Morris  
45 has it.

46  
47 MR. MORRIS: A: Yes, the evidentiary update had a change  
48 of approximately 77 million from the December  
49 application that was based on normal water inflows for  
50 the fiscal 2005, and the evidentiary update, the latest  
51 forecast was approximately 94 percent and now it's  
52 approximately 89 percent.

53  
54 MR. WEAFFER: Q: So we're approximately 190 million on  
55 top -- we've increased from the original filing by  
56 approximately \$167 million?

57  
58 MR. MORRIS: A: Approximately, yes.

59  
60 MR. WEAFFER: Q: Does B.C. Hydro see that as a fairly

1 high level of volatility?

2  
3 MR. MORRIS: A: No, I think that's well within the  
4 volatility that we've discussed in a number of the  
5 information requests.

6  
7 MR. SPAFFORD: A: And I think in the Heritage Contract we  
8 indicated that the volatility associated with the cost  
9 of energy can easily be in the plus or minus \$300  
10 million range.

11  
12 MR. WEAFFER: Q: And we've seen \$162 million swing in  
13 five months. So we're --

14  
15 MR. SPAFFORD: A: Yes, so --

16  
17 MR. WEAFFER: Q: -- path we're going to exceed 300  
18 million by the fiscal year --

19  
20 According to the BCH evidence,

21  
22 TR Volume 19, page 3441:

23  
24 MR. FULTON: Q: Okay. Well, perhaps I could ask you in  
25 view of your answer, Mr. Spafford, if you could provide  
26 impacts at both 400 and 800 gigawatt hours.

27  
28 MR. SPAFFORD: A: Well, again, I think I'm just going to  
29 use a rough number of \$70 a megawatt hour Canadian for  
30 those purchases, based on the market prices that we're  
31 seeing today. And so 400 would translate into 28, or  
32 say 30 million dollars, and 800 is going to translate  
33 into 56, or in round numbers, \$60 million.

34  
35  
36 If a drought similar to the one in the late 1970's and early  
37 1980's occurs, then the requirement for imports will increase  
38 further. With the further possibility that the Williston  
39 reservoir will go below the 2,150 foot elevation.

40  
41 TR volume 19, pages 3306 - 3307:

42  
43 MR. AUSTIN: Q: And in the IPPBC's Information Requests  
44 we were trying to understand what the impact of running  
45 that model would be on reservoir levels in the next two  
46 years, and the question I have for you, assuming you ran  
47 your new version of the model and assuming you had the  
48 same type of inflows that you had in the late seventies  
49 and early eighties, would the Williston Reservoir be  
50 drawn down below 2150?

51  
52 MR. SPAFFORD: A: I think what you would find is that  
53 absent a management decision to restrict that draw down,  
54 that the optimal long term operating strategy would  
55 probably be in that one water sequence -- or at least in  
56 a low water sequence like the one you described, that  
57 the optimal operating strategy from a long term  
58 perspective would be to draft the reservoir below 2150.

59  
60

1 At TR Volume 19, pages 3308 - 3311:  
2  
3

4 MR. AUSTIN: Q: And in the paragraph, first paragraph  
5 in the table on the bottom, second sentence it says,  
6 "System reservoir levels are currently fairly  
7 low and are projected to remain fairly low  
8 throughout F2005 and F2006. This diminishes  
9 the ability of the system storage to  
10 participate in mitigation for low inflows.  
11 Therefore, while there may be some additional  
12 draft to system storage, additional market  
13 purchases will provide the primary mitigation  
14 for low inflows."...

15 MR. AUSTIN: Q: So the question I have for you is, if we  
16 don't have normal inflow conditions over the next two  
17 years, and we have something similar that occurred --  
18 similar inflows that occurred during the period in the  
19 late '70s and early '80s. Two questions: one, and I  
20 think I've got the answer to that, is it's probable that  
21 Williston would be drafted below twenty-one fifty, is  
22 that correct?  
23

24 MR. SPAFFORD: A: I think our current projections are to  
25 actually draft Williston to that level, yes, or close to  
26 that level anyway.  
27

28 MR. AUSTIN: Q: And would reservoir -- would imports  
29 increase, and if they would, approximately by how much?  
30

31 MR. SPAFFORD: A: Certainly imports would increase  
32 relative to the projections that were contained in the  
33 evidentiary update. The question by how much is  
34 difficult to answer. It would really depend on how long  
35 those were -- how long those weather conditions were  
36 sustained and how bad they got. So I can start off by  
37 saying that what we're seeing right now is that  
38 conditions are expected to be more adverse than they  
39 were when we filed the evidentiary update. So as of  
40 January, the weighted average system inflow forecast was  
41 about 94 percent of average. As of yesterday when we  
42 got a new forecast of June, that had dropped to about 89  
43 percent of average.

44 In May when the last set of studies were  
45 done, we had a weighted average system inflow forecast  
46 of about 90 percent of average, and in total we saw that  
47 there was approximately 1,000 GWh that dropped from 94  
48 to 90 percent of average, resulted in about 1,000 GWh of  
49 lost hydroelectric generation, and therefore would have  
50 required 1,000 GWh of additional purchases and/or  
51 Burrard generation. Currently today we see that the  
52 economic source of energy would be from imports.  
53 So as a result of that change in forecast,  
54 we're seeing that the cost of energy going forward is  
55 going to be roughly in -- based on the May studies it  
56 was about \$70 million more than the projections in the  
57 evidentiary update. Based on a quick back-of-the-envelope  
58 calculation with the forecast we received  
59 yesterday, we're looking at about \$90 million more than  
60 the evidentiary update.  
61

1  
2 The IPPBC submits that BCH's excessive reliance on non-firm energy imports is not  
3 consistent with the Energy Policy and poses a serious risk to BCH's ability to supply  
4 energy to its customers. The impact on BCH's revenue requirement during the Test  
5 Period could be very damaging if import prices remain high, or climb even higher. By  
6 deferring purchases and drafting scarce storage because of high import prices, BCH is  
7 taking a chance that providence will provide an abundance of precipitation in the  
8 succeeding water year or that import prices will not go any higher. This is not planning,  
9 it is uncovered optimism that could have serious financial and reliability consequences.

## 10 11 **5.1 Williston Reservoir Levels**

12  
13 Historically, BCH has taken the position that it is entitled to drawdown the Williston  
14 reservoir to the minimum level set out in the Water Licence for this reservoir. The best  
15 description of this issue is set out in a Province of British Columbia public document  
16 entitled "*Strategic Considerations for a New British Columbia Energy Policy, Final*  
17 *Report of the Task Force on Energy Policy*" and dated March 15, 2002. On pages 38-  
18 39 can be found the following:

19  
20 "Reservoirs - which are storage facilities - play essential roles in hydro electric  
21 power generation, particularly in low water years. The Williston Reservoir plays a  
22 direct role in supporting electricity generation on the Peace River. The current  
23 water licence for the Williston Reservoir permits the use of 32 million acre-feet of  
24 storage below the 2,205 foot level. As such, the minimum permitted elevation of  
25 the Williston Reservoir is 2,106 feet. However there have been requests to  
26 restrict the minimum level to 2,150 feet because of the potential impacts on  
27 industrial and some recreational interests. Restricting access to water between  
28 2,150 and 2,106 has significant financial and electricity supply implications. The  
29 amount of energy stored in Williston between the elevations of 2,150 and 2,106  
30 feet is about 6,200 GWh. In general, a 2,150 foot constraint can be  
31 characterized as one which has a low probability of impacting system operation,  
32 but one which may have a high cost consequence. If that stored energy is not  
33 available for release during a drought period, then the firm energy capability of  
34 the BC Hydro system is reduced by about four per cent. This is equivalent to a  
35 requirement for an additional 250 MW generator."

