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June 30, 2004

DELIVERED

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
P.O. Box 250
600 – 900 Howe Street
Vancouver, B.C. V6Z 2N3

Dear Mr. Pellatt:

RE: British Columbia Hydro and Power Authority ("BC Hydro")
Project No. 3698360 - Letter No. L-25-04
Revenue Requirements 2004/05 and 2005/06 Application

We enclose 20 copies of:

1. BC Hydro's Final Argument;

2. BC Hydro's response to two final undertakings for which exhibit numbers have been reserved as follows:

Ex. B1-197	June Financial Update
Ex. B1-198	Response to undertaking at T20: 3583/91 relating to an alternative reservoir operation scenario

3. A revised version of Ex. B1-190 that corrects a number of small errors. We propose the corrected version be labelled Ex. B1-190A;

4. A CD-Rom containing all the exhibits filed in this proceeding, excluding the ones filed today.

Due to discovery of a mistake in one table, BC Hydro will file its response to one last undertaking – a table reconciling the REAP capital plan with Chapter 11 of Ex. B1-1, for which exhibit number B1-199 has been reserved – on July 2, 2004.

We have electronically served all parties to the proceeding with this letter and enclosures, including the Commission.

Yours very truly,

LAWSON LUNDELL

Chris W. Sanderson, Q.C.

CWS/bts

cc: All Intervenors

cc: BC Hydro
Attention: Richard Stout

BC HYDRO
Revenue Requirements
2004/05 and 2005/06

Counsel's Final Argument
on behalf of
British Columbia Hydro and Power Authority

June 30, 2004

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EXECUTIVE SUMMARY

This Argument marks the beginning of the end of a lengthy, thorough and often painstaking review of BC Hydro's objectives and cost structure. For the first time in 10 years, BC Hydro's senior management testified under oath about their objectives and plans for BC Hydro, and the costs necessary to fulfill them. Against an evidentiary backdrop of over 13,000 pages of documents and written answers to questions, those objectives were made clear. BC Hydro will complete the implementation of those components of the Energy Plan that relate to it; as that process winds down, BC Hydro will direct increasing attention to cost efficiency; and, finally, and most significantly, BC Hydro will continue its long-standing commitment to providing safe, reliable services.

In this proceeding, BC Hydro has applied for approval of a rate increase to its bundled service customers; approval of a decrease in rates to its wholesale transmission customers; approval of the creation of certain accounts that will smooth rates going forward; and approval of its Resource Expenditure and Acquisition Plan. Each of these applications is grounded in the evidence put forward by BC Hydro and its senior executives and, in particular, in BC Hydro's focus on safe, reliable and cost-effective service. That evidence was extensively tested through cross-examination during the oral phase of this hearing and remained, in BC Hydro's submission, robust, coherent and persuasive. For the reasons elaborated on below, BC Hydro respectfully submits that it has met the onus on it, and the applications ought to be approved.

I. INTRODUCTION TO ARGUMENT

BC Hydro has four applications before the Commission in this proceeding:

- revenue requirements and bundled service rate increase
- reduction in wholesale transmission service (WTS) rates
- approval of deferral accounts
- resource expenditure and acquisition plan (REAP)

Each of these four applications has a distinctive or even unique aspect to it.

A. Revenue Requirements and Bundled Service Rate Increase

The revenue requirements and rate increase application seeks the first change in rates since 1993 and reflects the recent removal of BC Hydro's rates from the legislative freeze under which they operated until April 1, 2003. As well, this rate case represents the first review of BC Hydro's rates under Heritage Special Direction No. HC2. Heritage Special Direction No. HC2 cleans up the language previously contained in Special Direction No. 8 and expressly re-enacts some of its key provisions. In particular, it contains a reaffirmation made November 20, 2003 that the Commission is to set rates intended to ensure that BC Hydro can earn a rate of return on the sum of its retained earnings, deferred revenues, contributions arising from the Columbia River Treaty and contributions in aid of construction, which rate of return is equivalent to the rate of return that the most comparable BC utility earns on a more conventional definition of equity. Much was made during this hearing, as it was in the 1993 and 1994 rate hearings, of the definition of

equity contained in both Special Direction No. 8 and Heritage Special Direction No. HC2, but it cannot be denied that Cabinet has reaffirmed its instructions with respect to the definition of equity and has done so despite the invitation issued by the Commission in the Heritage Contract report and recommendations that Cabinet re-examine the issue.

B. Reduction in Wholesale Transmission Service (WTS) Rates

The application involving WTS rates is unique in that responsibility for WTS rates is in transition to BCTC. Accordingly, this is the last application that BC Hydro expects it will make with respect to WTS rates, and an application by BCTC to re-establish those rates under its open access transmission tariff (OATT) is imminent. In these circumstances, BC Hydro has advocated a minimalist approach to the WTS rate application.

C. Approval of Deferral Accounts

BC Hydro's application for deferral accounts is made necessary by Heritage Special Direction No. HC2, which, effective April 1, 2004, directs the Commission to allow the creation of deferral accounts regarding the Heritage Payment Obligation and Trade Income, and gives the Commission the express authority to allow BC Hydro to establish additional deferral accounts where it thinks appropriate. The rate stabilization account (RSA) is repealed effective July 1, 2004. This is the first opportunity for the Commission to consider how to exercise these powers.

D. Resource Expenditure and Acquisition Plan (REAP)

Revisions to the *Utilities Commission Act*, which became effective May 29, 2003, require the filing of additional plans relating to capital expenditures, resource acquisition expenditures and

demand side management (DSM) expenditures. BC Hydro's REAP application constitutes the first opportunity the Commission has had to review an application by BC Hydro in this regard.

These novel applications and their unique characteristics led to an extensive application and prehearing information request process and to considerable complexity associated with all aspects of the proceeding. However, BC Hydro respectfully submits that by the end of the evidentiary phase of the hearing, with few exceptions, the bulk of the assertions made in the application were fully supported by BC Hydro's evidence and were uncontradicted by evidence led by any other party during the course of the hearing. Where BC Hydro has identified its expenses, it should be allowed to recover them unless the Commission has been provided some basis to conclude they are overstated. As a recognized authority on utility regulation has said:

> There have been frequent holdings to the effect that "in the absence of a showing of inefficiency, improvidence, waste or bad faith on the part of management," a regulatory agency cannot lawfully "ignore the necessary fair and reasonable expenses of operation incurred in the rendition of service … but must … allow all such expenses constituting charges upon income …" Managerial good faith is presumed. Expenses "should be scrutinized with care," but they "should not be disallowed or reduced unless it clearly appears that they are excessive or unwarranted or incurred in bad faith." Nor can a regulatory agency, in determining the propriety of expenses, "disregard the evidence and substitute for its judgment of the evidence its judgment of what the company ought to be able to do."[1]

This quote confirms that a comprehensive review of the evidence on an item-by-item basis is neither necessary nor useful because the vast bulk of the testimony is uncontradicted. That is, as the very helpful processes pioneered by the Commission in connection with this proceeding made clear, the number of issues raised by intervenors has been quite limited. It is true that the Joint Industry Electricity Steering Committee (JIESC), in its opening, seemed to suggest that

Commission staff was charged with the responsibility to inquire in areas whether or not they had been placed in issue by any intervenors and, indeed, it is fair to say that Commission staff and the Commission Panel did at times do precisely that. However, even with the active intervention of the Commissioners, Commission staff and the intervenors, there are still huge areas where BC Hydro's evidence is uncontradicted. In these areas, we respectfully submit that the Commission must accept the evidence.

Instead, we focus in this Argument on the matters that really were contested during the course of the hearing. We do this by looking at each application separately and, within each, organizing the Argument under the following headings:

A. Role of the Commission with respect to each application (including outline of primary legal, policy or regulatory issues)

B. Legal, policy and evidentiary issues with respect to each application

C. Proposed order

At the conclusion of the Argument, in Part 6, we address any remaining legal issues which did not conveniently fall under any of the applications within the above structure. This includes comment on further processes that, while not directly relevant to this proceeding, will round out the re-regulation of BC Hydro's rates.

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[1] Priest, *Principles of Public Utility Regulation* (Charlottesville, Virginia Michie Company, 1969) at p.50 (footnotes omitted).

II. THE REVENUE REQUIREMENTS AND RATE APPLICATION

A. Role of the Commission

BC Hydro has applied for an 8.9% increase in its rates for F2005, and no increase for F2006.[2] This request is based on the information that was available to BC Hydro with which to construct a forecast on February 20, 2004. The 8.9% increase consists of confirmation of the 7.23% interim increase that has been in effect since April 1, 2004, with a 1.67% increase effective 30 days after the date of Commission's decision on this Application.

In ruling on this Application, the Commission must have regard to the requirements of Heritage Special Direction No. HC2 (HSD#2)[3] and the overall just and reasonable standard prescribed in the *Utilities Commission Act* (the Act). Pursuant to these requirements, the Commission "must ensure" that the rates that it sets for BC Hydro are sufficient to enable BC Hydro to:

> (a) provide reliable electricity service;
>
> (b) meet all of its debt service, tax and other financial obligations;
>
> (c) comply with all government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and
>
> (d) achieve an annual rate of return on equity equal to the pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*.[4]

Thus, the Commission must ensure that customers are charged the amount necessary to ensure that they can be provided the level and quantity of service the Commission determines to be

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[2] Subject to adjustment consequential upon a new allowed return on equity and effective tax rate for Terasen Gas Inc.

[3] Heritage Special Direction No. HC2 to the British Columbia Utilities Commission enacted under Sections 3 and 4 of the *BC Hydro Public Power Legacy and Heritage Contract Act*, S.B.C. 2003, c. 86.

[4] Section 4 of HSD#2.

sufficiently reliable to comply with paragraph (a), while ensuring BC Hydro is afforded an opportunity to earn the amounts set out in paragraphs (b) to (d).

In undertaking this review of BC Hydro's revenue requirement, it is important to also have regard to what this proceeding is not about.

First, it is not a hearing into whether the provisions of the Special Directions are appropriate or fair. There were many times during the hearing when it appeared that witnesses or counsel were more concerned with the equity of HSD#2 than with whether the Application of BC Hydro complied with it. However, in the end, the main intervenor witness who dealt with questions related to the interpretation of HSD#2 conceded that:

> …in a lot of the previous activity that customers have undertaken dealing with the Special Directions, they've spent most of their time challenging the definitions of the government put forward. That came up again in the Heritage hearings. I don't think that the Commission has the ability to change those. I think only the government does.[5]

BC Hydro submits that Mr. Craig is quite right. This hearing is not about the wisdom or fairness of HSD#2. Rather, it is only about whether BC Hydro's Application properly interprets and applies that regulation.

In interpreting HSD#2, there was much loose reference during the hearing to the Energy Plan. BC Hydro itself explained many of the initiatives it has undertaken over the past two years in the context of their consistency with the objectives of the Energy Plan. This is as it should be, given that insofar as it relates to BC Hydro, the Energy Plan can be viewed as a dialogue between

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[5] Testimony of Mr. Craig at T21: 3910/16-23.

government and a Crown agency. However, the legal effect of the Energy Plan on the Commission's regulatory responsibilities is quite distinct.

The law is clear that absent a government directive that is expressly contemplated by enabling legislation, the Commission cannot fetter itself by blindly following government policy. This principle was clearly established in *Innisfil (Township) v. Vespra (Township)*, [1981] 2 S.C.R. 145, which stands for, among other things, the following propositions:

1. When a statement is recognized as government policy, a tribunal should allow cross-examination on the evidence and argument upon the policy;

2. The tribunal should subsequently give whatever weight it believes the policy itself deserves. It can, if it chooses, give it no weight and, accordingly, ignore it or distinguish it;

3. If the tribunal chooses to accept the policy as representing the proper way in which to dispose of the matter before it, it is free to do so, but it is not "bound" to do so; and

4. Even if the policy is government policy, it must not be inconsistent with the objectives of the legislature governing the tribunal's authority.[6]

In this case, the Commission has permitted extensive cross-examination on and discussion of the Energy Plan. This was entirely appropriate. However, when it comes time for the Commission to exercise its authority, it must comply with the Act and HSD#2. It may have regard to the

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[6] MacAulay and Sprague, *Practice and Procedure Before Administrative Tribunals*, Looseleaf (Toronto: Thompson Canada, 2002) at 3-24.

Energy Plan, but it is not bound by it, and it most certainly may not employ the Energy Plan to override its express obligations under the Act and any regulations (including HSD#2). As elaborated later in this Argument, it would appear from their evidence that at least some of the intervenors would have the Commission ignore its obligations in this respect and interpret the Energy Plan in a way that is fundamentally inconsistent with the Act and HSD#2. With great respect, the Commission should resist this temptation.

Second, this is not a rate design hearing. Rate design issues were intentionally left off the Commission's Issues List. BC Hydro will be filing a rate design application, as explained in Part 6 of this Argument. At various times, intervenors invited the Commission to reconsider the allocation of costs between different classes of customers[7], modify the contributions required from generators interconnecting to the system and/or customers to whom the system is extended and, more generally, modify the system extension test applied by BC Hydro in determining whether to charge customers for extensions at all. All of these matters are the subject of existing BC Hydro tariffs. BC Hydro has not applied to revise those tariffs and no complaint has been filed with respect to any of them. The appropriateness of these tariffs were not defined as issues in this case. The only issues that were raised were the accounting treatment afforded to money paid pursuant to the tariff (Issue 2.3) and whether or not the system extension test was being properly applied by BC Hydro (Issue 5.6). These limitations in the Issues List are entirely appropriate, given that no complaint with respect to the tariffs themselves was made and, in consequence, no evidence on the appropriateness of those tariffs was led. Accordingly,

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[7] See Ex. C35-5, Commercial Energy Consumers of British Columbia ("CECBC") Direct Evidence of Penny Cochrane and commercial customers.

BC Hydro respectfully submits that the Commission should refrain from dealing with any of these rate design issues in this proceeding.

Third, this is not a hearing intended to place the Commission in the role of management of BC Hydro. Insofar as the Commission's powers arising from its rate setting responsibilities are concerned, the law as stated by Mr. Justice Goldie in *British Columbia Hydro & Power Authority v. British Columbia (Utilities Commission)*[8] remains unchanged:

> It is only under s. 112 of the *Utilities Act* that the Commission is authorized to assume the management of a public utility. Otherwise the management of a public utility remains the responsibility of those who by statute or the incorporating instruments are charged with that responsibility. …
>
> Taken as a whole the *Utilities Act*, viewed in the purposive sense required, does not reflect any intention on the part of the legislature to confer upon the Commission a jurisdiction so to determine, punishable on default by sanctions, the manner in which the directors of a public utility manage its affairs.[9]

The significance of the amendments to section 45 of the Act since that decision was issued are discussed in Part 5 of this Argument relating to the REAP. However, it is clear that the Commission's powers over rates were unaffected by the amendments and a clear line continues to exist between the obligation of a utility to manage so as to meet its obligation to serve and the Commission's obligation to determine how much of the resultant expense of operating its business can be recovered in rates. [10]

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[8] (1996), 20 B.C.L.R. (3d) 106 (C.A.).

[9] *Ibid* at 120.

[10] See also *Office and Professional Employees' Int'l Union et al v. B.C. Hydro et al*, 2004 BCSC 422, where Neilson, J. cited this passage with approval at paras. 18 and 63.

B. Issues With Respect to Revenue Requirements and Rate Application

1. Introduction

The issues with respect to BC Hydro's revenue requirement application fall into two broad categories. The first category includes those issues that have the effect of allocating funds between shareholder and ratepayers, or that shift costs between current ratepayers and future ratepayers. These are not issues that question spending by BC Hydro or its efficiency, but rather that involve the appropriate return, now or in the future, to BC Hydro's shareholder, and the distribution of BC Hydro's income between shareholder and ratepayers. These issues are essentially legal and/or accounting in nature, their resolution involving interpretation of HSD#2 and Heritage Special Directive No. HC1[11] (HSD#1) (collectively, the Special Directions) and Generally Accepted Accounting Principles (GAAP). The dollars at stake between shareholders and ratepayers are approximately $207 million in F2005 and $257 million in F2006.[12] As well, Mr. Craig sought to shift responsibility for some additional costs from current to future ratepayers based on some proposed accounting adjustments.

The particular issues that fall into this category are:

- the effect on BC Hydro's revenue requirements arising from the change under GAAP from Future Removal and Site Restoration (FRSR) to Asset Retirement Obligations (AROs);

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[11] Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority enacted under Section 35 of the *Hydro and Power Authority Act,* R.S.B.C. 1996, c. 212.

[12] Testimony of Mr. Craig at T21: 3973/21-3974/4.

- the effect on BC Hydro's revenue requirements arising from the definition of "equity" in HSD#2 and BC Hydro's obligation to annually pay 85% of its distributable surplus to government under HSD#1;

- the effect on BC Hydro's revenue requirements arising from contributions in aid of construction being included in the definition of "equity" in HSD#2;

- the effect on BC Hydro's revenue requirements arising from cost of energy forecasts based on known reservoir conditions; and

- the effect on BC Hydro's revenue requirements arising from depreciation and amortization rates.

The second category of issues in this Application includes the expenditure levels or efficiency of BC Hydro in terms of its proposed operations, maintenance and administration costs (OMA) and capital expenditures, cost of energy, finance charges and its related forecasts. According to Mr. Craig's estimate, the issues in this category amount to, at most, 2.2% of the applied for rate increase or $52 million.[13]

To resolve the issues relating to the first category, the Commission must effectively determine what costs are properly to be considered pursuant to HSD#2 and the Act. To resolve the issues relating to the second category, the Commission must assess the evidence relating to BC Hydro's estimate of the costs involved. Each category is discussed in turn below.

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[13] T21: 3975/15 to 3976/1; and Ex. C35-8.

2. Accounting / Legal Issues

The legislative provisions that are relevant to the accounting/legal issues are as follows:

Heritage Special Direction No. HC2 (HSD#2)

1. In this Special Direction:
"equity" means the sum of the following amounts at the end of the fiscal year:
(a) retained earnings;
(b) deferred revenue;
(c) contributions arising from the Columbia River Treaty;
(d) contributions in aid of construction;

4. Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to
(a) provide reliable electricity service,
(b) meet all of its debt service, tax and other financial obligations,
(c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and
(d) achieve an annual rate of return on equity equal to the pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*.

6. In setting the authority's rates, the commission must allow the authority an annual rate of return on equity calculated using forecast consolidated operating income, which forecast consolidated operating income is calculated on the basis of forecast trade income.

8. When regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to allocate annual distributable surpluses in the manner specified by the Lieutenant Governor in Council under section 4 of the Act or section 35 of the *Hydro and Power Authority Act*.

Heritage Special Directive No. HC1 (HSD#1)

1. In this Special Directive:
"distributable surplus" means, for a fiscal year,
(a) the consolidated net income, earned by the authority and its subsidiaries from all sources, as reflected in the authority's audited consolidated financial statements for that fiscal year, less
(b) the finance charges capitalized during the fiscal year, net of depreciation charged on capitalized finance charges;

"equity" means the sum of the following amounts at the end of fiscal year:
(a) retained earnings;
(b) deferred revenue;
(c) contributions arising from the Columbia River Treaty;
(d) contributions in aid of construction.

3. On or before June 30 of each year after 2004, the directors of the authority must cause the authority to pay to the government, for deposit into the consolidated revenue fund, an amount equal to
(a) 85% of the authority's distributable surplus for the previous fiscal year of the authority, or
(b) if the payment required under this section would result in the debt/equity ratio of the authority exceeding 80:20, the greatest amount that can be paid by the authority without causing the authority's debt/equity ratio, after the payment is made, to exceed 80:20.

Section 4(d) of HSD#2 requires the Commission to set BC Hydro's rates at a level sufficient to allow a return on equity. There is no dispute that the rate of return on equity for F2005 is 13.91%.[14]

The principal interpretive issues that have arisen with respect to the interpretation of these regulations are as follows:

- What is the significance of the requirement in HSD#2 on the Commission to ensure that all items listed in section 4 are recovered in rates?

- Can the Commission require BC Hydro to establish an account to be amortized or drawn down against actual costs that would otherwise be required under GAAP to be charged to income in connection with the elimination of FRSR accounts?

[14] The Application, Chapter 10, p.10-8.

- Can the Commission require BC Hydro to establish an account to record that portion of BC Hydro's net income that is not paid to government pursuant to section 3 of HSD#1 in a deferral account so that the Commission can later determine the application of those funds in order to reduce the amount of equity on which BC Hydro earns a return?

- Is there any other way that the Commission can determine a deemed capital structure for BC Hydro in the face of the Special Directions?

- Should the Commission re-design BC Hydro's System Extension Test so that going forward "contributions in aid of construction" would be reduced to zero?

These issues are discussed next.

a) Recovery of the items listed in section 4 of HSD#2.

As discussed above, HSD#2 is a binding direction to the Commission with the force of law.

The language of section 4 of HSD#2 makes clear Cabinet's concern that the Commission not take risks in establishing BC Hydro's rates that it would not take with another utility. The rates must be high enough to leave the Commission confident that BC Hydro will be able to recover all elements of its revenue requirement. Thus, these words require the Commission to have concluded that proposed expenditures are excessive, and are not required to "provide reliable electricity service" or to recover the other costs mentioned in section 4 before disallowing them.

In this respect, BC Hydro relies on the specific words of HSD#2, but this position is not inconsistent with usual regulatory practice.[15]

b) Proper accounting treatment to eliminate FRSR accounts.

There was a significant amount of testimony relating to the appropriate accounting treatment for what were formerly known as FRSRs, which, due to a change to the GAAP accounting rules, must now be treated as AROs. The issue is that prior to the GAAP change, BC Hydro was required by then existing GAAP to record a cost each year on its books to reflect the anticipated future site removal and restoration costs associated with a number of its assets. Until and including F2004, BC Hydro accordingly recorded some $244 million of costs in this respect.[16]

The JIESC, in its opening and through its witness, Mr. Johnson, and the CECBC, through Mr. Craig, asserted without analysis that BC Hydro had been collecting from customers an amount for FRSR over the past 10 years. These assertions significantly overstate and oversimplify the relationship between rates and underlying costs. Rates may be developed and approved with reference to underlying costs, but, once approved, stand on their own as the only legally enforceable charge a utility may make for its services.[17] The costs that give rise to this rate will inevitably change over time, but the reasonableness of the rates depends on whether the gross revenue they generate is expected to generate the gross revenue requirement of the utility. There is no ongoing linkage between any particular cost component and particular rate levels. In short, it is not possible to say customers have already "paid for" any element of costs.

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[15] See Priest, *supra*, note 1.

[16] The Application, Chapter 2, p.2-18, Table 2-14.

[17] Act, s.61(3).

In the context of this Application, the disconnect between specific costs and BC Hydro rates is particularly apparent.

Since 1994, there has been no material impact of changes in any costs on customer rates. That is, because BC Hydro's rates were effectively frozen for most of that period, there really was no connection between BC Hydro's costs, on one hand, and the rates customers paid, on the other.[18] Rates were not set to recover costs. Rather, rates were maintained at a constant level and the foreseeable result was that in some years, BC Hydro underearned its revenue requirement while in others it greatly overearned.[19] The government of the day dealt with these overearnings by either permitting the RSA to grow to ameliorate the need for further rate increases or by ordering a special dividend to be paid to all residents of British Columbia.[20] The result was a disconnect between expected costs and rates.

Thus, in the context of the FRSRs, it is respectfully submitted that there is not a real equity issue – as explained above, it is simply not possible to say that over the past 10 years ratepayers have paid any particular cost because of the absence of a rate-making methodology based on cost. The double counting argument raised by JIESC and CECBC is a red herring.

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[18] BC Hydro's rates were set by the legislature from January 1, 1996 (for residential rates, expressed as a cap), and December 10, 1997 (for all rates, expressed as the only lawful, enforceable and collectable rates that BC Hydro could collect) continuously to March 31, 2003. The legislative history of the rate freeze is as follows: *Tax and Consumer Rate Freeze Act*, S.B.C. 1996, c. 17, s. 2; *British Columbia Hydro and Power Authority Rate Freeze and Profit Sharing Act, 1998*, c. 4 and *B.C. Reg. 190/98*; *Budget Measures Implementation Act, 2000*, c. 22, s. 99; *Miscellaneous Statutes Amendment Act (No. 2) (2001)*, S.B.C. c. 43, s. 24.

[19] See Ex. B1-11, BC Hydro response to JIESC IR #1.22.0(b).

[20] For example, in F2001 BC Hydro had record income of $1,418 million, or $859 million after finance charges. The government responded before fiscal year end with *Special Directive No. 5*, requiring BC Hydro to pay the equivalent of $200 to every residential customer, a total deduction from income of $310 million. A further transfer to the RSA of $103 million reduced BC Hydro's net income to $446 million ($859 - $310 - $103 million), yielding an allowed ROE of 16.59% and increasing the RSA balance to $232 million.

Perhaps more fundamentally, the ARO debate is really no different than the contributions in aid of construction (CIAC) debate of 10 years ago. That is, the government knowingly re-enacted a special direction on November 20, 2003 that had the effect of including in equity the amounts that had previously been recorded as FRSRs, but were not properly AROs under the new regime. The government was made aware of this consequence, but enacted HSD#2 nevertheless.[21] In that environment, it is clear that the definition of equity is intended by government to produce what it believed was a fair return to it for its investment in the public enterprise carried on by BC Hydro.

The government's investment in BC Hydro and guarantee of its debt provides substantial benefits to all BC Hydro ratepayers and, under the legislative scheme governing BC Hydro, it is up to government to determine what compensation it should receive for the contribution that it makes. For example, in Manitoba such compensation is recognized, in part, in a guarantee fee of 95 basis points.[22] Given BC Hydro's level of debt, the absence of such a fee is a substantial savings to customers. In the end, the return that government requires is not something that can be usefully analyzed before the Commission. It is what it is and the Commission is required simply to accept it as a given in determining the revenue requirement of BC Hydro.

BC Hydro respectfully submits that Mr. Johnson's testimony that there was room to employ different accounting treatment for the removal of the FRSR balance from its balance sheet upon implementation of AROs because the specific rules relating to the treatment of the current

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[21] T6: 698/15-21.

[22] Ex. B1-185.

provision for FRSRs were not italicized[23] does not reflect good accounting practice – it certainly flies in the face of the clear words of CICA Handbook Section 1100, paragraph 13[24]. Rather, this approach reflects what Mr. Johnson thinks is good ratemaking principle, which he would prefer to apply over good accounting principle.[25] Mr. Johnson and the JIESC have been steadfast in resisting the notion that the government should use a definition of equity that is different in any respect than that which applies to other utilities. In consistently making this argument, they ignore the benefits that ratepayers receive but do not otherwise pay for. More importantly, they ignore the fact that under the legislative scheme governing BC Hydro's rates, it is the government's right to determine the manner in which its return will be calculated.

As Mr. Elton conceded, in a less prescriptive environment the entire accounting debate might have been different.[26] However, that is not the world in which BC Hydro had to apply CICA Handbook Section 3110, and it is not the world in which the Commission is called upon to make this decision. Accordingly, the accounting treatment fully described by Ms. Hardy and applied by BC Hydro should be applied in determining BC Hydro's equity and, therefore, the amount it should be permitted to earn to comply with HSD# 2.

c) Proposal to establish a deferral account in relation to BC Hydro's retained earnings.

Mr. Craig provided a very brief description of a scheme to introduce a minimum debt to equity ratio that the Commission should recognize in BC Hydro when determining its revenue

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[23] T20: 3614/11-16.

[24] Ex. B1-176.

[25] T20: 3618/11-17

[26] T7: 982/4-14

requirement.[27] Mr. Craig staunchly maintained that he recognized that the Commission was obliged to apply HSD#2, but that placing a cap on equity was not inconsistent with that obligation.

In BC Hydro's respectful submission, there is, in fact, no way to reconcile Mr. Craig's scheme with HSD#2 nor is there any way to reconcile Mr. Craig's scheme with the most elementary principles of ratemaking. Mr. Sherlock's testimony makes this clear.[28]

During cross-examination, it became apparent that what Mr. Craig intended was for the Commission to dictate, for ratemaking purposes, that BC Hydro not be allowed to retain on its books as retained earnings that portion of the net income it actually earns which was not paid to government as a dividend pursuant to HSD#1. Rather, Mr. Craig would have those monies appropriated from BC Hydro for the purpose of later application to ameliorate contributions to BC Hydro's future revenue requirement that customers would be called upon to make. The flaw in this scheme is fundamental.

This Commission, like all regulatory commissions of its type, regulates rates prospectively. It has no jurisdiction to require a utility to give back to ratepayers earnings from charging approved rates anymore than it has the jurisdiction to impose on ratepayers rates designed to compensate a utility for losses in previous periods.[29] Put another way, the Commission has jurisdiction to set the price of the services provided by BC Hydro. It does not have jurisdiction to appropriate for

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[27] Ex. C35-8, p.7.

[28] T8: 1177/19-1178/8; T9: 1238/19-1239/23; T10: 1433/15-1434.17.

[29] The B.C. Court of Appeal has held that the Commission's balancing of interest "was done and completed when it settled the rate base, fixed the rate of return and determined the costs of operation allowable for rate-making purposes." *Hemlock Valley Electrical Services Ltd. v. BCUC* (1992), 66 B.C.L.R. (2d) 1 (C.A.) at 21. It follows

the benefit of future ratepayers income earned by BC Hydro by charging the prices the Commission has set. Mr. Craig's scheme would have precisely this effect.

Mr. Craig's scheme would also contradict Section 8 of HSD#2, and HSD#1. As demonstrated in Exhibits B1-76 and B1-40, the growth in BC Hydro's equity is a direct function of the operation of HSD#1 and HSD#2.[30] Neither BC Hydro nor the Commission has discretion in determining the pace of that growth. What Mr. Craig would have the Commission do flies directly in the face of HSD#2 and is simply a scheme to deprive government of a return calculated using the mechanism that it has determined to be appropriate. Mr. Craig would have the Commission do something that is entirely beyond its authority.

d) The jurisdiction of the Commission to deem a capital structure for BC Hydro.

Again, as demonstrated by Exhibit B1-76, the derivation of BC Hydro's capital structure is mechanistic in accordance with the Special Directions. There is no way that BC Hydro, in its discretion, can alter the mechanics of the Special Directions and no way that the Commission can either. Mr. Craig conceded this.[31] In this respect, the Commission's jurisdiction to determine the capital structure of BC Hydro is quite unlike the jurisdiction it has with respect to an efficient capital structure for other utilities it regulates.[32]

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that the Commission cannot order that the profits earned by charging those rates should subsequently be expropriated from the utility.

[30] In the table on page 6 of Ex. B1-40, the line "D/E Ratio (GAAP)" shows BC Hydro's debt/equity ratio under GAAP, assuming HSD#1 and HSD#2 did not exist. The debt/equity ratio under GAAP has been approximately 80/20 since 2001. The line below that, "D/E Ratio (Regulatory)", shows BC Hydro's equity under HSD#1 and HSD#2.

[31] T21: 3917/5-3919/1.

[32] Ex. A-35 and Ex. A-37.

Further, or in the alternative, even if the Commission had jurisdiction to determine BC Hydro's debt/equity ratio, which it does not, there is no evidence on the record of this proceeding that would permit it to do so. The JIESC failed to lead any evidence on this point and the casual survey of Manitoba Hydro as a sample of one by Mr. Craig hardly constitutes the sort of analytical evidence required by regulatory bodies to determine a capital structure.[33] There is simply no basis on which the Commission could attempt to vary the equity component of BC Hydro in this case.

e) The system extension test and contributions in aid of construction.

A number of intervenors raised the possibility of circumventing the growth in contributions in aid of construction by altering the provisions of the system extension test so as to remove the need for contributions in aid. This is wholly inappropriate for a number of reasons.

First, it is yet another attempt to subvert the clear intention of the Special Directions.[34] BC Hydro, in bringing this application, has sought to serve the Special Directions, not frustrate them. In BC Hydro's respectful submission, as a matter of law, the Commission is required to do the same. The intervenors are asking it to do the opposite.

Second, from a process point of view, the only way to vary the contributions made under the System Extension Test is to vary Commission Order No. G-80-96 and BC Hydro's tariff book at pages A-5 and A-5-2. No party has applied to do either of these things and the appropriate parties have not been put on notice that such a change is contemplated. It would be an egregious denial of natural justice to vary the System Extension Test without appropriate notice.

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[33] T21: 3934/24-3935/23.

In addition to the five issues relating to the interpretation of HSD#2 that affect the level of return that the shareholder will be permitted to receive from BC Hydro's operations, Mr. Craig makes two arguments that, if accepted, would shift the revenue requirement burden away from today's ratepayers and onto those of the future. The first has to do with the reservoir levels that are used for the purpose of calculating BC Hydro's current rates. The second is the depreciation rates which are used in connection with various BC Hydro assets. Each of these issues is dealt with below.

f) Assumed reservoir levels for calculating current rates.

BC Hydro has based its Application on snowpack and reservoir condition information that was available for use on February 20, 2004.[35] It has taken this information and used a forecast of average weather conditions going forward to yield future streamflows that it can expect to experience for the balance of the test years. In his testimony, Mr. Craig suggested that instead, BC Hydro should use normalized streamflows and reservoir conditions as the starting point and thereafter.

In BC Hydro's respectful submission, its proposal is appropriate because it applies the general principle that the facts that are known should be taken as they existed at February 20, 2004 for all variables and then future events should be forecast with as much accuracy as possible to derive the revenue requirement. Because weather is unpredictable, an average historical basis for future weather and resulting streamflow conditions is appropriate. To start with artificial

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[34] Mr. Craig was clear at T21: 3940/1-3941/12 that his objective was to find an alternative solution to see contributions in aid of construction treated differently than they are at present under HSD#2.

[35] The appropriateness of the February 20, 2004 perspective is fully discussed below.

snowpack and reservoir levels based on averages is to introduce a known and unnecessary false assumption when determining BC Hydro's rates.

Mr. Craig's proposal and its impact on BC Hydro's Heritage Deferral Account is discussed in Part 3 of this Argument, below. The key point here is that the effect of Mr. Craig's scheme would be to foreseeably shift responsibility for a portion of BC Hydro's revenue requirement from its current customers to its future customers. In BC Hydro's view, this is a generational inequity for which there is no justification in the evidence.

g) Depreciation rates

Mr. Craig also suggested adjusting depreciation rates for a number of assets. In every case, his suggestion was to extend the write-off period, thus reducing depreciation expense in current years and extending the collection of this expense over a longer period.[36] From BC Hydro's point of view, so long as the depreciation rate used to determine rates is the same depreciation rate used to determine net income, BC Hydro is not immediately affected. Of course, artificially low depreciation rates increase the risk of stranded costs if undepreciated assets come to the end of their useful life to the potential prejudice of the shareholder. Nevertheless, the major issue, again, is between BC Hydro's current and future ratepayers.