36  
37 At TR Volume 20, page 3500-3501 can be found the following:

38  
39 Mr. SPAFFORD: A: Well the recommended settlement on the Peace water use  
40 plan is a fairly complex arrangement that says that under certain events of low  
41 flow conditions - in essence, the way the plan would work is that we would have a  
42 normal minimum elevation established, and let's say for the sake of argument that  
43 minimum elevation is 2150, and then there would be certain conditions where the  
44 minimum elevation permitted in future year would be ratcheted downwards or  
45 ratcheted upwards from the minimum elevation permitted in a previous year.

46  
47 So for example, if the weighted system inflows to the B.C. Hydro system, if the  
48 actual weighted system inflows was below a certain level, and let's say for sake  
49 of argument that that was 95 percent, if we could demonstrate that the actual  
50 inflows were 95 percent, then the minimum permitted in the subsequent year  
51 would be 10 feet or some number lower than the minimum permitted in the  
52 previous year. So there would be this mechanistic formula. Given what actually  
53 occurred on the B.C. Hydro system, then the minimum permitted level would be  
54 adjusted each year as we went forward. And the idea behind that is to allow B.C.

1 Hydro to draft the reservoir during low inflow events and during events of *force*  
 2 *majeure* on the B.C. Hydro system.

3  
 4 So things like if we had a significant dam safety or event at a power house which  
 5 limited the ability to get generation from one part of the B.C. Hydro system, it  
 6 would give us greater flexibility to operate Williston in those events. So the idea  
 7 is to constrain the normal operation but allow Williston to be drafted in the  
 8 unusual drought and unusual *force majeure* events.  
 9

10 Under the heading "*Conclusion*" there is additional information about BC Hydro's ability  
 11 to drawdown its Mica and Williston reservoirs including:

- 12  
 13 • There is significant pressure to prevent Williston reservoir from drafting below  
 14 2,150 feet. Historically, the reservoir has drafted to 2,147 feet in 1989 and in  
 15 1997 with little to no adverse impact on the local industries. Nevertheless, these  
 16 industries have focused on the 2,150 feet. Given the timing of the potential low  
 17 elevations in 2005, there could be significant risks to the draft Water Use Plan  
 18 stakeholder consensus if elevations proved unacceptable.  
 19

20 BCH does not have the flexibility it once claimed to have with respect to drawing down  
 21 its Williston reservoir below the elevation of 2150 feet. It now uses phrases such as  
 22 "*unusual drought*" and "*unusual force majeure*". When put to the practical test i.e. as  
 23 per the response immediately above and as described in more detail under the heading  
 24 "*Conclusion*" it is highly unlikely the reservoir will be drawn below 2150 - 2148 feet.  
 25

26 The new reality, and its impact on BCH's energy supply will have to be tested in a full,  
 27 public BCUC review of BCH's IEP. It is certainly clear that BCH will have to purchase  
 28 some additional supplies of energy to make up the shortfall. It is also clear that the  
 29 49,000 GWh figure in the Heritage Contract will probably have to be adjusted. An  
 30 adjustment will also probably have to be made because of the circumstances pertaining  
 31 to the operation and management of the Burrard Thermal plant.  
 32

## 33 **6. Boosting Revenues - The Beer and Wine Fridge Analogy**

34  
 35 There is a tendency during revenue requirement hearings for participants to concentrate  
 36 their efforts on decreasing utility expenditures. However, it is highly probable that BCH  
 37 can generate additional revenues and increase the reliability and security of its  
 38 electricity supply by acquiring additional supplies of electricity from B.C. IPPs. It is also  
 39 highly probable that revenues can be increased if third parties are given limited access  
 40 to BCH's storage capabilities i.e. IPPs so they can sell to Tier 2 customers and for  
 41 export. Currently this storage is monopolized by BCH and its trading subsidiary  
 42 Powerex.  
 43  
 44

### 45 **6.1 Stocking the Fridge with Domestic Product**

46  
 47 During cross examination, the IPPBC illustratively compared BCH's reservoir storage  
 48 system to a large beer and wine fridge. In many ways, BCH's storage is not much  
 49 different than the than the beer and wine fridge at the local beer and wine store.

1 The idea was to discuss in as simple and practical terms as possible how BCH might  
2 increase its revenues by stocking this fridge with more domestic product and by giving  
3 third parties the right to rent storage in it.

4  
5 In the 1980's and into the 1990's BCH's fridge was stocked exclusively with B.C. beer  
6 and wine. During this period and prior years, BCH was self-sufficient in electricity  
7 during the drought of record during the 1940's. Most of the time it had surplus electricity  
8 to sell, and through prudent use of storage, it was able to sell the surplus at optimal  
9 times. When BCH's Revelstoke project came into service, supply exceeded demand  
10 even during the drought of record but BCH was able to successfully sell this electricity  
11 even though access to U.S. transmission lines was heavily restricted.

12  
13 From the mid 1990's until the present day, BCH has abandoned the standard of being  
14 self-sufficient during the drought of record. Officially, it claimed it would only have to  
15 import 2,500 GWh of electricity during this period. In order to make this claim, it  
16 overstated the amount of electricity that could be realistically produced at Burrard, and  
17 glossed over the implications of drawing the Williston Reservoir below the 2150 foot  
18 elevation level.

19  
20 The beer and wine fridge now has a significant amount of imports in it i.e. 10% this year  
21 for domestic requirements, and an unknown amount of imports solely for re-export  
22 purposes.

23  
24 In response to the beer and wine fridge analogy about whether BCH would make more  
25 money if it had more domestic product vs. imports BCH said:

26  
27 TR Volume 6, pages 665-657:

28  
29 MR. AUSTIN: Q: Now, assuming that you got that access  
30 to the US market, has B.C. Hydro ever considered that it  
31 would have made just as much, if not more money if that  
32 beer and wine fridge was stocked exclusively with  
33 domestic product versus the product it now has in there  
34 now?

35  
36 MR. ELTON: A: I can't answer that really. I mean, I  
37 wasn't -- you know, frankly I wasn't there. I don't  
38 have enough knowledge of precisely what happened in, for  
39 example, the early 1990s and what the alternatives were,  
40 and in particular, you know, how many beer manufacturers  
41 there were in the province.

42  
43 MR. AUSTIN: Q: Well, that fridge, I can assure you that  
44 when the Revelstoke project came on in the mid-eighties,  
45 that B.C. Hydro beer and wine fridge was stocked, chocka-  
46 block full with B.C. Hydro and B.C. Hydro only  
47 product.

48  
49 MR. ELTON: A: I certainly -- I'm sorry, you'll have to  
50 repeat the question. I still have this vision of  
51 this --

52  
53 MR. AUSTIN: Q: My observation, and you can disagree

1 with it, was that when the Revelstoke project came on in  
2 the mid-eighties that B.C. Hydro beer and wine fridge  
3 was stocked chock-a-block full with B.C. Hydro beer and  
4 wine.  
5

6 MR. ELTON: A: I mean, I think that's largely true. I  
7 mean, there was a point at which B.C. Hydro certainly  
8 was doing transactions with Alberta. So there were  
9 Alberta beer and wine there as well, but largely true,  
10 yes.  
11

12 MR. AUSTIN: Q: So B.C. Hydro hasn't done an analysis to  
13 sort out whether it could make more money running the  
14 fridge like it did in the 1980s versus the way it does  
15 now?  
16