In these circumstances, BC Hydro's approach is to use sound accounting principles based on the particular characteristics of the assets in question. Mr. Craig appears to be advocating a "choice" of depreciation rate based on current customer preferences.[37] Since it goes without saying that future customers will wish that a different "choice" was made than that recommended by

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[36] Ex. C35-8, pages 10, 11, 12 and 13.

[37] T21: 3945/22-3946/21.

Mr. Craig, ostensibly on behalf of customers now, BC Hydro strongly submits that the Commission should make its "choice" based on the evidence relating to the useful life of the assets in question. Based on the evidence in this hearing with respect to each of the areas listed by Mr. Craig, the overwhelming preponderance of testimony and written evidence, culminating in Ex. B1-104, supports the depreciation periods identified by BC Hydro in its Application.

On the same topic, the Commission asked whether the test suggested in the Bonbright text is applicable to the determination of the deprecation rate for the Burrard Generating Station.[38] The answer is, in BC Hydro's submission, "no". Burrard is not out of service, but continues to provide VAR support and capacity; has in recent memory been used to generate energy (providing significant value to ratepayers); and is capable of being used for energy within a very short period of time. Its current configuration is solely to reduce costs.[39] Moreover, the principle described in Ex. A-50 is clearly made and applicable in the circumstances of a rate base regulated utility, where rate base is the depreciated capital cost of facilities used and useful and upon which a return on equity may be earned. In such circumstances a change in depreciation rates of an asset may be consistent with a removal from rate base of that asset, but those circumstances do not exist in BC Hydro's case.

3. OMA, Capital Expenditures, Energy Costs, and Finance Charge Issues

The application of HSD#2 in the specific context of BC Hydro's planned OMA and capital expenditures is relatively straightforward and does not significantly change the review standard otherwise applicable under the Act, and in accordance with regulatory practice, as summarized

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[38] Ex. A-50, T21: 3994/6-10.

[39] See for example T20: 3481/5 - 3482/23; T20: 3460/1-11.

by Priest.[40] In addition, the legal significance of the words "must ensure" in Section 4 of HSD#2 was canvassed in the previous discussion of Accounting/Legal Issues, and is equally applicable to the expenditure and forecasting issues.

A number of provisions of the Act, set out below, provide guidance to the Commission with respect to the objectives both of BC Hydro and the Commission in considering where BC Hydro ought to be focussing its efforts:

> **Commission may order improved service**
>
> 25 If the commission, after a hearing held on its own motion or on complaint, finds that the service of a public utility is unreasonable, unsafe, inadequate or unreasonably discriminatory, the commission must
> (a) determine what is reasonable, safe, adequate and fair service, and
> (b) order the utility to provide it.
>
> **Public utility must provide service**
>
> 38 A public utility must
> (a) provide, and
> (b) maintain its property and equipment in a condition to enable it to provide,
> a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.
>
> **Supervisors and inspectors**
>
> 37 (1) If the commission considers that a supervisor or inspector should be appointed to supervise or inspect, continuously or otherwise, the system, works, plant, equipment or service of a public utility with a view to establishing and carrying out measures for
> (a) the safety of the public and of the users of the utility's service, or
> (b) adequacy of service,
> the Commission may appoint a supervisor or inspector …

From the foregoing examples it is clear, in BC Hydro's submission, that the provision of safe, reliable and cost effective service ought to be BC Hydro's paramount objectives, and those of the

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[40] See Priest, *supra*, note 1.

Commission as well.[41] Moreover, consideration of these objectives ought to inform the Commission's assessment of the evidence. The evidence is discussed in the following subsection focussed on the primary matters in controversy.

(a) The Appropriate "Evidentiary Cut-Off Date"

One of the important issues that arose in the course of the hearing was the appropriate "evidentiary cut-off" date. This issue first arose at the pre-hearing conference on January 14, 2004, when BC Hydro proposed an evidentiary cut-off date. Information filed at (or before) the evidentiary cut-off would be "the information which will form the final basis for the actual hearing itself and hopefully thereby prevent constantly updating the information, which leads to confusion for everyone".[42]

Mr. Wallace on behalf of the JIESC endorsed the idea of an evidentiary cut-off date,[43] as did Mr. Gathercole on behalf of the BC Old Age Pensioners Organization et al (BCOAPO) (implicitly, in the context of a discussion regarding the need for a further round of Information Requests if BC Hydro's forecasts were to change).[44]

Arising from the January 14, 2004 pre-hearing conference was Commission Order No. G-7-04 establishing the regulatory timetable. The final paragraph in the cover letter to the order refers to Mr. Sanderson's submission on the point, and states that BC Hydro (and BCTC) ought to file final updates to its financial schedules by February 20, 2004.

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[41] The importance of reliability is also reflected in its express inclusion in Section 4(a) of HSD#2.

[42] T1: 12/21-24.

[43] T1: 23/13-24/16.

[44] T1: 34/21-35/3.

The issue seemed resolved to BC Hydro, and indeed it was not raised at the second pre-hearing conference and only came up again after the oral phase of the hearing had commenced.[45] In the latter instance BC Hydro took the position, which it reiterates here and which is consistent with Order No. G-7-04, that for the purposes of forecasting costs and revenues in future fiscal periods an "evidentiary cut-off" is essential to ensure coherence and fairness.

Coherence demands an "evidentiary cut-off" because there is simply no principled way to choose the cost and revenue items that should be updated based upon the best, most current information for a utility whose operations are as large and complex as those of BC Hydro. With over 4,100 employees across the Province, exposure to a very volatile hydrograph and wholesale electricity markets, and an ageing electrical system, BC Hydro's plans must inevitably change on a day to day basis. While many changes will be self-evidently significant and many will be small and appear unimportant, the latter may readily be significant on an aggregate basis. Moreover, picking some revenue and cost items for last-minute updating, but not others, will inevitably result in a mish-mash of forecasts, assumptions, and best-efforts that simply do not amount to a forecast. The June Financial Undertaking filed with this Application provides a perfect example in the use of adjusted F2005 and F2006 "load forecasts".[46] As articulated in the June Financial Undertaking, the original F2005 and F2006 load forecasts in the Application adjusted for actual F2004 year-end loads is no forecast at all.

Fairness also demands an "evidentiary cut-off", as is apparent from the attached June Financial Undertaking and the submissions of intervenors at the first pre-hearing conference. The June

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[45] See, for example, T8: 1076/15-22; T15: 2579/14-24; and T19: 3442/4 to 3446/12.

[46] June Financial Undertaking, filed concurrently with this Argument.

Financial Undertaking – based upon updates to an essentially arbitrary set of cost and revenue items[47] – would, if accepted, require the Commission to increase BC Hydro's rates for F2005 not by 8.9%, but by 12.7% (and then reduce them by 1.55% in F2006).[48] No intervenor has had an opportunity to examine these figures, either through the Information Request process or through cross-examination, or to cross-examine on what other updates might be feasible or (from their perspective) desirable. Their inclination to consider which if any information ought to be updated need not be inferred, but was stated on the record at the first pre-hearing conference when the issue arose.[49] It follows that using the June Financial Undertaking as the basis for F2005 and F2006 forecasts would be manifestly unfair and significantly undermine the integrity of this process.[50] Moreover, these problems associated with the June Financial Undertaking are merely illustrative of the problems that will occur with any sort of last minute update. For these reasons BC Hydro urges the Commission to confirm its earlier decision to establish February 20 as the evidentiary cut-off date, and admit evidence after that date only for the purpose of testing the veracity of the February 20 forecasts.

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[47] The June Financial Undertaking updates the February 20 forecasts in three areas, namely changes consequential upon the F2004 financial statements being finalized, including the effect of the provision for GSX costs; changes to the forecast factors that were updated between the Application and February 20, where new information was available; and changes consequential upon using the "adjusted" F2005 and F2006 load forecast. See T20: 3448/1-22.

[48] To be clear, BC Hydro is not proposing an amendment to its Application based on the June Financial Undertaking, and is not seeking a rate increase of 12.7%.

[49] See T1: 23/13-24/6 and 34/21-35/3.

[50] Note that one change in BC Hydro's forecasts as reflected in the June Financial Undertaking was known, in part, prior to February 20, 2004. That is the decrease in amortization of $2 million and $4 million in F2005 and F2006, respectively (page 12 of June Financial Undertaking). That decrease was the result of the February 17, 2004 budget meeting referred to at T10: 1500/12-1502/12. In light of the almost negligible effect on BC Hydro's revenue requirements and the fact that the adjustment to that capital program wasn't finalised until May 12, 2004, BC Hydro proposes no change to its Application.

(b) Dealing with the Massive Record

BC Hydro's views on the effect of Section 4 of HSD#2 and standard regulatory practice under the Act parallel and reinforce its views on how the Commission must assess the mountain of evidence before it in this proceeding. As BC Hydro had not been rate-regulated in ten years, it was perhaps inevitable that the volume of material would be as overwhelming as it has been. With some 13,000 pages of prefiled evidence, 19 volumes of transcript and over 150 exhibits filed by BC Hydro alone during the hearing, there is an enormous amount of evidence for the Commission to sift through in attempting to determine whether BC Hydro's planned expenditures are prudent, and its forecasts accurate.

As discussed in the Introduction to this Argument, this section will only discuss the oral evidence where some controversy is apparent. For all other matters, BC Hydro relies on the Application itself and its responses to Information Requests and undertakings.

(c) Objectives of Management

Where particular expenditures or forecasts by BC Hydro were challenged in cross-examination or intervenor evidence, it is BC Hydro's submission that the first line of inquiry the Commission should embark upon is whether or not BC Hydro's management objectives are appropriate in light of the objectives of the Act and the mandate of the Commission. In this respect, we respectfully submit the evidence is overwhelming that the objectives of BC Hydro are appropriate. That is, BC Hydro is clearly committed to providing safe, reliable service at the lowest long-term cost possible, consistent with providing its shareholder with the returns specified in HSD#2. Mr. Elton and all of BC Hydro's senior executives made it clear that those are the objectives of BC Hydro, and BC Hydro respectfully submits those are the proper objectives of the Act, and the mandate of the Commission, as described above.

This alignment of objectives makes the Commission's task much easier. In particular, where BC Hydro is managing to meet appropriate objectives, there is no place for arbitrary cost disallowances, or the arbitrary rejection of revenue or other forecasts. Any such disallowances must be reasoned and rooted in quantitative evidence. That evidence can be from qualified intervenors or BC Hydro witnesses, but in either case must identify more effective methods that BC Hydro could employ, and the net cost effect arising from the use of those methods. Only in those circumstances should the Commission substitute its views on the prudency of expenditures or the veracity of forecasts in respect of objectives that the Commission is also charged with serving.

In this section, BC Hydro demonstrates that on the evidence the objectives of BC Hydro and the Commission are aligned, and that there is no basis for arbitrary cost disallowances, or the arbitrary substitution of BC Hydro forecasts with those of intervenors or the Commission. In the subsequent subsections BC Hydro demonstrates on the evidence that appropriate mechanisms are in place to ensure that BC Hydro will continue to deliver safe, cost-effective, reliable electrical service, that no better mechanisms were demonstrated by any intervenor, and that no identifiable cost savings or more accurate forecasts were put in evidence.

BC Hydro's overriding objectives are to provide, on a long term basis, safe, cost-effective and reliable service consistent with predictably delivering its legislated return to its shareholder. This is apparent in part from the Application where BC Hydro identifies the significant cost pressures that have resulted in the applied-for rate increase. These cost pressures relate directly to reliability (increases in the cost of energy, including demand side management spending; increases in maintenance and capital expenditures; and increased costs related to transmission services) and long-term cost effectiveness (including increases in environmental and First

Nations costs).[51] The objectives of providing safe, cost-effective and reliable service, and BC Hydro's commitment to meet those objectives, are also reflected in the four key objectives of BC Hydro's Service Plan:

> GOALS AND OBJECTIVES
>
> Strong Financial Performance - optimizing financial performance to ensure stable earnings.
>
> Quality Service - focusing on customer satisfaction and service reliability.
>
> Good Environmental and Social Performance - by continuing to manage priority environmental and social issues.
>
> Skilled Workforce, Safe Workplace - ensuring that the right people are in the right roles at the right time.[52]

With respect to BC Hydro's financial objectives, Mr. Elton testified that:

> All right, I think first we have two basic objectives in financial terms, and I've talked about these already. One is to have low rates and the other is to have return for the shareholder that's acceptable, and "acceptable" for us is very much a defined term. It's defined by that special direction. And so we have to find the right balance in our activities to make sure we achieve that.[53]

Mr. Elton's focus on two objectives in financial terms distinguishes BC Hydro from investor-owned utilities. For BC Hydro, low rates are an end in themselves. For an investor-owned utility, they are not. There are three reasons that BC Hydro views the traditional conflict between the interests of the shareholder and the ratepayer differently than most other utilities:

- the shareholder represents all BC citizens, most of whom are also ratepayers;

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[51] See the Application, Chapter 1, pp.1-8 to 1-9.

[52] Service Plan, Ex. A-38, at p.21. Mr. Elton testified at T6: 669/17-25 that overall corporate objectives are enshrined in the Service Plan. At p. 12 of the Service Plan, low electricity rates are described as one of the parameters that guide decision-making in the company.

[53] T6: 716/6-13.

- the manner of regulation provided through HSD#2 separates returns to the shareholder from the level of equity invested by BC Hydro in the capital of its business, and because BC Hydro's return is not based on its rate base, it has no reason to over-invest in capital; and

- any uncertainty about BC Hydro's objectives has been removed by the fact that its shareholder has made low rates a cornerstone of its Energy Plan.[54]

As stated on page 12 of BC Hydro's Service Plan for F2005-F2007, low electricity rates are one of the four parameters that guide all decision-making within the company.[55] In addition, BC Hydro endeavours to provide a predictable return to its shareholder, as illustrated by the financial goals and objectives in the Service Plan, that emphasizes "optimizing financial performance to ensure stable earnings." [emphasis added]

BC Hydro resolves the tensions between ensuring a dividend to its shareholder that meets the requirements of HSD#2 while maintaining rates that are as low as possible by forecasting as accurately and neutrally as possible. While forecasts will never be precisely accurate, BC Hydro is as concerned to avoid underestimating net income (meaning rates were higher than they need to be) as it is to avoid overestimating it (meaning rates were not high enough).

More generally, regarding BC Hydro's long-term perspective on cost-effectiveness, Mr. Elton testified that:

> … Going forward as a matter of principle, I believe that we at B.C. Hydro have to strike -- continue to strike the appropriate balance

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[54] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.3.

[55] Service Plan, Ex. A-38.

> between the environmental, social and financial bottom lines. This is not a question just of altruism, it's a question of good business. Meeting our responsibilities today in a cost-effective manner within our control will produce cheaper solutions for us and for our customers than neglecting our responsibilities in the short term, only to have more expensive solutions imposed us in the long term. To strike this balance appropriately, we will focus on four key areas: customer service, reliability, financial performance, and people, and I'll deal with each of those now.[56]

The balanced approach described by Mr. Elton is evident in the goals of the lines of business and service organizations.

Ms. Farrell while on Panel 1 gave an excellent example of the Generation line of business's focus on cost-effective service over the long-run through its goal of providing Heritage Energy to the Distribution line of business, for less than $25.00 per megawatt hour. She testified:

> … the discussions that we had at the Heritage Contract, where we laid out for the Commission what our projection of costs would look like over ten years, and I think in that hearing we made the case that we felt that the Heritage Contract was in the order of $25. And what we've done for the generation group is we've set that as a target, in terms of if we can over the next ten years absorb costs that we see coming on Aboriginal issues, sustainability issues and increase maintenance, increased dam safety, if we can find a way to do that for under $25, we believe that that will really serve British Columbians.[57]

Mr. Maniago testified to the importance that BC Hydro places upon safety issues, the reasons for that emphasis, and explained how that process has resulted in a significantly better safety performance in recent years:

> … In the case of safety, it isn't really about the dollars. The incentive really is to make sure that people aren't getting hurt. That's really what it boils down to, and that's why you'll see in our strategies that it is in fact safety first for us.

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[56] T5: 467/9-22. See also T5: 476/21-477/21; T5: 484/16-485/3; T6: 674/22-675/18; T6: 735/8-736/1.

[57] T5: 478/24-479/25.

> What I was trying to articulate is that several years ago, we had something like 140 people hurt over a 12-month period, and we had reduced that down to about 70 in the last -- or as of the year ending March 31. This is a passion of mine, around making sure that people don't get hurt, so I want to make that very clear.
>
> … I would say absolutely, that by having a very good safety performance there are many positive outcomes, the first of which is less people hurt. But clearly, if you don't have injuries, that is a sign, I think, that the work is being done very well and attention is being paid to detail, and as a result, productivity would follow as well in terms of how well we do the work and the completion of that work.[58]

Ms. Van Ruyven on Panel 5 testified extensively to the objectives of the Distribution line of business with respect to reliability, and in particular the importance of bringing BC Hydro's reliability levels back to those it has historically experienced, as informed by customer expectations. She was very clear in articulating BC Hydro's position that it was not seeking to increase reliability at any cost, but rather to restore BC Hydro's historic levels.[59]

Finally, the BCTC witnesses also provided extensive evidence with respect to BCTC's overarching objectives of reliable, cost-effective service. Mr. Mansour neatly summarized BCTC's focus in this passage:

> … so in that respect, reliability is second to safety in our programs. We would not cut it unless it saved - if it saves money it definitely does not compromise our commitment to reliability. So again I repeat that our commitment is maintain the level of reliability and safety at lowest cost, and we'll always be able to demonstrate that.[60]

All of BC Hydro's witnesses were cross-examined extensively on management objectives, but in BC Hydro's respectful submission, none of the evidence elicited by such cross-examination can be the basis of an argument that BC Hydro's objectives are not entirely consistent with those of

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[58] T11: 1607/21-1608/6; and T11: 1609/15-22.

[59] T16: 2661/17-2662/12, and T15: 2446/21-2452/15.

the Act, and therefore by extension those of the Commission. Reliability, safety, and cost-effectiveness in the expanded sense described above were constant themes throughout the oral phase of the hearing, and indeed the written phase of the hearing as well, and together provide the canvas upon which all other actions of BC Hydro in the test periods are painted. In BC Hydro's respectful submission, there is simply no basis on the record for the Commission to come to any other conclusion. It follows that across-the-board disallowances in whole or part are completely unjustified.[61]

(d) Mechanisms to Achieve Objectives

There is extensive evidence on the record with respect to the various mechanisms BC Hydro is employing and will continue to employ to achieve its objectives. Intervenors did not generally allege that these mechanisms were imprudent or suggest alternative mechanisms that would achieve greater efficiencies, let alone attempt to quantitatively assess the dollar value on any such alternatives. What follows is a brief elaboration of some mechanisms BC Hydro (and BCTC) have in place that ensure that BC Hydro's objectives will be achieved.

First, it is necessary to be clear about where BC Hydro is in the process of restructuring, and in particular the creation of BCTC, the establishment of the lines of business model, and outsourcing to Accenture Business Services (ABS). Mr. Elton made it clear that although there has been a significant amount of energy put into restructuring, that effort is winding down and

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[60] T17: 2955/14-2955/20. See also T17: 2915/16-2919/3.

[61] Mr. Elton in his testimony also described why across the board cuts are inappropriate in a public utility context. At T6: 733/21-734/7: "So I think it's true, and I would never deny it, it's possible to achieve significant short term reductions in unit costs in any business, but first you sometimes have to do that using methods that are just not open to us because we can't sell assets. Again going back to the Heritage Asset issue that we have. And we can't choose not to serve customers. We can't say, here is a part of our business where, you know, we could just not serve those customers and save a lot of costs. That would reduce our unit costs. Those are the kinds of things that you do in the private sector in a business where you don't have an obligation to serve. We can't do that."

BC Hydro is re-focussing its resources on achieving its specific objectives, and in particular its objective of long-term cost efficiency. For example:

> … I am saying that in the long term, I believe that given the amount of restructuring we've just been through, given the amount of effort we've been putting on that, being very frank, that as we get through that, because I believe that the restructuring we've done has been well done, because I believe that you will then get an extraordinary amount more focus on, if you like, operational issues versus restructuring, on implementation versus setting up, I believe that will lead to opportunities. So it's more than just, I think, a general statement that I believe we have to do that. It's a belief just based on what I've learned about the organization, a belief that those opportunities are there, and frankly, a belief in talking to the other people that are running parts of the organization that they believe the same thing.[62]

One of the most important mechanisms BC Hydro is employing to achieve its objectives is the line of business structure. As stated in the Application, BC Hydro believes that:

> The line of business model allows BC Hydro to meet its objectives by rewarding superior performance through clear accountabilities and focus. Indeed, the overall purpose of the line of business structure is the maximization of value - the realization of the most economic trade-off between low cost electricity; secure, reliable electricity supply; increased private sector opportunities in wholesale electricity supply markets; and environmental and social responsibility. It does so by making it easier to measure and reward superior performance through clear accountabilities within the major business units.[63]

There was no serious challenge to BC Hydro's assertion that the line of business structure is an appropriate vehicle to deliver on its objectives.[64]

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[62] T5: 490/9-24.

[63] The Application, Chapter 1, p.1-17/26 to p.1-18/3.

[64] Some specific ways in which the line of business structure will deliver its intended objectives are set out in the transcript as follows: T14: 2370/11-2372/4; T20: 3570/4-3571/16; and T20: 3572/17-3573/7.

One of the specific ways in which BC Hydro will align employee performance with its corporate and line of business unit objectives is the use of a variable pay plan. The essence of the variable pay plan was described by Ms. Webb:

> Because we are linking employees' behaviour with our service plan and our commitment, and we think that having a variable pay for all employee groups helps incent that behaviour.[65]

No party took issue with the appropriateness of BC Hydro's variable pay plan, and there was no quantitative evidence in support of any other type of compensation scheme.[66]

Another significant mechanism BC Hydro has already begun to and will continue to explore is the use of outsourcing strategies. The overall approach employed by BC Hydro is best described by Mr. Elton when he said:

> … And in addition, there are a number of areas where we looked at possible outsourcing: materials management, fleet services, property services, where we, you know, just as we did with all those I've mentioned, we looked at business cases and said, "No, not right now. This is not the right thing to do, to outsource these activities." So I'd say that compared with any other utility that I'm aware of, that this organization has (a) outsourced in two years a substantially larger proportion of its activities than any other I'm aware of, and (b) that we've examined the possibility of outsourcing a greater part of our organization. So there, we've looked for efficiencies directly through seeing what the market could provide and we've made substantial progress.
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> We've not done that ideologically. We've done that in order to either improve service or reduce costs. And that's what we've done.[67]

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[65] T11: 1628/5-8.

[66] At T16: 2835/13-23, Ms. Peverett confirmed that BCTC's compensation policies are not much different from BC Hydro's.

[67] T6: 685/6-23.

In BC Hydro's respectful submission, this overall approach to outsourcing is consistent with the Energy Plan's direction that BC Hydro "will outsource the delivery of services where cost can be reduced for electricity consumers while maintaining quality of service".[68]

The most significant example of outsourcing has already occurred through the arrangement with ABS. The evidence on the benefits to BC Hydro of the ABS transaction are extensively laid out in the evidence.[69] Again, not one intervenor, despite the high profile of this transaction, made a serious effort to demonstrate that the cost of obtaining its services from ABS would be greater than if BC Hydro had continued to self-supply those services.

Mr. Maniago was cross-examined at some length with respect to the allocation of work between Field Services' internal regular, internal contingent, and independent third-party line contractors.[70] While the JIESC spent some time in attempting to demonstrate that the current arrangement with the line contractors was inconsistent with a 10-year old Commission direction to BC Hydro with respect to work allocation,[71] neither the JIESC nor any other intervenor demonstrated that the current arrangement is imprudent, is likely to result in higher-than-necessary costs, or could be replaced with a more cost-effective scheme.

Similarly, Engineering Services provided evidence on undertakings that it is pursuing a strategy of outsourcing where third party service providers can deliver more cost-effective services than

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[68] Energy Plan, Ex. C4-6, p.27.

[69] Regarding the net financial benefits to BC Hydro and its ratepayers, see, for example, Ex. B1-7, BC Hydro responses to BCUC IR #1.96.0 and BCUC IR #1.104.0. Regarding the guaranteed service levels see, for example, T6: 746/12-748/2.

[70] See for example, T10: 1513/10-1514/11 and T11: 1629/22-1630/21.

[71] See T10: 1514/12-1522/12. At T10: 1517/17-1519/2, Mr. Maniago made it clear that the allocation of work between the internal contingent work force and independent contractors has changed dramatically in recent years, in

Engineering Services.[72] Ms. Farrell, in this case specifically on behalf of the Generation line of business, expressed her expectation to continue to work closely with Engineering Services in the next few years to identify those areas where BC Hydro's internal expertise provides valuable benefits that could not be obtained by outsourcing, and conversely identify those areas where third party independent engineering companies could provide services to BC Hydro Generation on a more cost-effective basis than Engineering Services can.[73]

Finally, there is significant evidence on the record, both in the written phase of the hearing and in the oral phase, with respect to BC Hydro's capital and OMA planning processes. The first and perhaps most significant point to make with respect to these processes are that on the evidence before the Commission, those processes are robust and tied closely to BC Hydro's corporate and line of business objectives. While BC Hydro's shareholder has expressed a desire for cost reductions in operations and administration, those cost reductions are targets only, and not to be achieved at the expense of safety or reliability goals.[74] In particular, BC Hydro has no incentive one way or another to budget "high" (or for that matter to budget "low"). The following exchange between Mr. Wallace and Mr. Elton is illustrative:

> [MR. WALLACE: Q:] When people are either asking you for money as the senior executives, or when you're asking the Commission to approve a rate, there is some incentive to be conservative, I wouldn't put it any worse than that, but be conservative in your estimates.
>
> MR. ELTON: A: Yes, I'm not sure I'd call it an incentive. I think there's a requirement for people to be appropriately conservative; in other words to make sure that they describe what they want to spend

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favour of the independent contractors. The underlying premise of the 1994 direction having been eliminated, BC Hydro submits that the issue of compliance with respect to it has become moot.

[72] See Ex. B1-113 and Ex. B1-132.

[73] T20: 3568/16-3571/16.

[74] T17: 2880/20-2882/5.

> money on, and what they will get for that money, and what the risks are that they won't achieve what they expect to get, or that they will spend too much money. I mean what we -- obviously I would hope like any organization, we try and budget at a 50 percent probability level, and I think -- I'm not sure there's an incentive for people to overbudget.[75]

With respect to capital planning, BC Hydro has no incentive to over-invest (and, by extension, to over-plan) because its revenue requirement does not include a return on rate base, as is the case for investor-owned utilities.[76]

A specific example of a budget and prioritization tool used within BC Hydro is the Project Evaluation Tool (PET) employed by the Distribution line of business. The PET is one tool used by BC Hydro engineers to track and prioritize the 100,000 or so work orders per year that the Distribution line of business must manage. As described by Mr. Sherlock:

> ...again because distribution has a system we're managing with 16,000,000 components and about 100,000 jobs or work orders every year, and because we pursue an evergreen planning process; so we don't want to leave the impression that we do the plan once a year and then we just execute that plan the year. With the system as you can imagine with 16,000,000 components and Mr. Gillies can certainly give you more information, it's almost like a living organism, and every day things happen to that system and we have to identify what's happened, whether it's a storm, whether a customer has called where the customer needs a new connection, whether a manufacturer's phoned up and said there's equipment problem, whether we've identified environmental problem. Those are all logged, and those are all logged in Exhibit DG, which is our project evaluation tool. And as you suggested, if you printed that out it's several inches thick. And every single project, in terms of a system improvement, is identified and flagged and put into that system, and there's a ranking and prioritization process that's part of that exercise, and Mr. Gillies can talk about that in more detail if you'd like.[77]

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[75] T5: 509/13-510/1.

[76] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.1.

[77] T14: 2396/2-25.

The PET, a leading practice tool, provides a consistent, reviewable and transparent method of evaluating projects and priorities.[78] In that way, it leverages the skills and technical expertise of BC Hydro's engineering staff. In BC Hydro's submission, it is typical of the rigorous planning and prioritization processes used by BC Hydro.

In BCTC's case, the transmission budgets included in Chapter 6 of the Application are the product of a rigorous budgeting process. Each of the OMA and capital budgets are vetted through various levels of management, and the Chief Financial Officer, before presentation to the Board.[79] Discipline is applied to spending at each stage.

For example, BCTC develops the transmission maintenance program to provide a reliable transmission system from a large set of standards for transmission services, inspections, data from failures, data from reports, recommendations by manufacturers, and regulatory constraints related to safety and the environment. The programs that are identified are prioritized by the asset management program managers and Mr. Mansour and assessed by the CFO for affordability and rate impact.[80]

Where possible, BCTC was able to reduce initial proposed budgets. For example, BCTC cut its original sustaining capital program by $15 million in F2005 and $27 million in F2006. Similarly, the initial organizational structure for BCTC was originally anticipated to require 100 personnel and was reduced through the planning process to 80.[81]

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[78] Ex. B1-94 and Ex. B1-174.

[79] T16: 2782/8-2783/7.

[80] T16: 2780/23-2781/12; T16: 3165/5-3165/17.

[81] T16: 2774/17-2775/23; T16: 2930/21-2931/9.

(e) Specific Revenue Requirement Issues

i) Transmission Revenue Requirement

One of the specific forms of relief sought by BC Hydro in this proceeding is with respect to the different components of the F2006 Transmission Revenue Requirement (TRR). BC Hydro is responsible for, and seeks Commission approval of the BC Hydro Owner's Revenue Requirement component of the F2006 TRR in the amount of $390 million.[82] BCTC is responsible for the BC Hydro Asset Management/Maintenance Revenue Requirement and the BCTC Revenue Requirement components of the F2006 TRR. BCTC has indicated that it will be filing an application later this fall to set these components of the TRR for F2006.[83]

While there was cross-examination on the interplay between these components of the TRR, and in particular their relationship to the BCTC Transition Deferral Account, there was virtually no cross-examination, or issue taken, with the cost and revenue forecasts made to build-up the TRR. One exception was BCTC's lease costs. In that regard, the evidence was that BCTC's choice of premises and the resulting lease costs are appropriate for the utility. BCTC evaluated its choice of location in accordance with ten criteria including cost, proximity to stakeholder groups, convenience and safety for employees. The location selected was the fifth least expensive building, and the second most favourable after consideration of tenant inducements. It was chosen after others were eliminated for reasons of cost, unsuitability, or employee safety concerns. The process included on-site assessments of four of the ten locations that best met BCTC's criteria.[84]

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[82] See the Application, Chapter 6A, p.6A-11, Table 6A-10.

[83] T17: 2960/7-2963/25.

[84] T17: 3033/13-3034/26.

Moreover, BCTC is located in the downtown core for a number of reasons. Unlike other utilities, it does not need to house thousands of employees. It needs to be accessible to the important stakeholder groups. It needs to be located where it is safe and convenient to its employees, and on the SkyTrain. Given those criteria, downtown was a logical location, particularly as it was cheaper than Metrotown.[85]

Finally, the total square footage occupied by BCTC is modest. Benchmarks for occupancy indicated an appropriate range of 200 to 273 square feet per person. BCTC occupies 41,717 square feet, or 178 square feet per person.[86]

Another issue that arose with respect to BCTC (although not precisely in the context of the TRR) was the $17.8 million incremental cost arising from the re-structuring of BC Hydro that gave rise to the creation of BCTC. In BC Hydro's respectful submission, the evidence was clear and persuasive that both BC Hydro and BCTC did what was possible to minimize those costs, but in the end the incremental cost was an unavoidable consequence of the creation of two legal entities where there was formerly one.[87] Mr. Elton, Ms. Van Ruyven and Ms. Farrell all testified to this issue on behalf of BC Hydro, and Ms. Farrell in particular described which business activities of BC Hydro became more complicated and costly as a result of the creation of BCTC, which were unaffected, and which became less costly (if not less complicated).[88] Ms. Peverett and Mr.

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[85] T16: 2834/7-2835/12.

[86] T17: 3036/26-3037/14.

[87] See, for example, Ms. Peverett's testimony at T16: 2831/3-2833/2.

[88] T5: 579/15 to 588/3; T7: 937/22 to 940/1; and T20: 3599/13 to 3603/1.

Mansour testified on this issue on behalf of BCTC, and in particular in regard to the efforts made to minimize incremental staffing.[89]

The only party to file evidence that quantitatively challenged the issue was the CECBC, through the evidence of Mr. Craig. His evidence was that the incremental cost ought to have been $12.8 million, rather than $17.8 million, but under cross-examination he admitted that his analysis was purely arbitrary.[90] He had no ability to identify any specific area in BC Hydro or BCTC where costs could be reduced, nor could he provide any benchmark comparisons. Mr. Craig also testified that driving to an arbitrary external benchmark would not be appropriate.[91] BC Hydro agrees. In BC Hydro's submission, and as articulated above, a purely qualitative assessment of what savings BC Hydro and BCTC might together have been able to achieve is an insufficient basis to disallow any portion of the applied-for rate increase in the face of BC Hydro's appropriate objectives.

ii) Sustainability Expenditures

BC Hydro plans to spend $8.6 million and $8.7 million in each of F2005 and F2006 on corporate sustainability, HydroGen and strategic research and development.[92] This is less than the $10 million amount that BC Hydro would spend if it matched the average per-customer budget for sustainability expenditures of other major utilities.[93] Mr. Elton testified that projects are funded when they are perceived to have value to ratepayers.[94] Under cross-examination, BC Hydro

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[89] T17: 2921/8-16 and T17: 2932/22-2934/26.

[90] T21: 3966/5-20, and T21: 3971/4-3978/25.

[91] T21: 3966/5-24.

[92] The Application, Chapter 3, p.3-53, Table 3-35.

[93] The Application, Chapter 3, Figure 3-3.

[94] T5: 564/19-565/5.

witnesses testified that research expenditures were driven by their respective business units, that some have been made profitable, and that, when appropriate, projects are contracted out.[95]

In BC Hydro's respectful submission, there is no basis on the record to disallow these expenditures.

iii) Adjustment for Vacancies

The proposition was put to BC Hydro by Mr. Wallace for the JIESC that BC Hydro's OMA forecasts were too high because a predictable number of positions are budgeted for but are not "filled".[96] Ms. Webb on Panel 3 confirmed an information request response in testifying that even though positions may be vacant, the cost of those positions is borne through other means, such as increased overtime and use of contractors.[97] In BC Hydro's submission, this is a full answer to the issue, and there is no basis on the record to disallow any portion of BC Hydro's revenue requirement on account of it. Moreover, there is no quantitative evidence on the record that supports the proposition.

iv) Spending Lag

The proposition was put to BC Hydro that its OMA budgets have traditionally been higher than actual expenditures. This proposition was specifically rebutted by Mr. Elton.[98] Counter evidence from Mr. Craig for the CECBC was anecdotal and 10 years out of date.[99] Regarding capital spending lags, it is BC Hydro's submission that they cannot materially affect the revenue

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[95] T15: 2458/2-7 and T18: 3136/24-3139/9.