17 MR. ELTON: A: Well, I think, I think that what we've  
18 done over the last few years is to look at what the  
19 possibilities were, and certainly the possibility -- I  
20 mean, again we're talking about making short-term --  
21 when we're talking about stocking our, quote, beer and  
22 wine fridge, we're talking about -- you know, it might  
23 be easier to talk about it as a reservoir. I'm  
24 struggling -- I'm sorry, I usually love analogies but  
25 I'm struggling to keep up with you there.  
26 So what we're doing is making daily, weekly,  
27 hourly decisions, seasonal decisions to store or not  
28 store in the reservoir, and using the market and  
29 whatever the market brings to us. So at the moment a  
30 lot of it's from Alberta or it might be from the States,  
31 and if it was from B.C. we'd be certainly, you know,  
32 we'd be certainly doing that. In other words, the  
33 trading operation doesn't really differentiate between  
34 where the electricity comes from and where it goes to.  
35 It just buys and sells at the right prices.  
36

37 MR. AUSTIN: Q: Yes.  
38

39 MR. ELTON: A: And of course -- I'm sorry, and of course  
40 the benefit of that, you know, through the Heritage  
41 Contract submission that we made that was accepted by  
42 the Commission and then by the government, the benefit  
43 of that goes to the customers, and that's an important  
44 point for us. So that we're operating the whole system,  
45 the storage system for the benefit of the ratepayers.  
46

47 MR. AUSTIN: Q: I certainly agree with that, but would  
48 you agree with me that you are the owner of the fridge,  
49 and people using it for trading purposes is a separate  
50 issue.  
51

52 MR. ELTON: A: I agree that we're the owner of the  
53 fridge, yes.  
54

55 MR. AUSTIN: Q: But you haven't done that analysis in  
56 terms of those two examples that I gave to you.  
57

58 MR. ELTON: A: Well, because I'm not sure I understand.  
59 This is where we're going there from the analogy to our  
60 situation, and I'm not sure I understand where it goes.  
61 What I'm saying is that, you know, we don't care whether  
62 the beer in the fridge is from Alberta or B.C. or from

1 the United States. We buy on the market. In fact, we  
2 don't even know where it comes from, so it's just a can  
3 with no label on it, and I think that's appropriate.  
4 So I think a different question then is, you  
5 know, what are the -- in other words, for me to answer  
6 the question differently, there would have to be a lot  
7 of, for example, IPPs in B.C. that there aren't today,  
8 that would be more involved in trading. But we will  
9 trade with whoever. Whoever has available supply, we'll  
10 trade with them.

11  
12 MR. AUSTIN: Q: Or more IPPs that you as the owner of the  
13 fridge can contract for on a long-term basis to keep  
14 that shelf space filled with more B.C. product, correct?

15  
16 MR. ELTON: A: We see it as two separate decisions. We  
17 think that what we should do is make the right decisions  
18 about acquiring resources, and that's the processes that  
19 Ms. Van Ruyven has talked about, acquiring those kinds  
20 of resources.

21 In terms of our trading activity, we run it  
22 as a separate business and we think quite appropriately.  
23 It's very much -- generally speaking it's the business  
24 that's focused on the short term. So for example, a two  
25 or three year contract for that business is a long time,  
26 and what they're doing is taking advantage of whatever  
27 is there, and I think they're two separate activities.

28  
29 MR. AUSTIN: Q: But what I'm suggesting is if you look at  
30 the product and the product that might be available,  
31 that you might be able to make more money in one  
32 circumstance versus the other. And quite frankly, I  
33 don't know the answer to that, so what I'm asking you is  
34 have you ever done an analysis?

35  
36 MR. ELTON: A: I think two answers to that. The first  
37 is that whenever Powerex is pursuing opportunities, it  
38 does actually look at opportunities in B.C. as well as  
39 opportunities outside B.C. So I think that the answer  
40 is that we are actually always interested in that.

41 In terms of -- again, let's talk about the  
42 type of activity, and I think I understand the question.  
43 The type of activity we're talking about is typically  
44 we're buying light load arrows. We're buying cheap  
45 energy. We're trying to sell at heavy load times or at  
46 seasonal peaks. So from the point of view of an  
47 independent power producer in B.C., which I assume is  
48 the kind of B.C. producer you're talking about, an  
49 independent power producer in B.C., they certainly  
50 couldn't live off what they could get from trading,  
51 because what they'd be selling into the market would be  
52 the cheapest energy, because that's the only time we'd  
53 want it. So they'd still need to have a long term  
54 contract with somebody, and that could be us or it could  
55 be another utility before they could get going. I don't  
56 think the market right now generates a lot of interest  
57 in people building for purely merchant purposes. So, I  
58 understand the question, I think I understand the  
59 question, but I don't think that we see a circumstance  
60 where we should change the way that we do the trading  
61 business, because I think the way we do the trading  
62 business right now is to maximize revenues for the

1 benefit of the ratepayer, and so I don't -- no, I don't  
2 see how we could do it differently.

3  
4 MR. AUSTIN: Q: But Mr. Elton, this is a revenue  
5 requirements hearing. One way to keep rates down is to  
6 increase your revenues, make a bigger pie, correct?  
7

8 MR. ELTON: A: Yes, yes.  
9

10 MR. AUSTIN: Q: So you have a lot of people in this room  
11 saying, get your costs down. I'm asking you to -- I've  
12 asked you whether you'd considered in a way, a potential  
13 way to increase your revenues.  
14

15 MR. ELTON: A: No, and I appreciate the question, and  
16 what I'm saying is that we -- within the kind of  
17 parameters of the trading business that we currently  
18 have, which is mainly a short-term business, we do look  
19 at all the possible sources in the market every day,  
20 every hour, every week, and you know, I'm confident that  
21 as a result of that that we get the best results.  
22 Now, should there be a different business in  
23 B.C. Hydro that involves, you know, changing that model  
24 and looking at longer term possibilities, again what I'm  
25 saying there is we have -- you know, we've certainly  
26 thought about those kinds of possibilities, but we don't  
27 see an economic model that would increase our revenues.  
28 So I think the answer is no.  
29

30 MR. AUSTIN: Q: So have you ever tried to build one?  
31 Have you spent any money on a financial model in terms  
32 of using the longer-term beer and wine supply to stock  
33 your fridge versus what you're doing short term, to see  
34 whether over the short, medium, long term whether you'd  
35 come out ahead, behind, neutral?  
36

37 MR. ELTON: A: I think that as time goes on we'll  
38 certainly do more of that thinking. I mean, it's  
39 certainly incumbent on us to keep thinking about what  
40 the market possibilities are around the region. Again,  
41 though, to interpret those in the context of the Energy  
42 Plan, today we don't have that kind of planning in  
43 place.  
44

45 MR. AUSTIN: Q: Would you object to this panel, as part  
46 of its hearing conclusions, asking you to perform that  
47 type of analysis?  
48

49 MR. ELTON: A: I don't think we'd object -- sorry.  
50 I was about to say that if at the end of this  
51 hearing the panel, this panel asked us to do analysis, I  
52 think our almost invariable answer would be to say that  
53 we'd do it. I mean, that's just a general comment, that  
54 my counsel is probably going to be concerned about.  
55 But I think that I'm not clear enough about  
56 what that kind of analysis would look like. In other  
57 words, I understood -- I understand generally what  
58 you're saying, but somewhere between the beer and wine  
59 fridge and the reservoir I'm not sure exactly what it is  
60 that we'd have to do, what analysis it would be, that if  
61 there was something that was, you know, that was a clear  
62 direction to do analysis, that we could look at that

1 would see whether or not we could add value, of course  
2 we'd do that.