[96] T10: 1542/14-1543/17.

[97] T10: 1542/20-1543/11 and Ex. B1-8, BC Hydro response to BCUC IR #2.196.0.

[98] T5: 509/13-510/1.

[99] T21: 394/17-395/3.

requirements for F2005 or F2006, and there is no quantitative evidence of their extent or financial impact sufficient to justify a revenue requirement disallowance.

v) Sales Revenue Forecast/Load Forecast

The only material issue that arose with respect to the load forecast and attendant sales revenue forecast for F2005 and F2006 resulted from the divergence between anticipated and actual results in F2004. As the response to the June Financial Undertaking illustrates, industrial and commercial loads were higher than forecast. Residential load was as forecast.

The June Financial Undertaking presents the F2005 and F2006 forecasts employing the actual F2004 load as a starting point. The impact of the changed forecast reflects the extent to which the increased cost of energy is offset by increased revenue from additional sales. In this case, increased sales to industrial and commercial customers yield less revenue than the increased cost of energy.

BC Hydro does not believe it is appropriate to vary the revenue requirement forecast contained in the Application to reflect F2004 numbers. First, it cannot assess the appropriateness of the assumption that F2004 results will be replicated in future years until it has reviewed the reasons for the deviation from forecast in F2004. This work is in progress, but not yet complete. Second, as the June Financial Undertaking makes clear, if the February 20, 2004 cut-off date is abandoned, many variables will change, and any attempt to update for some but not all variables will inevitably be flawed.

In these circumstances, BC Hydro submits that the load and sales revenue forecast as filed in the Application should be employed in determining the revenue requirement for F2005 and F2006.

vi) Prudency of Power Smart Expenditures

Power Smart expenditures are generally capitalized and, thus, do not have an immediate impact on rates. It is the financing costs associated with expenditures made in prior years that impact rates in F2005 and F2006. Thus, the issue for the revenue requirement portion of this proceeding is the prudency of those expenditures.

Because Power Smart expenditures offset the need to acquire new sources of energy, the prudency test as applied to Power Smart has two components. First, is Power Smart the least cost source of new supply? Second, has BC Hydro procured it as efficiently as possible?

BC Hydro's application presents evidence with respect to the second question relating to the efficiency of procurement and there is no suggestion in the evidence that the programs could have been administered more efficiently. Accordingly, this Argument focuses on whether Power Smart was indeed the least cost resource.

Power Smart screens its programs using three cost-effectiveness tests.[100] In each case, the tests estimate the present value of a stream of costs and benefits, the results of which can be stated in the form of a net present value, a benefit/cost ratio, or a levelized value, i.e., ¢/kWh or $/MWh. The appropriateness of these tests and their application were the primary issues discussed during the hearing.

The primary screen employed by BC Hydro in assessing its programs is the total resource cost (TRC) test. This test measures whether an individual program is efficient in the sense that the overall cost of delivering a given amount of energy services to customers is accomplished

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[100] Ex. B1-2, Appendix 1, pp.5-6.

through a Power Smart program at a lower cost than the next least-cost alternative means of acquiring energy.[101] Thus, the test adds the costs incurred by BC Hydro to deliver the program and the costs incurred by the customer to implement it, and compares the sum of those costs against the alternative of purchasing and delivering power to the customer. The Power Smart portfolio as a whole passes the TRC, with a benefit/cost ratio of 1.3 and a levelized cost of 4.4¢/kWh; virtually all of BC Hydro's Power Smart programs pass it too, a result that holds even when portfolio-level costs are allocated to individual programs.[102]

BC Hydro also has regard to the utility cost (UC) test, which is narrower in scope than the TRC and simply considers the costs incurred by the utility itself – both program delivery costs and incentives paid to customers – in comparison to the avoided cost of purchasing and delivering power. BC Hydro believes this test is relevant to assessing the financial risks undertaken by it: placing a limit on the cost it is prepared to incur is an appropriate and prudent additional screen to impose on the Power Smart programs. Thus, BC Hydro believes that the UC screen provides a useful perspective. The Power Smart portfolio has a UC benefit/cost ratio of 2.7 and a levelized cost of 2.1¢/kWh.[103]

BC Hydro performs a third test known as the ratepayer impact measure (RIM). This test is one of equity, not efficiency, and is, in BC Hydro's respectful submission, relevant in assessing whether, having regard to fairness as between ratepayers, the overall Power Smart program is an appropriate component of the REAP. As discussed in more detail in Part 5 of the Argument

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[101] Ex. B1-2, Appendix I, p. 5.

[102] Ex. B1-2, Appendix I, p. 28; Ex. B1-81. The programs that do not pass TRC are discussed on an individual basis in the context of the REAP Application. They are not large programs in a monetary sense and each had specific rationales that support their prudency on an individual basis. For further discussion, see pp.97-98 of this Argument.

[103] Ex. B1-81.

dealing with the REAP, the RIM provides an estimate of rate impacts, not bill impacts. Yet it is bill impacts that matter to customers, and a positive TRC indicates that those impacts are favourable. In other words, even if the RIM indicates that rates may increase, the TRC indicates that the overall customer bill will go down. Thus, BC Hydro believes that projects with a positive TRC meet the essential prudence test the Commission should apply, regardless of their RIM characteristics.

There is no evidence before the Commission to suggest that the Power Smart program in any of the residential, customer or industrial sectors taken as a whole does not pass both utility cost and total resource cost tests. In consequence, the evidence can only support a finding that the programs are efficient. The implication is that the electricity expenditures of customers today are lower than they would have been had BC Hydro not undertaken these past programs. Thus, in the absence of evidence that these same programs could have been delivered more cheaply, it must be concluded that these past expenditures were prudent and BC Hydro should be permitted to recover their costs in rates.

The appropriateness of BC Hydro's proposed future expenditures are discussed more fully in connection with the REAP Application.

Dr. Shaffer, on behalf of BCOAPO, and Mr. Belland, on behalf of the Independent Power Producers Association of BC (IPPBC), did discuss BC Hydro's specific load displacement program. However, Dr. Shaffer and, for that matter, Mr. Belland provided no evidence that the load displacement programs were not a least-cost method of meeting BC Hydro's supply obligation. Both projects proceeded with under the program passed the Total Resource and Utility Cost tests and, accordingly, in terms of their impact on revenue requirement, they were

prudent, cost-effective commitments. As such, Dr. Shaffer's and Mr. Belland's evidence provides no basis to disallow costs associated with those projects. Indeed, had BC Hydro not entered into the load displacement programs, the cost of new electricity supply would have been higher. That follows from the positive TRC associated with these projects. Accordingly, even if Dr. Shaffer's and Mr. Belland's evidence were accepted in its entirety, it would not provide a basis to reduce the revenue requirement.

When the Canfor and Weyerhaeuser negotiations took place, the Commission had not acquired its present review jurisdiction over BC Hydro's resource expenditure and acquisition program in the way that it now has under section 45(6.1) of the Act. As it happens, both Canfor and Weyerhaeuser have a positive RIM.[104] However, if the Commission takes a different view of the RIM associated with these projects, the impact of the Commission's decision will be on permissible expenditures on future load displacement programs, not on recovery of previously committed expenditures with respect to the Canfor and Weyerhaeuser incentives.[105] Because Canfor and Weyerhaeuser are the only material load displacement programs assumed for F2005 and F2006, the views of Dr. Shaffer and Mr. Belland ought to have no impact at all on the revenue requirement for the test years.

BC Hydro does accept that the views of Dr. Shaffer and Mr. Belland with respect to the RIM test are relevant in the context of the REAP. It is in that section of this argument that the specific criticisms of the calculation of the RIM for each project are considered.

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[104] Ex. B1-11, BC Hydro response to BCOAPO IR #1.89.0(b)

[105] T20: 3676/21-3677/15.

vii) Operating to Minimum Reservoir Levels in F2005

In the undertaking filed with this Argument regarding F2005 minimum reservoir operations,[106] BC Hydro explains why, in its view, it would be risky and inappropriate to operate its hydroelectric system to reservoir levels lower than currently planned. In essence, reservoir levels are in the aggregate very close to their minimum levels, and within the range of uncertainty such that unplanned-for reliance on wholesale markets could be very costly, and potentially jeopardizes system reliability. In BC Hydro's submission, its hydroelectric operating practices are among the most sophisticated in the world. With respect, there is simply no basis on the record to second-guess those practices, or to calculate an alternate cost of energy on the basis of a hypothetical and imprudent operating plan.

viii) Past Capital Expenditures on Burrard

An issue pursued by Commission staff was the effect of past capital expenditures, in particular the Burrard Upgrade Project, on F2005 and F2006 revenue requirements. Evidence provided by BC Hydro on this issue supports the prudency of those expenditures at the time they were made.[107] In BC Hydro's submission, it would be inappropriate to second-guess those decisions with the benefit of hindsight, particularly in those circumstances where the Commission was involved throughout.[108] In any event, there is no evidence on the record to indicate the effect on a dollar basis in F2005 and F2006 of those capital expenditures.

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[106] Ex. B1-198.

[107] See generally T20: 3453/17-3477/15. The burden of BC Hydro's evidence regarding the Burrard Upgrade Project is that at each stage of the project further investment made economic sense given conditions at the time; that the bulk of the specific costs were incurred to meet regulatory requirements; and that many parties, including the Commission, were involved in public processes leading to those decisions.

[108] T20: 3454/6-12; T20: 3456/7-20.

ix) Debt Portfolio

Mr. Craig suggested that BC Hydro could save money by having a greater portion of its debt portfolio on a short-term basis.[109] In this, he was entirely confused on the facts[110] and, in any event, his wholly arbitrary judgment in this area should be rejected in favour of the considered opinions of BC Hydro's Treasurer, Ms. Lambert, particularly in light of her reliance on significant studies by external experts.

Mr. Craig made the simple observation that short-term interest rates have been lower than long-term interest rates and used that as a basis for concluding that BC Hydro should have more short-term debt. In essence, he alleged that BC Hydro was overly prudent and should take more risk. He had not done an analysis of the risk profile of BC Hydro nor taken into account the specific characteristics of a public utility the size of BC Hydro.[111] He provided no basis on which to determine the appropriate mix of long- and short-term debt, despite the fact that he acknowledged it would be appropriate to develop a portfolio in that respect. His position seemed to be no more sophisticated than to propose an arbitrary increase in short-term debt in order to accomplish immediate savings for customers.[112]

Mr. Craig's testimony stood in stark contrast to that of Ms. Lambert. She indicated that BC Hydro had employed Salomon, Smith, Barney to do an extensive study, which indicated, given the risk profile of BC Hydro, short-term debt exposure should be in the range of 26% to

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[109] Ex. C35-8, p.16.

[110] T21: 3886; Ex. C35-11; Ex. B1-196.

[111] T21: 3900-02.

[112] Ex. C35-8, p.16, para. 6 - an apparently arbitrary $400 million in 2005, and $300 million in 2006.

46%.[113] She indicated that given current market conditions, it was her judgment in F2004 that short-term debt should be lower,[114] but that for F2005 and F2006, the midrange benchmark of 36% is planned.[115]

Mr. Craig seriously misapprehended this evidence and, in consequence, adjusted his estimate of how much additional short-term debt could be obtained by significantly increasing revolving borrowings in his calculations.[116] This was apparently predicated on his incorrect assumption that revolving borrowings were the only short-term debt of BC Hydro. As set out in Exhibit B1-196, BC Hydro defines short-term debt as any debt which is subject to interest rate reset within one year. This quite sensible definition is used to derive the short-term debt percentage and it is that debt which has the 36% benchmark. Revolving borrowings are but a small part of this exposure.

Thus, there are two ways to answer Mr. Craig. First, the actual short-term debt that BC Hydro anticipated in the revenue requirement is considerably higher than he would choose for F2005. Second, Mr. Craig's willingness to vary the exposure he recommends to short-term debt simply points out the arbitrary and unprincipled nature of his judgment. His recommendations simply cannot be accepted in the face of the testimony of Ms. Lambert and the assessment prepared by Salomon, Smith, Barney.

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[113] Ex. B1-41; T10: 1414/18-1415/20.

[114] T9: 1257/24-26; T10: 1414/18-1415/20; T10: 1417/4-1418/18.

[115] Ex. B1-196.

[116] Ex. C35-11.

x) Cost of Energy

Mr. Craig took a very similar approach to the cost of energy as he did to the cost of money. That is, because he apprehended that short-term energy costs were lower than long-run costs, it was sensible for BC Hydro to be more exposed to short-term prices. The flaw in this logic is the same flaw discussed above with respect to the cost of money. Applied to the cost of energy, it is perhaps even more pronounced.

As Mr. Craig conceded, recent history demonstrates that while there is some scope for short-term energy prices to fluctuate down, there is also scope for them to fluctuate up a great deal more.[117] Thus, it would seem inarguable that a utility in the current environment would want to very carefully consider the extent of its exposure to the short-term market. Ms. Hemmingsen's testimony indicated that BC Hydro had indeed conducted that consideration and concluded that it should be relatively indifferent with respect to the extent of its short-term exposure to market within a limited range, and thereafter would be significantly worse off with greater exposure.[118] There was nothing in Mr. Craig's testimony to give any basis for preferring his assessment in this regard to the analyses performed by Ms. Hemmingsen's group.

xi) Trade Income Forecast

The only significant issues concerning BC Hydro's forecasts of Trade Income for the test years that arose during the hearing were the treatment of outstanding amounts from California and Alcan litigations, and the veracity of the Trade Income forecasts.

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[117] T21: 3949/18-3950/14. See in addition the June Financial Undertaking.

[118] T11: 1792/10-1794/12.

The issue regarding California litigation is the resolution of Powerex's claim against the California Power Exchange Corporation and California Independent System Operator Corp. for power sales in 2000 and 2001, with a potential net recovery of between zero and US$40 million. The Alcan litigation issue arises from an arbitrator's award requiring Alcan to pay US$100 million to Powerex. Mr. O'Riley testified about the considerable uncertainty with respect to the timing and the amount of any monies, if any, that will be received on account of this litigation, consistent with the evidence provided in responses to Information Requests on the topic.[119]

BC Hydro submits that there is no basis for adding amounts in respect of these highly uncertain events to the forecast of Trade Income for either F2005 or F2006. Any recovery on account of these two events will be a contingent gain and recorded as Trade Income when recovered in accordance with GAAP.[120] In the year of such recovery, the difference between forecast Trade Income and actual Trade Income will go into the Trade Income Deferral Account for the benefit of customers, subject to the cap and floor of $200 million and zero.[121]

Regarding the veracity of the Trade Income forecasts, BC Hydro agrees that forecasting Trade Income is inherently challenging because it results from a range of activities and market conditions. BC Hydro acknowledged that the potential range in income is +/- $50 million around the forecast income.[122] However, with the Trade Income Deferral Account and Transfer Pricing Agreement in place, neither BC Hydro nor Powerex have any incentive to bias forecasts

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[119] See, for example, Ex. B1-7, BC Hydro response to BCUC IR #1.23.13; T8: 1083/8-1086/22; and T8: 1087/22-1091/15.

[120] T8: 1087/6-20.

[121] T8: 1162/21-26.

[122] Ex. B1-7, BC Hydro response to BCUC IR #s 1.2.3 and 2.158.2.

of Trade Income, one way or the other, or to operate the system to generate variances from those forecasts.[123]

Mr. O'Riley described, at a high level, the formal process used to develop the Trade Income forecast.[124] Variances from past years' forecasts were shown and explained in BC Hydro's responses to BCUC IR #s 1.1.2, 1.2.1, and 1.2.3.[125] BC Hydro submits that neither the inherent challenges of forecasting Trade Income, nor the fact that past forecasts were often significantly different than actuals, support an inference that Powerex's forecasts of Trade Income are conservative or otherwise such that actual results are more likely than not to exceed forecast results.[126] The forecasts of Trade Income for F2005 and F2006 shown in the Revised Evidentiary Update[127] use the best information available and BC Hydro submits that it would be purely arbitrary to use anything other than those figures for the purpose of determining BC Hydro's revenue requirements for the test years.

C. Proposed Order

BC Hydro requests that the Commission make the following orders:

(i) The interim rate increase of 7.23% authorized by Commission Order No. G-8-04 is confirmed as final, effective on the date of this order.

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[123] Ex. B1-7, BC Hydro response to BCUC IR #1.23.9.

[124] T8: 1212/7-24.

[125] Ex. B1-7.

[126] T8: 1212/25-1214/11.

[127] $89 million and $91 million in F2005 and F2006, respectively, at the Application, Chapter 2A, p.2A-12, Schedule A-1-A (Revised), line 42.

(ii) BC Hydro's application to increase the rates described in Appendix B of its Application by a further 1.67% is approved on a final basis, effective 30 days from the date of this order.

(iii) Subject to (iv) below, the rates described in Appendix B of BC Hydro's Application are confirmed for F2006 to reflect the decision accompanying this order with respect to BC Hydro's F2005 rates.

(iv) BC Hydro's rates described in Appendix B of its Application shall be increased or decreased to reflect Terasen's effective tax rate and allowed return on equity for F2006, upon application by BC Hydro, effective April 1, 2005, on a final basis.

(v) The F2006 BC Hydro's Owners' Revenue Requirement in the amount of $390 million is approved.

III. WTS RATE APPLICATION

A. Summary of Application to Amend WTS Rates

BC Hydro has applied to the Commission for approval of a new TRR for F2005 and F2006, and for new rates for its WTS tariff. Using the same methodology that was approved by the Commission in its 1998 WTS Decision, and adjusting the maximum reserved capacity to reflect the existing supply, the maximum PTP rate will change from $4.681 per kW-month of reserved capacity to $4.555 per kW-month in F2005.[128]

BC Hydro is also proposing that all generation-based ancillary service rates (Rate Schedules (RS) 3004 through 3010) remain unchanged, except where they are directly tied to BC Hydro's prevailing RS 1821. Where RS 1821 is referenced, BC Hydro proposes that the ancillary service price should increase at the same rate as the Commission approves for RS 1821. For RS 3003, BC Hydro is proposing to amend the tariff to reflect the estimated cost to provide this service, again using the same methodology as was used in the 1997 WTS filing but reflecting current cost estimates.

B. Role of the Commission

BC Hydro proposes that the changes to the TRR be applied between Network Integration Transmission Service ("NITS") and Point-to-Point Transmission Service ("PTP") tariffs using the same methodology that was approved by the Commission in its 1998 WTS Decision and adjusting the maximum research capacity to reflect the existing supply. That methodology is currently approved by the Commission, and BCTC expects to revisit it in its 2004 tariff design application. Thus, BC Hydro has not proposed that the methodology be changed at this time.

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[128] The Application, Chapter 6A, p.6A-14, Table 6A-13.

Intervenors did not take issue with this during the proceeding, and BC Hydro submits that the methodology is appropriate.

C. Issue With Respect to WTS Changes

Intervenors did not take issue with BC Hydro's proposed amendment to WTS rates.

D. Proposed Order

BC Hydro requests that the Commission make the following order:

(i) the wholesale transmission rates described in rate schedules 3000 and 3001 and presented in Chapter 6A, Table 6A-13, approved on an interim basis by Commission Order No. G-8-04, are approved on a final basis for F2005.

IV. DEFERRAL ACCOUNT APPLICATION

A. Summary of Application for Deferral Accounts

BC Hydro has applied for Commission approval, pursuant to section 7 of HSD#2, of four new deferral accounts being the Heritage Payment Obligation Deferral Account (HDA), the Non-Heritage Deferral Account (NHDA), the Trade Income Deferral Account (TIDA), and the BCTC Transition Deferral Account (BCTC TDA). BC Hydro's thinking with respect to deferral accounts has evolved starting with the Heritage Contract hearing, followed by HSD#2, and through its various filings in this proceeding. The deferral accounts were described in Chapter 2B of the Application, and were further developed in BC Hydro's responses to information requests,[129] and during the oral hearing.[130]

The four deferral accounts BC Hydro is applying for are conclusively described below.

1. Heritage Payment Obligation Deferral Account

BC Hydro proposes that the following costs and revenues be included in the Heritage Payment Obligation (HPO) for all purposes, pursuant to Schedule A to Appendix A of HSD#2 (parenthetical references refer to items in Schedule A):

1. cost of energy – all variances except those arising from changes in customer load (part of (a)(i));[131]

2. cost of energy – variable costs related to thermal generation (part of (a)(ii));[132]

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[129] See Ex. B1-8 and B1-25, BC Hydro responses to BCUC IRs #2.122.0, 3.220.1, 3.220.2, 3.221.1, 3.221.7, and 3.221.11

[130] See, for example, Ex. B1-33 (the last page of BC Hydro's Opening statement), Ex. B1-108 and the extensive testimony of Ms. Farrell and Mr. Morris on Panels 1, 2, and 7.

[131] See Ex. B1-25, BC Hydro responses to BCUC IRs #3.220.1, 3.221.5, 3.221.7(a), and 3.221.11.

[132] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(a).

3. significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events (part of (a)(ii));[133]

4. significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events (part of (a)(iii));[134]

5. amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02 (part of (a)(iv));[135]

6. all net revenues from surplus hydro electricity sales (all revenues in (b)(iii));[136] and

7. Skagit Valley Treaty revenues (all revenues in (b)(i)) and ancillary services revenues (all revenues in (b)(ii)).[137]

Thus, the forecast HPO is $462.8 million for F2005 and $408.0 million for F2006.[138] BC Hydro is applying for approval to record variances between forecast HPO and actual HPO pursuant to section 7(a)(i) of HSD#2, and for approval to carry those variances forward to subsequent rate periods.

The HPO described above is different from that which was proposed in the original Application[139] because of the subsequent development of BC Hydro's deferral account proposal,

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[133] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(b) and (e).

[134] See Ex. B1-7, BC Hydro response to BCUC IR #1.2.13; and Ex. B1-61.

[135] Ex. A-39.

[136] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(d).

[137] The addition of Skagit Valley Treaty and ancillary services revenues is explained on pp.73-74 of this Argument.

[138] The Application, Chapter 2A, p.2A-37, Schedule D1-3-A (Revised), sum of lines 10, 18 and 19.

[139] See the Application, Chapter 5, p.5-2, Table 5-1 for the original HPO.

which was first described in detail in BC Hydro's response to BCUC IR #2.122.0 and is described conclusively above. BC Hydro did not amend the application in this respect because the change to the HPO does not have any consequences beyond the HDA.

2. Non-Heritage Deferral Account

The components of the HDA, as proposed by BC Hydro, result from BC Hydro's conviction that it should assume financial responsibility for all controllable risks but create deferral accounts for non-controllable risks.[140] This logic applies equally to non-heritage payment obligations. Accordingly BC Hydro is applying for a similar deferral account (the NHDA) for the following additional non-Heritage Payment Obligation components:

1. cost of energy – all variances in non-HPO energy costs except those arising from changes in customer load;[141]
2. significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events;[142]
3. significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events;[143]
4. distribution emergency restoration costs – all variances in emergency restoration expenditures;[144] and

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[140] This principle is discussed in Ex. B1-25, BC Hydro response to BCUC IR #3.221.1, and p.70 of this Argument.

[141] See Ex. B1-25, BC Hydro responses to BCUC IRs #3.220.1, 3.221.7(a), and 3.221.7(f).

[142] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(e).

[143] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(e).

[144] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(g).

5. all Founding Partner Benefits and CIS Credits under the ABS Contract.[145]

The non-HPO cost of energy is forecast at $409 million for F2005 and $423 million for F2006.[146] The distribution emergency restoration cost is forecast at $29.3 million for F2005 and $29.5 million for F2006.[147] The remaining components in the NHDA are forecast at zero. BC Hydro is applying for approval to record variances between these forecasts and actuals pursuant to section 7(b) of HSD#2, and for approval to carry those variances forward to subsequent rate periods.

3. Trade Income Deferral Account

BC Hydro proposes that the TIDA be used to record any variances between BC Hydro's forecast of Trade Income and actual Trade Income, as that expression is defined in HSD#2. BC Hydro proposes that no cap or limit be set on the TIDA, however, any losses on the year or any extraordinary windfalls that would cause Powerex audited net income to exceed $200 million dollars would not be carried forward to future periods, as required by HSD#2.

BC Hydro has forecast Trade Income at $89 million and $91 million for F2005 and F2006, respectively.[148] BC Hydro is applying for approval to record variances between forecast Trade Income and actual Trade Income pursuant to section 7(a)(ii) of HSD#2, and for approval to carry those variances forward to subsequent rate periods.

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[145] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.7(h).

[146] The Application, Chapter 2A, p.2A-20, Schedule A-9-A (Revised), lines 10, 15, 17 and 18.

[147] These forecast amounts are included in the Application, Chapter 7, p.7-21, Table 7-5, in the "Direct" and "Support" lines.

[148] The Application, Chapter 2A, p.2A-13, Schedule A-1-A (Revised), line 39.

4. BCTC Transition Deferral Account

BC Hydro proposes that the BCTC TDA be used to record any variances between the F2006 forecast of the BCTC Revenue Requirement and the BC Hydro Asset Management / Maintenance Revenue Requirement components of the Transmission Revenue Requirement,[149] and BC Hydro's adjusted forecast of those revenue requirements for F2006 based on the outcome of BCTC's F2006 revenue requirement proceeding.

BC Hydro has forecast the F2006 BC Hydro Asset Management / Maintenance Revenue Requirement to be $116.7 million and the F2006 BCTC Revenue Requirement to be $74.0 million.[150] BC Hydro is applying for approval to record variances between the F2006 forecasts of the BC Hydro Asset Management / Maintenance Revenue Requirement and the BCTC Revenue Requirement and adjustments to those revenue requirements as a result of the Commission's decision on BCTC's F2006 revenue requirement application pursuant to section 7(b) of HSD#2, and for approval to carry those adjustments forward to subsequent rate periods.

5. Carrying Costs

BC Hydro is also applying for Commission approval for any balances in the deferral accounts to attract an interest charge or credit that would accumulate in the deferral account. BC Hydro submits that it is appropriate for the balances in these accounts to attract a carrying cost.[151] BC Hydro proposes that annually the average balance in each account attract an interest charge or credit equivalent to BC Hydro's weighted cost of debt during the same period.[152]

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[149] These terms are explained in the Application, Chapter 6, pp.6-81 to 6-83).

[150] The Application, Chapter 6A, p.6A-11, Table 6A-10.

[151] See Ex. B1-8, BC Hydro response to BCUC IR #2.202.5.

[152] See Ex. B1-8, BC Hydro response to BCUC IR #2.202.5 and the Application, Chapter 2B, p.2B-3, lines 24-25.

B. Role of the Commission

Pursuant to section 7 of HSD#2, the Commission:

> (a) **must** allow BC Hydro to establish one or more accounts to reflect and record variances between
>
> (i) the heritage payment obligation and the authority's forecast of the heritage payment obligation, and
>
> (ii) the trade income and the authority's forecast of trade income,
>
> (b) **may** allow BC Hydro to establish one or more other deferral accounts for other purposes, and
>
> (c) **must** set or regulate BC Hydro's rates in such a way as to allow the deferral accounts to be cleared from time to time and within a reasonable period of time. **[emphasis added]**

Thus, the Commission must allow BC Hydro to establish accounts to reflect and record variances between the Heritage Payment Obligation and BC Hydro's forecasts of the Heritage Payment Obligation, and between Trade Income and BC Hydro's forecast of Trade Income. The Commission has discretion to allow BC Hydro to establish other deferral accounts for other purposes.

In reviewing the proposed HDA, BC Hydro submits that the role of the Commission is to determine if BC Hydro's proposal is in accordance with the requirements of HSD#2 and, to the extent the Commission has discretion to approve the cost components of the HPO, that BC Hydro's proposal allocates risk appropriately amongst BC Hydro and current and future customers.

Pursuant to section 7(a)(ii) of HSD#2 the Commission must also allow BC Hydro to establish an account to reflect and record variances between Trade Income and BC Hydro's forecast of Trade Income, as that terms is defined in HSD#2:

> **"trade income"** means the audited net income of Powerex Corp., according to generally accepted accounting principles, adjusted by,
>
> (a) if the audited net income is less than zero, adding the amount necessary to make it zero, and
>
> (b) where the audited net income is greater than $200 million, subtracting any amount in excess of $200 million.

BC Hydro submits that the role of the Commission in reviewing the proposed TIDA is to determine if BC Hydro's proposal is in accordance with the requirements of section 7(a)(ii) and the definition of Trade Income in HSD#2.

Pursuant to section 7(b) of HSD#2 the Commission may allow BC Hydro to establish other deferral accounts for other purposes and BC Hydro proposes to establish the NHDA and BCTC TDA under that section. In reviewing these discretionary accounts, BC Hydro submits that the role of the Commission is to determine if BC Hydro's proposals in respect of these accounts are consistent with and appropriate in light of the balance struck between the interests of BC Hydro and current and future customers, and the principles BC Hydro proposes below.

C. Issues With Respect to Deferral Accounts

1. Compulsory Deferral Accounts

(a) HDA

BC Hydro submits that its HDA proposal is consistent with the requirements of section 7(a)(i) of HSD#2, which provides for an account to reflect and record variances between the HPO and BC Hydro's forecast of the HPO.

In reviewing the proposed HDA, BC Hydro submits the Commission must determine the appropriate cost and revenue items to include in the HPO. In making these determinations, the

Commission must have regard to the definition of Heritage Payment Obligation in HSD#2, which in turn refers to the definition in the Heritage Contract as follows:

> **"heritage payment obligation"** means
>
> (a) subject to paragraph (b), the annual payment determined in accordance with the procedure set out in Schedule A to this Heritage Contract, or
>
> (b) the annual payment determined by the Commission under section 8 of the Heritage Contract to be the heritage payment obligation.

Thus, the HPO is to be determined in accordance with either paragraph (a) or (b) of the definition. In BC Hydro's respectful submission, paragraph (b) is not relevant to this proceeding because it deals with changes in circumstances that have permanently affected the capability of the heritage resources or BC Hydro's cost of generating the heritage energy. In BC Hydro's submission, there have been no such changes in circumstances, and, thus, paragraph (a) of the definition directs the Commission to the procedure it shall use to determine the HPO, as follows:

> The heritage payment obligation for any Year is the amount determined by
>
> (a) adding those of the following costs incurred by BCH Generation in the Year **that the Commission orders may be included** in the heritage payment obligation:
>
> (i) cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;
>
> (ii) operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;
>
> (iii) all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;
>
> (iv) all costs or payments related to generation-related transmission access required by the heritage resources;
>
> (v) the applicable return on equity on investments in heritage resources based on Heritage Special Direction No. HC2 to the Commission under the authority of the Act, and

(b) by subtracting from the sum obtained under paragraph (a), any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,

(i) revenues related to Skagit Valley Treaty obligations,

(ii) revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

(iii) revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement. **[emphasis added]**

The emphasised phrase, above, provides the Commission with discretion to determine the elements of the costs listed in paragraph (a) of Schedule A that are to be included in (or excluded from) the HPO. That is, all of the costs listed there do not need to be included in the HPO if the Commission so determines.

BC Hydro submits that the descriptions of the cost categories in Schedule A are imprecise and that the imprecise language was used to provide the Commission with a broad list of cost categories from which it must determine the appropriate costs to include in the HPO. BC Hydro further submits that a principled approach should be used by the Commission to make this determination.

A key overriding principle is that BC Hydro has an obligation to provide low cost power to customers and to provide the return to the shareholder prescribed by Special Direction. BC Hydro is not seeking to try to beat that return through the use of deferral accounts, instead, its overriding principles for deferral accounts are to use them as a mechanism to provide smooth

and stable rates for customers,[153] and to avoid the need to build amounts into budget for unplanned and unexpected events.[154]

BC Hydro wishes to limit the cost components included in the HDA to those that are non-controllable by BC Hydro because of BC Hydro's conviction that it should assume financial responsibility for controllable risks and create deferral accounts for non-controllable risks.[155]

In discussing the controllable vs. non-controllable principle, BC Hydro elaborated that it also intended to capture the following characteristics:

- BC Hydro's ability to directly or indirectly influence the cost category;
- the volatility of the cost category;
- the predictability of the cost category;
- the materiality of the cost category to the revenue requirement; and
- the frequency of major exceptions within the cost category.[156]

As discussed above, section 7(a)(i) of HSD#2 requires that the HDA record variances between the HPO and BC Hydro's *forecast* of the HPO, with the HPO consisting of those of the costs listed in Schedule A to the Heritage Contract that the Commission orders included in the HPO,

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[153] T7: 977/6-987/2; T8: 1209/7-14.

[154] T7: 826/9-18; T8: 1060/24-1061/15.

[155] See Ex. B1-8, BC Hydro response to BCUC IR #2.122.0.

[156] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.1; T7: 972/4-20.

minus the listed revenues. Mr. Morris provided the following testimony about the relationship of the forecast to the deferral account in response to a question by Mr. Wallace:

> MR. WALLACE: Q: And wouldn't that longer-term view lead you to move the deferral account toward average rather than to what you happen to see immediately, as a centering point?
>
> MR. MORRIS: A: Theoretically I think the changes in the deferral account themselves would move towards average, but we're not forecasting items to go into the deferral account, so there's no direct link between one or the other. A forecast is a forecast based on the best information at the time, and then the actual conditions we know will be different, and it's the difference between the two of those that go into the deferral account.[157]

Mr. Spafford expanded on the basis for the forecast, as follows:

> The original application was based on the starting reservoir elevations as of October 1, 2003, and made the assumption of normal precipitation from that point forward. The evidentiary update was based on the reservoir elevations as we knew them on January 1st of 2004 and used the assumption of normal precipitation, normal water conditions from that point forward.[158]

Thus, as required by HSD#2, BC Hydro has proposed that the HDA record the differences between *forecast* and actual HPO.[159]

As the Chair summarised at T20: 3582, a number of intervenors have suggested that the year should be started with different reservoir levels than actual levels or a different basis for the forecast; that the HDA should be based on "average" or "normal" conditions rather than forecast conditions.[160] BC Hydro submits that basing rates or the HDA on anything other than a forecast

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[157] T8: 1057/8-20.

[158] T18: 3227/17-24.

[159] T8: 1055/4-26.

[160] T8: 1056/1-1057/23 (Mr. Wallace); T19: 3331/14-16 (Mr. Weafer).

based on the best, known, information available at the time would be contrary to the Special Direction.