3 I think frankly we should be doing that  
4 anyway. There are such things. But I'm not sure I  
5 understand the question well enough to be able to say  
6 yes we would do that analysis.  
7

8 MR. AUSTIN: Q: Would you be prepared to consult with  
9 groups such as the IPPBC to help assist in framing that  
10 analysis? That's one way of overcoming your problem.  
11

12 MR. ELTON: A: I mean -- so taking the question I think  
13 away from this hearing, of course, we'd be delighted to  
14 consult with the IPPBC and discuss the kind of issues  
15 you're talking about and see whether there are ideas  
16 that could help our business, absolutely.  
17

18 This evidence is directly contradictory to the evidence found on page 1-10 of Volume 1  
19 of BCH's Application:

20 "Within the very significant capacity of BC Hydro's interties with other jurisdictions , energy can be  
21 purchased as needed from the United States or Alberta. Nevertheless because of the price  
22 volatility of those markets, BC Hydro has planned its resource acquisitions to avoid having to make  
23 extra-Provincial market purchases under average water conditions. The cost of supplementing  
24 below average water through market purchases is higher than the likely benefit of above average  
25 water conditions, and this asymmetry must be considered in planning. The cost of under planning  
26 is significant loss of potential dislocation for customers, whereas the risk of a resource surplus can  
27 be mitigated by trading surplus energy in the market."  
28

29  
30 BCH's evidence on cross-examination is also contradictory to BCH's decision to scrap  
31 its reliance on 2,500 GWh of imports during the drought period for the purposes of its  
32 latest IEP.  
33

34 TR Volume 12, page 1821:

35 MR. AUSTIN: Q: I certainly appreciate that, but isn't  
36 this sentence basically saying that it's better to err  
37 on the side of having a little bit more energy than  
38 having a little bit less energy?  
39

40 MS. HEMMINGSEN: A: Well, actually that was the analysis  
41 that was done in the IEP where we explored a range of  
42 imports from minus 3,000 to plus 3,000, and we found it  
43 was best to rely on between zero -- no market import  
44 allowance -- up to plus 3,000. At minus 3,000 there was  
45 economic costs imposed on the ratepayers according to  
46 that analysis.  
47

48 However, BCH continues to import growing amounts of electricity as per:

49  
50 TR volume 12, pages 1827-28:

51 MR. AUSTIN: Q: Well, let's say -- I'm concentrating on  
52 firm energy because that what IPPs are best at  
53 supplying.  
54  
55

1 MS. HEMMINGSEN: A: Well, we don't need the firm energy  
2 from Burrard because we're not in a critical water  
3 sequence. We're in a low water sequence, but not a  
4 critical water sequence.  
5

6 MR. AUSTIN: Q: But we're importing 5,000 GWh of  
7 electricity. What difference does it make?  
8

9 MS. HEMMINGSEN: A: Because generation makes a decision  
10 about what's the most optimal resource to access to meet  
11 load. So they --  
12

13 MR. AUSTIN: Q: It may be making that decision, but over  
14 top of that decision making process presumably you have  
15 some thoughts about what's going to happen in the  
16 future. And are you telling me that you're happy to see  
17 5,000 GWh of imports?  
18

19 MS. HEMMINGSEN: A: Well, we certainly have some  
20 thoughts, and as I've said before, that's one of the  
21 reasons that we want to look at the whole issue, from  
22 both a Generation operation perspective and Distribution  
23 planning perspective, pursuant to the REAP. That's why  
24 we've identified that issue.

25 But at this point in time we're not concerned  
26 for the current period. We believe that we have made  
27 the appropriate decisions with respect to Burrard in the  
28 short-term operating horizon, and we'll evaluate  
29 Burrard's contribution over the long-term.  
30

31 MR. AUSTIN: Q: It would appear to me, though, that's  
32 contradictory to what you've just said about the IEP,  
33 where you're saying that 2500 GWh of imports is (a) not  
34 consistent with B.C. Hydro's security requirements, and  
35 on a price basis it's cheaper to move towards selfsufficiency.  
36 So from my perspective I'm looking at  
37 5,000 of imports in 2004, plus 2500 GWh that you've now  
38 said ought to be supplied domestically, and all I'm  
39 seeing is a provision for 400 GWh worth of energy on  
40 energy calls in the next two years. Does that make any  
41 sense?  
42

43 MS. HEMMINGSEN: A: Well, I think you're mixing up a  
44 couple of concepts here. One is the 2500 gigawatt hour  
45 market allowance is determined based on assessment of  
46 the firm resources to meet the expected load under  
47 critical water conditions. So that's how that 2500  
48 gigawatt hours is determined.

49 The actual market usage is determined by  
50 economic factors. So 5,000 gigawatt hours would be  
51 determined by the fact that it was more economic on a  
52 short-term operating basis to buy non-firm resources  
53 from the market. So the two are distinct issues.  
54

55 The short - term market price has been very close to long term firm IPP cost, which for  
56 run of river hydro project is indexed at one-half of CPI.  
57

58 TR Volume 12, pages 1821-1822:  
59

60 MR. AUSTIN: Q: Without getting into the details of the  
61 IEP, would you agree that the current situation, where

1 you're importing -- or you did in fiscal 2003 importing  
 2 5,000, approximately 5,000 GWh of energy and it's not a  
 3 critical water period, is something that that same  
 4 analysis would apply to?

5  
 6 MS. HEMMINGSEN: A: Well, in 2000 -- I believe you're  
 7 referring to fiscal 2004.

8  
 9 MR. AUSTIN: Q: Fiscal 2004, yes.

10  
 11 MS. HEMMINGSEN: A: And my understanding is we source  
 12 that supply at \$50 per megawatt hour, and that's  
 13 slightly below what we have sourced our long-term supply  
 14 from the IPPs at \$51.  
 15  
 16

17 The price is right, the evidence is that it is cheaper to stock the beer and wine fridge  
 18 with more domestic product so the question is: *"Why, strictly from a revenue*  
 19 *requirements perspective, isn't BCH acquiring more electricity from IPPs?"* If the BCUC  
 20 does not respond favourably to the IPPBC's request for a prompt, full, public review of  
 21 BCH's IEP, then the IPPBC requests the BCUC to order BCH to acquire at least 3,000  
 22 GWh of electricity from IPPs through a competitive bidding process.  
 23

## 24 **6.2 IPP Access to the Fridge**

25  
 26 The concept of making storage available to third parties to produce additional revenues  
 27 to BCH was also discussed by reference to the beer and wine fridge analogy,  
 28

29 TR Volume 6, pages 666-669:  
 30

31 MR. AUSTIN: Q: Have you ever done an analysis to  
 32 consider whether, for example, if you auctioned some of  
 33 that space off on a short-term basis, whether that might  
 34 produce more revenue for all of B.C. Hydro's customers  
 35 as opposed to B.C. Hydro and Powerex in a sense making  
 36 that decision for you?  
 37

38 MR. ELTON: A: Our view is that managing the storage  
 39 capacity of our system is best done overall. We  
 40 recognize that -- we recognize the value of that system,  
 41 and that's one of the reasons why in the Heritage  
 42 Contract hearing we proposed that all of the benefits of  
 43 that go to the ratepayer, because we think that (a)  
 44 running the system as a whole is the best way to  
 45 maximize the pie, to use that -- and I realize that  
 46 maximizing the pie doesn't fit very well with the beer  
 47 and wine story, but that's a different issue. So we  
 48 think that's the best way to maximize the pie.  
 49 And if we were to get into a complex series  
 50 of, as you say, auctioning off the storage, we believed  
 51 and believe that by doing that we would be taking the  
 52 value of the Heritage Assets and giving that value, or  
 53 dealing that value off to some other group, and we don't  
 54 believe that's something that we were permitted to do  
 55 and we believe that's reflected in the conclusions of  
 56 the government in response to the Heritage Contract  
 57 recommendations.  
 58

1 MR. AUSTIN: Q: Mr. Elton, are you telling me that if you  
2 were able to auction it off and you were paid for this,  
3 and I'm just saying auction a small portion of it off  
4 just as a trial example, and you got the revenue from  
5 that, the revenue is not going to go to B.C. Hydro's  
6 customers?  
7