Basing the HDA on "average" or "normal" conditions would be arbitrary,[161] speculative,[162] would likely create a much larger balance in the deferral account at the end of the year[163] which could lead to bigger rate increases in future years,[164] and it would be inconsistent with the way that BC Hydro and others in the industry manage their operations.[165]

In addition to the difficulties, uncertainties and deferral of foreseeable costs associated with using arbitrary "normal" conditions for the HDA that have been identified by the BC Hydro witnesses, the issues of initial reservoir levels and water conditions for the Heritage Contract has already been addressed by BC Hydro during the Heritage Contract proceeding. In that proceeding it said:

> BC Hydro does not propose to make an explicit adjustment for reservoir levels, but instead proposes to rely on the Heritage Deferral Account to capture the cost impacts of the actual initial reservoir conditions. For example, if the initial reservoir levels at the start of the Heritage Contract were low, there would be a greater likelihood that the Heritage Payment Obligation would be higher than if the initial water conditions were more favourable. This is an appropriate mechanism to account for initial water conditions because the Heritage Contract proposal reflects a continuation of the benefits that the Heritage Beneficiaries currently enjoy from the BC Hydro system.[166]

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[161] T18: 3230/15-24.

[162] T19: 3333/3-9.

[163] T19: 3340/11-17; T20: 3582/19-3583/13.

[164] T19: 3340/17-21.

[165] T18: 3231/4-3232/14.

[166] A Proposal by BC Hydro dated April 30, 2003, regarding a Heritage Contract, Stepped Rates and Access Principles, Volume 1 of 2, at page 36, section 3.5.2.

The result of that proceeding, of course, was the Commission's October 17, 2003 Report and Recommendations which accepted BC Hydro's Heritage Contract proposal and recommended it to government.[167]

Mr. Craig, on behalf of the CECBC appears to be asking the Commission to revisit the Heritage Contract inquiry:

> Well, for operating the system I would say that BC Hydro should do it as they have proposed to do it. For rate setting, I think it's very important that we use normalized stream flows for the entire period of time, because otherwise you get the impact of setting rates based on whatever that amounts to…[168]

This is the same kind of argument (that cost components should be fixed for the entire term of the Heritage Contract) that was rejected by the Commission during the Heritage Contract inquiry. BC Hydro respectfully submits that these issues have been thoroughly debated and that there is no reason to reconsider them now.

BC Hydro did not apply for deferral account treatment of Skagit Valley Treaty revenues and ancillary service revenues because these revenues are not material in the context of BC Hydro's revenue requirement, and hence do not warrant a deferral account.[169] While BC Hydro continues to believe that variances in these revenues do not justify a deferral account on a principled basis, BC Hydro now believes that these revenues must be included in the HDA pursuant to paragraph (b) of Schedule A to Appendix A to HSD#2, which does not provide the Commission with discretion to exclude those items. Variances in these revenues are not expected to be volatile or

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[167] BCUC Report and Recommendations dated October 17, 2003, at page 34.

[168] T21: 3971/13-18.

[169] See Ex. B1-8 and B1-25, BC Hydro responses to BCUC IR #s 2.122.0 and 3.220.4.

material and BC Hydro does not expect that other parties in this proceeding will suffer any prejudice as a result of this minor amendment to BC Hydro's deferral account application.

The following two cost categories that BC Hydro proposes to exclude from deferral account treatment received significant attention during the hearing: cost and revenue changes arising from changes in customer load, and changes arising from changes in finance charges. These are discussed below.

BC Hydro proposes to exclude from deferral treatment variances between customer load and forecast customer load. BC Hydro accepts that it should bear the risk of the accuracy of its load forecast.[170] Furthermore, changes in customer load around forecast are assumed to be symmetrical and are not expected to have sufficient variability to warrant putting it into a deferral account.[171] BC Hydro proposes to calculate the cost of energy assignable to changes in customer load using the methodology set out in BC Hydro's response to BCUC IR #3.221.11, as further elaborated by Mr. Morris in response to questions from the Chair at T10: 1475/8-1485/4. BC Hydro submits this methodology is appropriate because it matches cost to revenues in the event customer loads are greater than or less than forecast.[172]

BC Hydro has proposed to exclude from deferral treatment variances in finance charges from forecast because BC Hydro uses natural internal hedging as well as financial instruments to manage interest rate and foreign exchange risks related to debt service. Although interest and foreign exchange rates are exogenous, and not controllable by BC Hydro, they are more

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[170] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.4.

[171] T8: 1198/3-1199/1; T8: 1201/2-5; and T9: 1392/14-1393/22.

[172] See Ex. B1-25, BC Hydro response to BCUC IR #s 3.221.11 and 3.220.1; T10: 1475/24-1476/7.

predictable than some of the other costs BC Hydro is proposing for deferral treatment,[173] and the corresponding risks can be managed through the use of such instruments and effective management of the debt portfolio. Excluding finance charges from a deferral account acknowledges this ability to mitigate the associated variability by allocating the risk for these charges to the shareholder rather than the ratepayer.[174] Note that currency exchange risk is now covered, to an extent, by a deferral mechanism under Commission Order No. G-47-02.[175]

BC Hydro submits that the Commission must allow BC Hydro to establish a deferral account to record variances between the HPO and BC Hydro's forecast of the HPO. The Commission has discretion, pursuant to section 7(a)(i) and Schedule A to Appendix A of HSD#2, to place limits on the cost elements that are included in the HPO. BC Hydro submits that the controllability characteristics of ability, volatility, predictability, materiality and frequency identified above are appropriate criteria for determining cost elements to include in the HDA and the Commission should approve the HDA (as amended to include Skagit Valley Treaty and ancillary service revenues).

Should the Commission decide that any of the cost elements proposed by BC Hydro to be included in the HDA do not fit within the definition of HPO in HSD#2, any such items could be included in the NHDA, consistent with BC Hydro's conviction that deferral accounts should be created for non-controllable risks. BC Hydro respectfully submits that this would be an appropriate solution to ensure consistency of cost components that have deferral treatment.

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[173] T5: 533/13-17.

[174] See Ex. B1-25, BC Hydro response to BCUC IR #3.220.4.

[175] Order No. G-47-02 is summarised in the Application, Chapter 2, p.2-13, lines 14-19.

(b) TIDA

BC Hydro proposes to record variances between BC Hydro's forecast of Trade Income and actual Trade Income, as defined in HSD#2, and submits that its TIDA proposal is consistent with the requirements of section 7(a)(ii) of HSD#2.

2. Discretionary Deferral Accounts

(a) NHDA

BC Hydro has applied for the NHDA and BCTC TDA under section 7(b) of HSD#2, which provides that the Commission may allow BC Hydro to establish deferral accounts for "other purposes". BC Hydro proposes two principles regarding the other purposes for which deferral accounts are appropriate. The first principle is controllability of costs, which is discussed above, and the second is consistency. Consistency is an important principle because many cost categories in the HDA (e.g. the cost of energy) have a portion in the HDA (e.g. the hydro component of the cost of energy) and a portion that is not in the HDA (e.g. the IPP component of the cost of energy).[176] This inconsistency could lead to a conflict or perversity in calling on system resources because some, but not all, of the energy would be in deferral accounts. It would also make it very difficult for BC Hydro to manage, report to the Commission, measure accountability, and assess performance.[177]

Thus, BC Hydro has applied for the NHDA for non-controllable, non-heritage payment obligation, cost elements. The NHDA is essentially the same as the HDA with the exception of

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[176] Ms. Farrell discussed some of the other cost categories that have portions in, and not in, the HDA at T7: 968/14-970/22.

[177] T7: 970/23-971/17.

two elements: distribution emergency restoration costs, and Founding Partner Benefits and CIS Credits under the ABS Contract.[178]

Distribution emergency restoration costs are planned at a certain amount and any variances around plan, positive or negative, would be put in the deferral account. These costs are not controllable by BC Hydro.[179]

Founding Partner Benefits and CIS Credits under the ABS Contract are summarised in the Application, Chapter 9 at pages 9-64 and 9-65, and further discussed in BC Hydro responses to BCUC IR #s 2.163.1(a) through 2.164.0(b). Because these benefits and credits depend on uncertain external events outside BC Hydro's control and BC Hydro is unable to estimate these benefits for the test years due to uncertainty of the amount and timing of the benefits,[180] BC Hydro proposes that any such benefits that are realised in the test years will be put in the NHDA for the benefit of customers.

(b) BCTC TDA

BC Hydro has also applied for the BCTC TDA under section 7(b) of HSD#2, as described above. The responsibilities, as between BCTC and BC Hydro, for the three revenue requirement elements of the Transmission Revenue Requirement are set out in Exhibit B1-108. The BCTC Revenue Requirement and the BC Hydro Asset Management / Maintenance Revenue Requirement are BCTC's to change, while the BC Hydro Owner's Revenue Requirement is BC Hydro's to change, with any changes subject to Commission approval.

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[178] See Ex. B1-8 and B1-25, BC Hydro responses to BCUC IR #s 2.122.0 and 3.221.7.

[179] T8: 1202/12-20.

[180] See Ex. B1-8, BC Hydro response to BCUC IR #2.165.0.

The BC Hydro Owner's Revenue Requirement is being set for the two test years in this proceeding and it will not change in F2006. The BCTC Revenue Requirement may change as a result of the Commission's decision on BCTC's F2006 revenue requirement application. Any such variances would be beyond BC Hydro's control and thus, BC Hydro proposes that they be recorded in the BCTC TDA and carried forward to subsequent rate periods. As stated during the hearing, BC Hydro's position is that the F2006 forecast of the BC Hydro Asset Management / Maintenance Revenue Requirement ought to change only in consequence of the Commission's decision on the BCTC Revenue Requirement.[181]

3. Incentives to Ensure Control of Costs in Deferral Accounts

As described above in Part 2 of this Argument, BC Hydro is managed with the objective of long-term cost effectiveness in mind, consistent with returns to its shareholder and low rates.

Ms. Farrell testified that deferral accounts will not reduce management's incentive to do the best job it can to achieve the shareholder's two basic objectives of low rates and the return prescribed in the Special Directions.[182]

Mr. Elton and Ms. Farrell also made it clear that the incentives for BC Hydro management will not be affected by deferral accounts because BC Hydro's shareholder does not recognise deferral accounts when it consolidates the income of BC Hydro.[183] The following testimony from Ms. Farrell is illustrative:

> So the use of the deferral account is a way to smooth rates for customers over a period of time. However, in our particular circumstance our

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[181] T5: 399/18-26.

[182] T6: 803/3-804/10.

[183] T5: 504/4-13; T5: 505/10-507/1; T5: 508/19-24; T6: 718/6-19; T6: 801/14-802/12.

> shareholder cannot recognize those deferral accounts when calculating net income. So when the shareholder consolidates the income of B.C. Hydro into the province it has to consolidate it based on what the actual net income was. So we are under pressure day in and day out to deliver on our budgets and deliver on what we've told the shareholder our budgets will be. And that is part of the incentive that we see that in effect says that the incentive we have to deliver our budgets is somewhat separate from the ability to put money into a deferral account such that we can smooth rates for the customers. [184]

Thus, BC Hydro submits that the incentives for management to control costs are not reduced by the deferral accounts BC Hydro has proposed.

4. Clearing of Deferral Accounts

Section 7(c) of HSD#2 provides that the Commission must set or regulate BC Hydro's rates in such a way as to allow the deferral accounts to be cleared from time to time and within a reasonable period of time.

Mr. Morris provided detailed testimony about the process, and standards, that BC Hydro proposes be used by the Commission to review the prudency of amounts in the deferral accounts and the manner in which those amounts be taken into the revenue requirement.[185]

In summary, BC Hydro proposes that the prudency review should happen close enough in time to the events giving rise to the deferral accounts to allow for meaningful review. In particular, reviews of amounts in the deferral accounts should occur at least at every revenue requirement hearing and between revenue requirement hearings if deemed advisable by the Commission.

After that review has occurred, and amounts are deemed appropriate for inclusion into the revenue requirement, they should only be taken into the revenue requirement if the Commission

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[184] T5: 506/11-507/1.

is persuaded, on application under section 7(c) of HSD#2, that the accounts should be fully or partially cleared because the amount that has accumulated is unlikely to be offset by events in future years and should begin to be reflected in rates to avoid the potential for a significant impact on rates in future years.[186]

BC Hydro proposes that no cap or limit be set on any of the deferral accounts, and that the accounts be looked at together rather than separately when determining amounts be taken into the revenue requirement. The decision of the quantum to apply for during a particular test period would be determined by the balances in the accounts and factors such as water inflows, interest rate variations, or other factors affecting BC Hydro's financial outlook and expectation around future revenue and rate requirements. The objectives in determining the appropriate amount to dispose at any one time, and the period of time to take that amount into rates, would be smooth and stable rates for ratepayers.[187]

BC Hydro proposes that the Commission apply the same standard of review to each category of expense or revenue in the deferral accounts as it would have when setting a revenue requirement prospectively. Mr. Morris provided testimony about the appropriate standard of review for each category of expense or revenue in the deferral accounts, as follows:

> Thus, the BCTC transition deferral account should be subject to little or no prudency review because it will be a product of the Commission's decision on BCTC's revenue requirement application and as such, the issue of prudency does not arise.

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[185] T8: 1034/17-1041/25; Ex. B1-9.

[186] T8: 1036/8-1037/21; see Ex. B1-25, BC Hydro response to BCUC IR #3.221.6.

[187] See Ex. B1-25, BC Hydro response to BCUC IR #3.221.6; T6: 810/21-812/5; and T8: 1037/6-21.

> With respect to the trade income deferral account, prudency should only be an issue in the very limited way that the forecast of Powerex's net income is an issue in these proceedings.
>
> On the other hand the amounts in the Heritage deferral account and the non-Heritage deferral account will be subject to prudency review to the same extent these items are subject to reasonableness review in a proceeding such as this one.[188]

BC Hydro submits that the BCTC TDA should be subject to little or no prudency review because any amounts in that account will be a product of amounts that have been approved by the Commission as prudent in its decision on BCTC's revenue requirement application.

With respect to amounts in the TIDA, these are variances between Trade Income (defined in HSD#2 as the audited net income of Powerex according to GAAP) and BC Hydro's forecast of Trade Income. BC Hydro submits that the review of these variances should only be in the very limited way that the forecast of Powerex's net income is an issue in prospective revenue requirement setting. Thus, the scope of review is limited to looking at the audited financial statements of Powerex as prescribed in the definition of Trade Income, and as confirmed by the Chair at T8: 1080.

With respect to amounts in the HDA and NHDA, these amounts should be subject to prudency review to the same extent they would be subject to reasonableness review when setting a revenue requirement prospectively, that is, the test should be whether BC Hydro was prudent at the time the expense or revenue item in the deferral account was incurred.

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[188] T8: 1035/11-25.

BC Hydro will provide the Commission with quarterly reports of the balances in each of the approved deferral accounts including details on changes in the balances for each of the cost components of the HDA and NHDA.

D. Proposed Order

BC Hydro requests that the Commission make the following orders:

(i) The Heritage Deferral Account proposed by BC Hydro and the following Heritage Payment Obligation forecasts for F2005 and F2006 are approved:

	Forecast Heritage Payment Obligation ($ millions)
F2005	$462.8
F2006	$408.0

(ii) The Non-Heritage Deferral Account proposed by BC Hydro and the following cost component forecasts for F2005 and F2006 are approved:

F2005	Forecast ($ millions)
Non-HPO Cost of Energy	$409.0
Distribution Emergency Restoration	$29.3
F2006	
Non-HPO Cost of Energy	$423.0
Distribution Emergency Restoration	$29.5

(iii) The Trade Income Deferral Account proposed by BC Hydro and the following Trade Income forecasts for F2005 and F2006 are approved:

	Forecast Trade Income ($ millions)
F2005	$89
F2006	$91

(iv) The BCTC Transition Deferral Account proposed by BC Hydro is approved. The following forecasts of the F2006 BC Hydro Asset Management / Maintenance Revenue Requirement and the F2006 BCTC Revenue Requirement are approved for the purposes of the BCTC TDA:

F2006	Forecast ($ millions)
BC Hydro Asset Management / Maintenance Revenue Requirement	$116.7
BCTC Revenue Requirement	$74.0

V. REAP APPLICATION

A. Introduction

BC Hydro has filed its REAP[189] pursuant to section 45(6.1) of the Act. In this document, BC Hydro has identified the capital expenditures and demand side management (DSM) expenditures it intends to make over the next two years and the resource acquisition expenditures over the next four years. Because this is BC Hydro's first filing pursuant to section 45(6.1), it raises some significant issues concerning the role of the Commission, as well as some specific issues of substance.

B. Role of the Commission

BC Hydro has proposed the REAP and the approval process associated with it in the context of its long-run integrated electricity plan (IEP) and its short-run investment in specific energy acquisition, capital expansion projects or DSM initiatives. It is BC Hydro's central contention that the recent revisions to the Act provide for a flexible, iterative process that is intended to keep the Commission fully informed of BC Hydro's plans as they develop, thereby permitting the Commission to signal its preferences and allow BC Hydro to adapt its plans accordingly.

As BC Hydro sees it,[190] the process necessarily begins with the IEP. The IEP is a 20-year outlook that identifies options, as opposed to choosing amongst them. To facilitate realistic comparisons of different options, the IEP constructs alternative portfolios of resources and seeks to determine how those portfolios perform in the face of alternative outcomes with respect to key forecast variables. Thus, the IEP is a central management tool that provides essential

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[189] Ex. B1-23.