8 MR. ELTON: A: I'm saying that I believe that we don't  
9 have the ability to auction off pieces of the Heritage  
10 Assets. I believe that that direction could not be  
11 clearer from government. It was clear on the Energy  
12 Plan. It's been made clear several times since,  
13 whenever any discussions have taken place about any  
14 possible actions that we might take with respect to  
15 those assets, and I believe it was also clear in the  
16 Heritage Contract hearing. So I don't believe that we  
17 have the ability to sell value that's in the Heritage  
18 Assets, and I believe that the storage capability of our  
19 reservoirs is included in that value.  
20

21 MR.AUSTIN: A: So how can you say in your opening  
22 statement that you've maximized the value if you've got  
23 no benchmark against which to put it?  
24

25 MR. ELTON: A: Well, again, let's take another analogy, a  
26 different analogy or comparison. Supposing you told me  
27 or somebody said to me that you might be able to get  
28 more value out of one of the Heritage Assets by selling  
29 it, so for example, by selling all of them. My answer  
30 would be we haven't considered that. We haven't studied  
31 that because our instructions in the Energy Plan and in  
32 the way the Heritage Contract is structured are clear  
33 that we must not do that. So we do not consider ways of  
34 selling to third parties the benefits of the Heritage  
35 Assets. Our mandate, we believe, is to operate those  
36 assets in the best way possible, and that benefit will  
37 go to the ratepayers.  
38

39 MR. AUSTIN: Q: Mr. Elton, I'm not suggesting for a  
40 minute that you're selling or auctioning off the  
41 Heritage Assets. What I'm suggesting is that you're  
42 auctioning off or selling the right to maximize the  
43 value of those particular assets. And could you tell me  
44 what the difference between that is and BCTC selling  
45 space on its transmission lines to third parties?  
46

47 MR. ELTON: A: Well, BCTC's ability to -- again, you'll  
48 have to ask BCTC about it's mandate, but I'll just make  
49 a general comment that the Heritage Assets are defined  
50 in a certain way and they don't include, as far as I  
51 know, BCTC's assets. That's a different -- they're  
52 covered by a different set of rules and you must ask  
53 them about that.

54 I don't think -- I think to say that there is  
55 -- you know, on the one hand you could sell the assets  
56 or you could sell the value, the ability of the assets  
57 to create value to me, that's very much the same thing.  
58 So for example, we could lease the Heritage Assets and  
59 make large amounts of money in the short term, but that  
60 is not what we are allowed to do. We are not allowed to  
61 sell or dispose of the value of those assets.  
62

1 While the above responses were interesting, they are not consistent with BC Hydro's  
2 past practices where third party storage was made available to third parties.

3  
4 At TR Volume 19, pages 3315-3316:

5  
6 MR. Austin: Q: And this was in relation to a question that  
7 IPPBC had about third party storage, and the response is  
8 "please see IR 1.80.4," and when we looked at 1.80.4  
9 we really didn't see an answer. So perhaps –

10  
11 MR. SPAFFORD: A: I noticed the same thing after this  
12 had been submitted. Basically it's very difficult for  
13 us to actually obtain the information on what third  
14 party storage was in the system at any given point in  
15 time. There's very limited third party storage.

16  
17 MR. AUSTIN: Q: Okay, maybe I could just help you out.  
18 In terms of the actual numbers I think we can dispense  
19 with that, but would you agree that B.C. Hydro does  
20 engage in third party storage transactions?

21  
22 MR. SPAFFORD: A: Only to a very very limited extent.  
23 The only case that could potentially be interpreted as  
24 third party storage I think is the non-treaty storage  
25 agreement, and that's a fairly complex storage agreement  
26 that we have with Bonneville Power administration. And  
27 the reason that one is a special case I think is because  
28 the operation of that storage affects not only our  
29 projects but projects downstream in the United States.

30  
31 MR. AUSTIN: Q: So you've never entered into any –

32  
33 MR. SPAFFORD: A: No, I didn't say never. We used to  
34 routinely enter into storage agreements with Bonneville.  
35 Back in the late '80s, possibly early '90s, we made a  
36 deliberate decision not to engage in storage but only to  
37 engage in the buying and selling of energy.

38  
39 MR. AUSTIN: Q: But you have in the past engaged in  
40 storage transactions.

41  
42 MR. SPAFFORD: A: Yes, we have in the past.

43  
44 The real reason BCH denies third party access to its storage is because of a business  
45 decision that was made in the late 1980's. It doesn't have anything to do with the  
46 sanctity of the Heritage Assets. Ironically, the Mica facilities on the Columbia River  
47 provide third party storage to the United States under the Columbia Treaty.

48  
49 Although on cross-examination, the IPPBC used the example of third party access to  
50 BCH's storage, the same arguments apply to IPP access to storage for the purposes of  
51 sales to Tier 2 customers and for exports. The IPPBC requests the BCUC to require  
52 BCH to provide the business case as to why IPPs can not have access on a fee paying  
53 basis, to BCH's storage capabilities for the purposes of making these sales.

54  
55

## 7. Level Playing Field

IPPs have been fighting for a level playing field with BCH since the first significant IPP projects were developed in B.C. in the late 1980's. The IPPBC's mission statement should be changed to read: *"seeking a level playing field for resource acquisition and transmission access."* Given the amount of time and resources that the IPPBC has consumed on this mission, a slightly tilted playing field in favour of BCH would do. The matter has been raised at previous BCUC proceedings including during the BCUC's British Columbia Electricity Market Review. In the BCUC's *"Report and Recommendations to the Lieutenant Governor in Council dated September, 1995"* the following can be found at page 23:

"First several parties expressed concern with respect to the current resource acquisition process, in which vertically integrated utilities act as both bidder and evaluator of resource projects. For example the IPPBC stated that because BC Hydro acts as a dominant player, referee, and owner of the field, is owned by the rulemaker and is scrutinized by the rulemaker's regulator, there could be no assurance of a level playing field and a competitive electricity market (T. 14, 2642). As a result there was near unanimous agreement that B.C. Hydro should be restricted from building new generation as long as it continued to determine which new potential resources would be developed. In particular, the Council of Forest Industries, the Mining Association of British Columbia and the Electrochemical Producers (the "Industrial Customers") argued that B.C. Hydro should be required to purchase all its new generation from the spot market or from IPPs, unless the generation was associated with existing B.C. Hydro facilities and was clearly economic as determined by an independent third party (T. 15, 2675). The Consumers Association of Canada, B.C. Branch et al. ("CACBC") suggested B.C. Hydro be prohibited from all new generation, including upgrades at existing facilities (T. 14, 2642)."

The fully functioning spot market envisaged by the IPPBC and others developed in Alberta and in some jurisdictions in the U.S. But it did not happen in B.C.

At page 51 of the Report and Recommendations under the heading *"6.3 Resource Acquisition"* it states:

"As noted in Chapter 4, there was near universal agreement in the Review that the current method of resource acquisition, which allows utilities to both bid and evaluate resource projects, does not lead to a level playing field for all resource providers. Several participants suggested that B.C. Hydro, and presumably WKP, be restricted from building new generation as long as these utilities continued to determine which new potential resources would be developed.

In response to these concerns, B.C. Hydro argued that it is essential that it be able "... to participate fully in the identification and development of new resources..." (T. 14, 2479). Further, B.C. Hydro felt that it could play the role of bidder and evaluator, but noted that "... if it was determined that the dual role is inappropriate then the evaluation process could be carried out by a different agency" (T. 14, 2480).

The Commission believes the current requirement for utility IRPs overseen by the BCUC, acts to promote the acquisition of new generation resources based on the principles of least social cost. Nonetheless, the Commission agrees with almost all the participants that there is an internal conflict of interest in having the utilities act as both generation competitors and decision makers with respect to

1 new resource acquisitions. As a result, if the Incremental Changes Option is  
2 chosen, the Commission believes that in the future B.C. Hydro and WKP should  
3 be restricted either to the role of resource bidders or resource evaluators, with  
4 the possible exception of upgrades to existing facilities. Even these upgrades  
5 should be promoted and developed by third parties through leasing or similar  
6 arrangements. In either case, the Commission sees a continued role for IRP in  
7 resource selection. The Commission needs information from the IRP process to  
8 judge the prudence of utility investments or energy purchases. If the utilities are  
9 allowed to continue as resource bidders, several complex issues need to be  
10 solved in order to assure a level playing field. Such issues include the separation  
11 of financing of new generation, and the development of fair criteria and  
12 processes for evaluating utility and non-utility proposals.”

13  
14 Nine years later and with a few twists, almost nothing has changed. BCH doesn't have  
15 a common financial screen that it is consistently applied with respect to all capital  
16 expenditures that are directly or indirectly related to meeting the electricity requirements  
17 of its customers. This includes Power Smart and Resource Smart. It can't produce any  
18 reasonable financial analysis that it has used for its proposed Site C, Revelstoke and  
19 Mica projects.

20  
21 BCH has "*three buckets*", in which different options within each "bucket" can be  
22 evaluated, but no single bucket approach to financial screening that would fairly  
23 compare options across the board.

24  
25 BCH is using Burrard and Power Smart as means of claiming that it doesn't need any  
26 new supplies of electricity from IPPs, except for 400 GWh later this year. These shields  
27 are full of holes. Meanwhile, electricity imports climb upwards even when reservoir  
28 inflows are about average over the last three years. If nothing is done to correct the  
29 import situation, it will be even worse when a real drought occurs.

30  
31 Imports will increase if Power Smart savings are not realized, and/or the demand for  
32 electricity is more than forecast.

33  
34 For IPPs, the idea of a level playing field is as illusory as ever. Site C, Burrard, Power  
35 Smart, imports, BCH's Vancouver Island Generation and BCH's resistance to a public  
36 review of its IEP are a few of the more notable examples of "*no change*".

37  
38 Although the formation of the BCTC has helped, there is still the burden created by the  
39 inclusion of the long transmission lines that serve BCH's large remote generating  
40 facilities as part of BCTC's core transmission system that all third party users of the  
41 transmission system have to pay for. Perhaps the BCTC will come up with some  
42 means of addressing this fundamental flaw, but to date, IPPs have seen no evidence of  
43 this. It is one thing to consult, and yet another to address the issues that are brought  
44 forward and act upon them.

45  
46 As set out under the heading "*The Energy Plan*":

47  
48 "When deciding how to meet a projected power need, BC Hydro's distribution  
49 business will compare the costs of all potential resources, including IPP  
50 purchases, customer-owned generation, BC Hydro plant efficiency improvements

(Resource Smart) conservation and energy efficiency, and firm imports ... The BC Utilities Commission will oversee the acquisition process to ensure that least-cost options are chosen consistent with an new clean energy goal..."

The IPPBC requests that the BCUC order BCH to come up with a workable plan, complete with measurable milestones and deliverables within 3 months of its Review decision that meets the above element of the Energy Plan. As described in more detail under the heading "*Full Public Review of IEP*" the IPPBC requests that the BCUC order a full public review of this document. These two measures will not create a level playing field but they will be welcomed first steps.

A level playing field will keep the cost of new supplies of electricity as low as possible.

## 8. Full Public Review by the BCUC of the IEP

The IPPBC has heard all of BCH's protest and complaints against full regulatory oversight of its IEP before. The main question is "*What is it going to take before BCH gets the message that it is a regulated utility and that in the absence of a fully functioning competitive B.C. electricity market, its medium and long term ability to meet its customer's domestic requirement is a matter of regulatory oversight?*" For IPPs it is very frustrating to watch this issue come back to life, especially as BCH proclaims:

At TR Volume 6, pages 654-656:

MR. AUSTIN: Q: And how much is that call projected to be for?

MR. VAN RUYVEN: A: The call is 400 gigawatt hours at this point in time and on an expected basis, when you look at our load forecast, we really aren't in a capacity or energy short-fall for quite some time beyond '09, but we feel it's prudent because of the very thing you've been talking about, from a long-term planning perspective, to start that process to be less reliant on spot market purchases, and we actually do say that in our filing in Chapter 4, page 25. It says:

"B.C. Hydro does not currently consider spot market purchases under average hydro conditions, example in net domestic supply deficit to be an appropriate long-term planning option."

So we have said that. We've said it in our filing and we're saying that from a long-term perspective, we need to really pay attention to that.

How we actually operate our system on the short-term, we operate it, and yes, we do rely on imports if that is the lowest cost option to keep rates low for our customers. But on a long-term perspective, we are headed down that path. I think it actually is exactly what the energy policy is foreshadowing, and you'll see that in our 4-year REAP document that we have filed.

MR. AUSTIN: Q: Just to sum this up so we can have the

1 mid-morning break, we are importing 5,000 GWh  
2 approximately, and you've got in your budget enough for  
3 a call for 400 GWh, is that correct?  
4

5 MR. VAN RUYVEN: A: That's correct.  
6

7 BCH took the same approach in the mid-1990's to integrated resource planning ("IRP")  
8 and the matter ended up before the Courts. It was an absurd situation. One branch of  
9 Government, fighting another branch of the same Government, before the Courts, using  
10 public money.  
11

12 As part of this saga, the BCUC directed BCH to hold a full stakeholder consultative  
13 process to develop BCH's IRP. The IPPBC was a full participant in this BCH driven, and  
14 controlled process. At the end of it, the IPPBC insisted that its written comments be  
15 made part of the public record. BCH did agree, but made sure they were only included  
16 in an appendix to the main document.  
17

18 These comments have been filed in evidence in this Review as Exhibit C-4-10. They  
19 are a study in how BCH wanted no part of a level playing field for IPPs. Its 1995 IRP  
20 was a half baked plan that would have seen multiple opportunities for IPP natural gas  
21 fired generation on Vancouver Island and the Lower Mainland, and an 11<sup>th</sup> hour  
22 proposal to rebuild 4 units at Burrard at 350 MW per unit. Despite the apparent  
23 opportunities for IPPs, IPPs readily saw that the core of BCH's natural gas-fired vision  
24 was short on practical details such as the availability of natural gas transportation and  
25 the impact of air emissions caps.  
26

27 Extracts from Exhibit C-4-10 are set out below.

28 Page 1  
29

30 "No discussion of the issues can be complete without reference of the apparent  
31 attitude of B.C. Hydro's ("BCH") senior management to resource planning. The  
32 B.C. Utilities Commission ("BCUC") directed BCH and other utilities to prepare  
33 and file with it integrated resource plans ("IRP"). Unlike these utilities, BCH did  
34 not comply with the BCUC's direction and on November 24, 1994 was ordered by  
35 it to file an appropriate IRP. BCH appealed this decision to the B.C. Court of  
36 Appeal and asked the BCUC to reconsider its position. At one of the first  
37 Committee meetings, the President of BCH, Mr. John Sheehan, said to the  
38 effect, that he did not believe in the IRP process established by the BCUC  
39 because it had no place in a competitive market. Mr. Sheehan could not  
40 adequately explain how BCH's domination of the B.C. electricity market could  
41 lead to this market being characterized as "competitive".  
42

43 In adopting this position, Mr Sheehan displayed BCH's lack of understanding of  
44 the need for oversight of its planning activities. It was the reaction to this lack of  
45 understanding that lead to the creation of the IRP Committee.  
46

47 ... The material relating to the proposed re-powering of the Burrard Thermal plant  
48 was presented very late in the process and was incomplete. The financial  
49 analysis of BCH's projects was not transparent and in the case of Stave Falls  
50 was not correct...  
51

52 ... In the absence of a truly competitive electricity market, the IPABC supports  
53 IRP because it expects that it will provide interested parties with an opportunity to

1 test and examine BCH's plans to meet its customer's demand for electricity  
 2 ("Demand"). For the reasons set out below, it is the IPABC's opinion that BCH's  
 3 first real attempt at IRP fell considerably short of this expectation."  
 4

5 Page 3

6 "The model data did not take into account the prospect of air emissions caps in  
 7 the Lower Mainland that might restrict the amount of electrical generation that  
 8 could be developed and operated in the lower or upper Fraser Valley. At its May  
 9 3, 1995 meeting, the Committee requested and agreed that this topic be dealt  
 10 with in the environmental regulation scenario. Subsequently, the IPABC  
 11 Committee member was advised that it was going to be included as a scenario.  
 12 In each instance, it never was. The impact of air emissions caps has not been  
 13 adequately taken into account in the development of the portfolios."  
 14

15 "For the purposes of preparing the financial analysis for its projects, BCH  
 16 assumes that the output from its hydroelectric projects will be consumed by its  
 17 customers for a period of 70 years and for its thermal projects such as the  
 18 Burrard Plant, 25 years. The result is that B.C. Hydro is "signing" contracts with  
 19 itself for the output from its projects for 70 or 25 years respectively."  
 20

21 Page 4

22 The IPABC presented an analysis to the Committee that was based on BCH's  
 23 financial methodology which shows the cost of electricity from BCH's Stave Falls  
 24 project increasing from 1.5 cents/kWh to 3.54 cents/kWh when all costs are  
 25 included. If the amortization period is decreased from 70 to 20 years the price  
 26 increases to 4.13 cents/kWh. This price increases to 6.16 cents/kWh if there is  
 27 no abandonment credit. The analysis underlines the dangers in relying on BCH's  
 28 approach.  
 29

30 Page 5

31 "It is highly unlikely that the approximately 2000 MW of firm natural gas fired  
 32 generation that is contained in the portfolio that BCH selected for its "20 year  
 33 Outlook" could be built in the Lower Mainland and on Vancouver Island without  
 34 significant improvements to the existing natural gas transportation system...  
 35

36 To put the potential gas transportation problem into perspective, the existing 912  
 37 MW Burrard Plant in full operation consumes the equivalent of 20% of the natural  
 38 gas used in the Lower Mainland. (The 20% figure is a typing error. The actual  
 39 figure is 70%) Currently only 40 MW of this amount is supplied under a firm gas  
 40 contract..."  
 41

41 Page 6

42 Two of the key questions with respect to an analysis of the portfolios are, "How  
 43 much do they cost?" and "How does the cost of one portfolio compare to that of  
 44 another?" The inconsistent treatment of the costs BCH's customers would pay to  
 45 someone other B.C.Hydro when they participated in demand side management  
 46 ("DSM") initiative made this exercise more difficult than it should have been. This  
 47 was in addition to the problems associated with accounting for the differences in  
 48 amortization periods between IPP and BCH projects and other differences in the  
 49 financial methodologies used to evaluate IPP and BCH projects. These  
 50 differences will probably be settled at a BCUC hearing.  
 51  
 52

53 Page 8

54 "At the end of the question period, the IPABC Committee member to arrange a  
 55 meeting between certain IPABC directors or their designates and representatives  
 56 to discuss the details of the Burrard Plant. The Committee member advised BCH  
 57 that he wanted these directors at the meeting to provide him with the analytical  
 58 support required to properly assess BCH's proposal. The IPABC's concern was  
 59 that it's Stave Falls analysis, which was presented to the Committee, shows that

1 this project is not economic and the same might be true for the Burrard Plant. In  
 2 addition, BCH never provided an adequate response to the concerns the IPABC  
 3 raised about BCH's plans to expand the existing Burrard Thermal plant, which is  
 4 currently 30% efficient and install catalytic converters to reduce air pollution.  
 5

6 BCH advised the IPABC Committee member that he could meet with the  
 7 representatives of BCH to discuss the Burrard Plant but no one else from the  
 8 IPABC would be permitted to attend. The reason given was that BCH had  
 9 signed confidentiality agreements with some equipment manufacturers who were  
 10 assisting BCH with the re-powering proposal. As a result of being denied an  
 11 opportunity to properly examine information relating to the re-powering of the  
 12 Burrard Plant, the IPABC has no confidence in its use in computer modelling and  
 13 computer selection."  
 14

15 Page 9

16 The IPABC wants to make it perfectly clear that through its participation on the  
 17 Committee, it is not supporting or endorsing the Plan. It is BCH's plan. It  
 18 contains a number of serious technical flaws and was developed by a process  
 19 that was similarly flawed.  
 20

21 The Plan will have an impact on potential expenditures of over \$10 billion which  
 22 will be borne by BCH's customers. The IPABC does not believe that the Plan  
 23 can be used to justify expenditures of this magnitude and will be requesting the  
 24 BCUC to conduct an IRP hearing."  
 25

26 Despite amendments to the B.C. Utilities Commission Act, which according to the  
 27 IPPBC's reading, and as supported by the corresponding extract from Provincial  
 28 Hansard, provide the necessary jurisdiction to the BCUC to review the IEP, BCH is still  
 29 fighting the same battle that it did in 1995.  
 30

31 Perhaps the answer is that BCH is concerned that its long term vision of Burrard  
 32 Thermal, Site C, imports, Power Smart and Resource Smart is so fatally flawed that it  
 33 would not survive a full public review.  
 34

35 As noted by Chairman Hobbs, at TR Volume 5, page 374 *"The Commission has*  
 36 *jurisdiction pursuant to Section 45 (6.2) to establish a process to review the 2004 IEP."*  
 37 According to Exhibit A-28, an extract from the British Columbia Hansard that pertains to  
 38 the amendments to the Utilities Commission Act that were introduced to give the BCUC  
 39 statutory jurisdiction over utility integrated electricity plans:  
 40

41 "To enhance the effectiveness of the Utilities Commission, all public utilities will be required to file  
 42 resource plans. Resource plans give the commission the ability to review a utilities resource  
 43 acquisition in advance of capital expenditures. The intent of the resource-planning requirement is  
 44 to protect ratepayers from poor utility expenditure decisions, to ensure that utilities have adequate  
 45 supply to meet demand, and to protect utilities and its shareholders from costs that may have been  
 46 otherwise disallowed."  
 47

48 The IPPBC requests that the BCUC order BCH to participate in a full public review of  
 49 the IRP so that interested parties can get answers to their concerns about this IEP.  
 50  
 51  
 52  
 53

## 1 9. BCTC ISSUES

2  
3 The transmission issues the IPPBC raised during the Review such as transmission  
4 interconnection requirements and studies, availability and cost of transmission space,  
5 exports, etc. should be dealt with at upcoming BCUC reviews of BCTC. Based on this  
6 expectation, the IPPBC will hold its arguments on these and other transmissions issues  
7 until these reviews.  
8

## 9 10. ACQUISITION ISSUES

10  
11 The main issue in this area that was raised during the Review is regulatory oversight of  
12 executed electricity supply contracts between BCH and IPPs. IPPs are extremely  
13 concerned that after going through arduous and expensive competitive bidding process,  
14 (e.g. BCH's Vancouver Island bidding process which has included multiple amendments  
15 to the bidding conditions over a nine month period, and it still hasn't concluded), the  
16 contracts IPPs execute will then be subject to a BCUC review process. The IPPBC has  
17 no objection to a timely BCUC contractual review before BCH initiates a competitive  
18 bidding process. It would welcome the opportunity to discuss before the BCUC  
19 contractual issues such as flow - through of future tax increases, liquidated damage  
20 provisions, non-refundable performance fees, pricing, length of term, green premiums  
21 etc. but not after a contract has been executed. Some of these issues were raised by  
22 the IPPBC Review witness panel.  
23

24 Once a supply contract is signed, IPPs have to get on with trying to find financing that is  
25 based on the terms and conditions of this contract. Even with the benefit of an executed  
26 contract, a significant number of projects will not pass the "finance market" test. For  
27 IPPs, this is the ultimate external review process.  
28

29 Any review of contracts between IPPs and BCH should be *"upfront"* and not at the *"end"*  
30 of the BCH competitive bidding process.  
31

## 32 11. OTHER

33  
34 On the last day of evidentiary phase of the Review, Chairman Hobbs identified at least  
35 six legal issues that interested parties might address in argument. The IPPBC has no  
36 comment on any of these issues except to say that if BCH's capital structure is to be  
37 reviewed it ought to be the subject of a separate BCUC review. It is a very complex  
38 topic that may have an impact on the Province's financial accounts. The IPPBC has  
39 raised its legal arguments concerning the IEP under the headings *"Full Public Review*  
40 *by the BCUC of the IEP"* and *"Integrated Electricity Plan ("IEP")/Resource Expenditure*  
41 *and Acquisition Plan ("REAP")*.  
42  
43  
44  
45

## 12. CONCLUSION

There is no better conclusion to the IPPBC's argument than BCH's undertaking to provide a response to the following question of Chairman Hobbs TR Volume 20, pages 3583 - 3591:

"Provide an evaluation of the opportunities to more costs to F2006 by drafting reservoir levels in F2005 lower than currently planned (including, if appropriate, an analysis of the impact on BC Hydro's revenue requirements and rate application)."

BCH's answer in part is:

"...Key results of the supporting MCM study to the June Financial Undertaking are as follows:

- The median forecast level for Kinbasket (Mica) reservoir is 2,352 feet, approximately 15 feet above the historic minimum and approximately 20 feet above licence minimum.
- The median forecast level for Williston Reservoir (GMS) is 2,148.5 feet, approximately 1.5 feet above historic minimum and approximately 42 feet above licence minimum.
- The median forecast of system energy for April 2005 is near the record low storage level, with an expectation of being only approximately 1,000 GWh above the historic minimum levels at major reservoirs.

The above noted forecast is based on expected or median values. To prevent reservoir drawdown below the historic minimum levels, roughly 700 GWh of cushion (Kinbasket storage) is desirable to accommodate less than winter run-offs and/or higher than expected levels. It is not appropriate to rely on markets to address this uncertainty as expected market purchases have already been concentrated into lower-priced periods. Additional reliance on market purchases would increase the risk exposure to high market prices.

While it may be possible to create a second scenario which reduces market purchases in F2005 by approximately 300 GWh (approximately \$21 million) with a corresponding increase in F2006, BC Hydro has not developed such a scenario for the following reasons:

- Since running the above study, BC Hydro has received informal information that the Arrow Lakes return to service may be further delayed, potentially reducing the IPP's deliveries by a further 200 GWh.
- There is significant pressure to prevent Williston reservoir from drafting below 2,150 feet. Historically, the reservoir has drafted to 2,147 feet in 1989 and in 1997 with little to no adverse impact on the local industries. Nevertheless, these industries have focused on the 2,150 feet. Given the timing of the potential low elevations in 2005, there could be significant risks to the draft Water Use Plan stakeholder consensus if elevations proved unacceptable.
- The base case scenario was the direct output of the reservoir optimization. Absent the objective of leveling the cost of energy between F2005 and F2006 and of meeting shareholder expectations for the dividend, BC Hydro management may be inclined to purchase additional energy in F2005 as a

1 potential risk mitigation against the possibility of low flows in F2006. As it is,  
2 there is essentially no additional reservoir storage available to mitigate the costs  
3 and impacts of low flows in F2006.  
4

- 5 • It is no appropriate to plan to draft a major reservoir, such as Mica, right to  
6 water licence minimums because of the potential for delayed run-offs and the fact  
7 that generation would be limited to/by available inflow as this would result in a an  
8 unacceptable level of risk to system reliability..."  
9

10 The cupboard is bare. There is no drought of the type that occurred in the early 1940's  
11 and late seventies and early 1980's. The Burrard Thermal plant can't produce the  
12 energy BCH claims it can. Domestic demand is going up. There are serious constraints  
13 about drawing the Williston reservoir below 2,150 feet. The forecast cost of imports in  
14 Fiscal 2005 has risen 22% and in Fiscal 2006 27% from the forecasts contained in the  
15 December 2003 Application. The forecast volumes have risen 165% for Fiscal 2005  
16 and 192% for Fiscal 2006. And BCH claims it only needs 400 GWh of electricity from  
17 IPPs for delivery by 2009.  
18

19 BCH has ignored the "*secure, reliable supply*" cornerstone of the B.C. Government's  
20 Energy Plan. The IPPBC suggests that the BCUC should require BCH to take  
21 immediate remedial action by increasing the amount of electricity that BCH purchases  
22 from IPPs by at least 3,000 GWh and/or holding a full public hearing into BCH's IEP.  
23 Something has to be done to protect the security and reliability of BC Hydro's electricity  
24 supply.  
25  
26  
27  
28

## Appendix 1

### Comparison of Energy Policy Items and BC Hydro Decisions/Initiatives

Energy Plan Policy Actions	BCH Decision/ Initiative	IPPBC Comments
#9 Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.	Imports	<ul style="list-style-type: none"> <li>• Excessive reliance on imports to buffer BCH energy shortfalls results in lower reliability than procuring additional resources from domestic IPPs.</li> <li>• BCH has not responded to Energy Plan direction to reduce reliance on imports. In the F2005 and F2006 test years reliance on imports increases.</li> <li>• BCH has not accounted for the additional benefit of increased exports from IPP purchases.</li> </ul>
	Burrard Thermal	<ul style="list-style-type: none"> <li>• Burrard does not provide reliable or low cost energy relative to IPP contracts. Continued dependence on Burrard for planning purposes creates unnecessary reliance on imports rather than domestic IPP supply.</li> </ul>
#21 New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.	Power Smart	<ul style="list-style-type: none"> <li>• BCH has failed to model the impact of stepped rates in designing its Power Smart targets.</li> <li>• BCH is focused on Power Smart targets that will raise rates higher than would otherwise occur if it serve load growth through IPP purchases.</li> </ul>
#13 The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.	Site C, Mica and Revelstoke	<ul style="list-style-type: none"> <li>• BCH seeks approval to make expenditures for preliminary development of Site C, Mica and Revelstoke without any supporting financial analysis to support a move away from IPP contracts.</li> <li>• BCH has not responded to the Energy Plan direction to reduce the reliance on public funds to develop generation resources.</li> </ul>
	Level Playing Field	<ul style="list-style-type: none"> <li>• BCH has not addresses the unlevel playing field concerns expressed as far back a 1995</li> <li>• BCH does not use one method to fairly compare all resource options – BCH unfairly groups resources into separate categories before determining procurement objectives</li> <li>• BCH is both a project promoter (Heritage asset expansion and new site development) and resource planner fixing the quantum of IPP resource procurement.</li> </ul>

## **Appendix 2**

### **Technical Argument Regarding Power Smart Expenditures**

(See separate attached electronic file entitled IPPBC RRHearing - Final  
Argument\_Appendix2.doc)