[190] A full description of the planning approval process envisaged by BC Hydro can be found at T8: 1002/16-1019/7.

background to BC Hydro's Board to determine whether specific decisions that BC Hydro is called upon to make from time to time are in keeping with a coherent long-run vision.

BC Hydro intends to prepare IEPs every other year. It plans to obtain the public input necessary to ensure that its views of the future evolve with full knowledge of the competing perspectives that First Nations and its stakeholders may have.[191]

BC Hydro plans to make the IEP public and, most importantly, file it with the Commission every other year upon completion. This ensures that the Commission will have as full an understanding of developing issues BC Hydro faces as BC Hydro itself does and can accordingly place any decisions it is called upon to make in the context of BC Hydro's long-run circumstances.

Because the IEP makes no commitment to specific capital expenditures, resource acquisitions or DSM expenditures, there is nothing in it requiring approval, nor does the Act require such approval. Of course, the Act does require a public utility to file a plan of its capital expenditures, demand side management expenditures and resource acquisition costs, all for a future period to be prescribed by the Commission. In the Application, BC Hydro has suggested that timeframe should be two years for demand side management and capital expenditures and four years for energy acquisition. The two-year capital plan and the first two years of the Power Smart 10-Year Plan reflect the two-year test period set by BC Hydro in the Application. The resource acquisition plan reflects the slightly longer-term outlook for a four-year period consistent with the Commission's Resource Planning Guidelines and the need to identify the planned energy acquisition strategies over a period sufficient to permit the IPP community to respond.

BC Hydro sees the REAP as the central document that will receive review and approval by the Commission. BC Hydro intends to file a REAP annually. The form it takes will depend on whether or not it is filed concurrently with a revenue requirement application.

In years where BC Hydro is seeking approval of new rates, as it is in this Application, the REAP will necessarily draw heavily on the revenue requirement application. Thus, anything in the REAP that will have an effect within the test years involved in a revenue requirement application will necessarily be fully developed in that application. That is the case with the current process and explains why the REAP application filed March 31, 2004 is summary in form. The detail upon which it relies and which is incorporated into it by reference is fully developed in the relevant chapters of the Revenue Requirements Application.

Thus, with respect to capital expenditures, the REAP simply recasts Chapter 11 of the Application and the explanations contained in the chapters describing each of the lines of business in connection with the rationale for those expenditures. Similarly, the REAP describes DSM expenditures which are more fully described in the discussion of Power Smart in the Application.

On the resource acquisition side, the REAP elaborates some portions of the cost of energy chapter in the Application, but it also goes on to encompass those commitments which are anticipated to be made during the REAP period (i.e., the next four years), whether or not they result in expenditures by BC Hydro in that period. BC Hydro believes this is appropriate to ensure that the Commission is made aware of proposed expenditures and approves the plan of which they are a part before a long-term commitment is made.

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[191] T6: 609/11-22; T7: 986/2-22.

BC Hydro believes that the Act does not contemplate, nor does efficient regulation require, contract-by-contract approval with respect to resource acquisition expenditures.[192] Rather, section 45(6.2) permits the Commission to establish a review process that is appropriate to the needs of a particular utility and its stakeholders. The Commission may also determine which expenditures, if any, it believes should be assessed for appropriateness and which expenditures should be identified as recoverable in rates at that stage of the process.

It is BC Hydro's submission that based on the material filed in this Application, the Commission should make some specific determinations regarding BC Hydro's proposed expenditures as identified in this REAP and, as well, to lay down some general guidelines for future REAPs and revenue requirement applications.

In the context of this particular hearing, BC Hydro believes that the specific expenditures contemplated both of a capital nature and with respect to DSM generally have been fully vetted through the Revenue Requirements Application and those aspects of the REAP should be approved for future recovery in rates. That is, there should be no further enquiry into whether these specific expenditures fully described and contemplated for the test years are prudent. The Commission is well positioned to make a final determination in that respect.

Regarding resource acquisition, BC Hydro requests the Commission to determine:

(i) that expenditures made pursuant to existing energy purchase agreements are in the public interest and ought to be recoverable in rates; and

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[192] Ex. B1-9, Direct Evidence of Mr. Elton, p.4.

(ii) that committing to acquire an additional 400 GWh through an energy call, conducted generally in accordance with the procedures employed in previous energy calls and in a way that ensures a level playing field between all bidders into the process, is a prudent action that should be approved and that any expenditure commitments made pursuant to that energy call should be recovered in future rates, provided that BC Hydro has filed the EPAs with the Commission and the Commission is satisfied that their individual terms comply with the framework established by the energy call.

Thus, it is BC Hydro's proposal that the Commission exercise its authority under sections 45(6.1) and (6.2) to confirm that it is appropriate to acquire an additional 400 GWh of energy and that a competitive call is the appropriate way to do that. Having made that determination, the resulting costs should be recoverable in rates, provided that BC Hydro carries out its intention in a manner that is consistent with that described in this Application.

The proposed 400 GWh call will be conducted using the same general approach employed by BC Hydro in the five calls it has employed since 2001, modified to respond to input received from IPPs and other stakeholders.[193] Although the witnesses for IPPBC had a number of criticisms of BC Hydro's energy acquisition strategy, none of them related to the manner in which calls were being conducted. IPPBC witnesses, Steve Davis and Harvie Campbell, appeared to accept that the processes had been conducted fairly in the past, with BC Hydro working hard to improve the process each time.[194] They did not request the Commission's

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[193] T14: 2235/17-2236/1.

[194] T21 :3878/26-3880/13.

intervention in that process[195] and BC Hydro respectfully submits that such intervention in a competitive process would be inappropriate.

The REAP covers four years for energy acquisition. BC Hydro will be filing a new REAP every year. If changed circumstances or changed strategic direction identified in the IEP lead to required changes in the REAP for years 2, 3 and 4, BC Hydro will make revisions on a rolling basis as required. Thus, determinations by the Commission that expenditures are appropriate is only required for those items identified in the first year of the REAP or within the test period of a coincident rates application.

In the future, BC Hydro expects that the REAP will be a significant stand-alone document in those years when there is not a companion revenue requirement application and in all years it will be derivative of the most recent IEP. Thus, the Commission will have the planning context in which to assess the REAP and will have an annual rolling succession of REAPs in order to quickly identify any departure from a previous year's plan. This will allow the Commission to determine on a year-by-year basis whether or not there is any significant change of direction or major commitment being contemplated by BC Hydro sufficient to justify a full-scale review or inquiry. This flexible approach should allow the process employed to conform to the needs of BC Hydro and its stakeholders on an annual basis.

The approach that has been outlined above should go a long way to eliminating the need for a significant process relating to the issuance of CPCNs and relating to the review of energy supply agreements pursuant to section 71 of the Act. In the case of CPCNs, most of BC Hydro's capital expenditures are already deemed to have a CPCN by section 45(1) of the Act. Pursuant to

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[195] T21: 3876/3-3877/3

section 45(5), CPCNs are only required for BC Hydro where the Commission deems them to be necessary. BC Hydro believes that the iterative process commencing with the IEP and proceeding through the REAP and revenue requirement processes ought to generally eliminate the need for a CPCN to determine need or cost-effectiveness. This should eliminate the need in most circumstances for specific review of extensions of BC Hydro's system. The exception may be major generation projects that have significant potential for cost variation or other unforeseen impacts. Site C is the best example of such a project.

A parallel situation exists with respect to section 71 of the Act. Like the CPCN provisions of section 45, the Commission is not required to approve energy supply contracts of BC Hydro, but it is able to intervene if it believes that a contract is not in the public interest.

EPAs must be filed with the Commission. The Commission is not obliged by the Act to take any steps in response to filing, but if it has reason to believe that an EPA may not be in the public interest, the Commission may make an order declaring it unenforceable after first holding a public hearing.

Thus, the regulatory structure in respect of the EPAs is precisely parallel to the structure in respect of extensions of BC Hydro’s system. The Commission is intended to intervene and conduct public reviews only by exception.

The REAP process discussed above is well matched to this legislative structure. That is, because the REAP process allows the Commission to be apprised of proposed EPAs before they are issued, the need for the Commission to consider the general resource acquisition issues invoked by EPAs entered into consistent with previously described acquisition plans should be removed. Individual EPAs ought only to require review where they are not on their face within the scope

of a previously approved acquisition plan or the Commission has reason to believe that the manner in which they were entered into was inconsistent with its expectations when it approved the REAP of which they were a part.

It is respectfully submitted that this approach makes sense for all stakeholders. First, from the perspective of the Commission, it can undertake its review of the resource planning issues in the context of an overall plan (the REAP), as opposed to having to revisit these issues in the context of each individual contract. Once a public hearing with respect to a specific contract begins, it will be hard for the Commission to ignore the larger planning issues relating to the overall resource balance and the optimum way to acquire new resources, even though at a macro level, those issues are the same with respect to each of the EPAs. This is exemplified by BC Hydro's recent filing of 24 EPAs under cover of a letter dated April 8, 2004.[196] It makes much more sense to look at these as a package as distinct from holding individual hearings. The REAP facilitates this approach.

Second, from the point of view of IPPs, it is essential that they learn as early in the process as possible whether there is a significant regulatory concern with respect to any contracts they are entering into with BC Hydro. If each individual contract faces the prospect of regulatory review, significant transaction costs are added. As the IPPBC panel made clear, these are transaction costs that may be fatal to some projects and that will not facilitate the development of a competitive market for the supply of energy.[197]

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[196] Ex. B1-26.

[197] T21: 3876/3-3877/3.

Third, from BC Hydro's perspective, the REAP process permits BC Hydro to get on with its business as efficiently as possible and with an overall sense that the objectives it is seeking to serve are acceptable to the Commission.

For these reasons, BC Hydro respectfully submits that in this decision, the Commission should send a clear signal that it will only require a review of individual contracts in exceptional circumstances.

C. Specific Issue With Respect to the Substance of the REAP: Power Smart

BC Hydro submits that there is ample uncontradicted evidence to support the relief sought with respect to the energy acquisition and capital expenditure plans.

The Power Smart program was more controversial. BC Hydro believes it, too, should be approved in its entirety. Its rationale in this regard is set out next.

BC Hydro's Power Smart program received close scrutiny from a variety of perspectives. The IPPBC suggested that DSM is a greater component of BC Hydro's resource acquisition strategy than it should be. The Sierra Club suggested it was not a large enough component. The BCOAPO critiqued the Power Smart industrial load displacement incentives, while the JIESC questioned expenditures on commercial and residential programs.

BC Hydro believes its Power Smart programs provide the right DSM contribution to a diversified least-cost portfolio over time. The approach to developing Power Smart is not based on faith, but on a focused attempt to minimize long-term costs and risks. From BC Hydro's perspective, an investment in conservation by a household or business is just as much a private sector initiative designed to meet the province's energy needs as is the construction of new

generating facilities by an IPP. Both types of investments should be evaluated in a consistent and objective manner with a view to obtaining a resource portfolio that is as cost-effective as possible. BC Hydro believes that the expenditures identified in the Application and the REAP accomplish that objective.

To assess the Power Smart component of its resource portfolio, BC Hydro first sought to determine, through the *BC Hydro Conservation Potential Review 2002* (CPR),[198] the scope of the resource that could be obtained cost-effectively in theory, and then, with the intelligence contained in the CPR and other information, to develop programs designed to capture these benefits in practice. Having developed the programs, it then identified a means to implement them through the Power Smart 10-Year Plan[199] and rigorously evaluate them on an ongoing basis to ensure that the benefits anticipated are, in fact, delivered. A DSM Evaluation Summary and Plan was filed in this regard.[200]

The issues that arose regarding Power Smart's approach to DSM involved:

- the cost-effectiveness of its programs in general;
- application of the cost-effectiveness tests in program design;
- the relationship between Power Smart and Price Signals;
- the potential for over-estimating savings;

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[198] Ex. B1-2, Appendix H.

[199] Ex. B1-2, Appendix I.

[200] Ex. B1-2, Appendix M.

- various adjustments to calculations;
- allocation of portfolio-level costs to individual programs; and
- the possibility of BC Hydro pursuing a more aggressive DSM program.

Each of these issues is addressed in turn below.

1. Cost-Effectiveness Tests

Power Smart screens its programs using three cost-effectiveness tests. In each case, the tests estimate the present value of a stream of costs and benefits, the results of which can be stated in the form of a net present value, a benefit-cost ratio, or a levelized value, i.e., ¢/kWh or $/MWh. The appropriateness of these tests and their application were the primary issues discussed during the hearing.

(a) Total Resource Cost Test (TRC)

The primary screen employed by BC Hydro in assessing its programs is the TRC test. This test measures whether an individual program is efficient in the sense that the overall cost of delivering a given amount of energy services to customers is accomplished through a Power Smart program at a lower cost than the next least-cost alternative means of acquiring energy.[201] Thus, the test adds the costs incurred by BC Hydro to deliver the program and the costs incurred by the customer to implement it, and compares the sum of those costs to the alternative of purchasing and delivering power to the customer.[202] The Power Smart portfolio as a whole passes the TRC, with a benefit/cost ratio of 1.3 and a levelized cost of 4.4¢/kWh; with some

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[201] Ex. B1-2, Appendix I, p. 5.

[202] *Ibid*.

limited exceptions, all of BC Hydro's Power Smart programs pass it too, a result that holds even when portfolio-level costs are allocated to individual programs.[203]

(b) Utility Cost Test (UC)

BC Hydro also considers the UC test, which is narrower in scope than the TRC and simply considers the costs incurred by the utility itself—both program delivery costs and incentives paid to customers—in comparison to the avoided cost of purchasing and delivering power.[204]

BC Hydro believes this test is relevant to assessing the financial risks undertaken by it: placing a limit on the cost it is prepared to incur is an appropriate and prudent additional screen to impose on the Power Smart programs. Thus, BC Hydro believes that the UC test provides a useful perspective. The Power Smart portfolio has a UC benefit/cost ratio of 2.7 and a levelized cost of 2.1¢/kWh.[205]

(c) Ratepayer Impact Measure (RIM)

The third test considered by BC Hydro is the RIM. It compares the change in a utility's revenues with the change in its total costs (revenue requirements) resulting from a DSM program. Put differently, the RIM net benefit is the avoided cost of supply minus the sum of the utility's expenditures on DSM and the lost revenues from DSM; participant costs are excluded from the calculation, as they are with the UC.[206] If the amount of the revenue change differs from the amount of the cost change, rate levels may also change.[207] The RIM is also known as the "non-participants' test" because it indicates the effect on those customers who cannot or do not

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[203] Ex. B1-2, Appendix I, p. 28; Ex. B1-81.

[204] Ex. B1-2, Appendix I, pp.5-6.

[205] Ex. B1-81.

[206] Ex. B1-2, Appendix I, p.6.

participate in the program under consideration.[208] The Power Smart portfolio has a RIM benefit/cost ratio of 0.9 and a levelized value of 6.4¢/kWh.[209]

(d) The Difference Between TRC and RIM

The RIM test is one of equity, not efficiency. This distinction, though not accepted by all parties, is key to understanding the interplay between the tests used to screen Power Smart programs, particularly between the TRC and the RIM. Any program with a positive TRC (or a TRC benefit/cost ratio greater than 1) improves the efficiency of B.C.'s economy. It does this by meeting energy needs at least cost. This was confirmed by the IEP analysis, done independently of the Power Smart 10-Year Plan: IEP portfolio P1b, which examines the merits of continuing the level of activity in the current Plan, is the least cost system portfolio.[210] However, the TRC does not distinguish between winners and losers within the economy and it may be that a particular program provides substantial benefits to the few by imposing relatively minor expense on the many. To some, this may appear unfair, leading to a call for prescribed RIM ratios. However, there is no absolutely right answer with respect to the appropriate RIM threshold for all demand-side programs. Rather, it depends on an assessment of fairness in the context of the number and identity of beneficiaries and the number and identity of those who may be adversely affected by any individual program. A prescriptive approach to the RIM – i.e., that it not fall below 1 or some other ratio – would not do justice to the kind of contextual analysis that is required.

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[207] *Ibid*. See also Ex. C35-5, *CPUC Standard Practice Manual 2001*, p.13.

[208] *Ibid*.

[209] Ex. B1-2, Appendix I, pp. 6, 28; Ex. B1-81.

[210] Ex. B1-24, Part 6, pp. 19-21, 59.

(e) Rate Impacts vs. Bill Impacts

As calculated by BC Hydro, the RIM provides a directional estimate of a program's impact on rates. When the RIM is positive (in ratio terms, greater than 1; in levelized terms, less than the levelized avoided cost of supply), that is a signal that the DSM program will tend to decrease rates, and vice versa.[211] The signal will depend on a number of factors and vary from one sector to another. This follows from the relationship between the marginal cost of supply and the average rate within a given customer class: the greater the divergence between these two, the greater the RIM, assuming other things, such as program costs, remain equal.[212] What is important to appreciate is that the RIM does not measure bill impacts. From an electricity consumer's point of view, bills matter more than rates because the consumer's welfare depends on the benefit received from the energy, not on how much energy is actually consumed. It is for this reason that BC Hydro resists the IPPBC's suggestion that the RIM test should be used as a measure of efficiency. And it is for this reason that most other jurisdictions in North America consider the RIM, if at all, solely in the context of the equity issue, not the efficiency issue.[213]

2. Application of the Tests in Program Design

(a) The Programs Are Economic Under the TRC

As noted above, the majority of BC Hydro's programs in the Power Smart 10-Year Plan pass the TRC test. The only ones that do not are: (i) the Schools, Universities, Colleges and Hospitals (SUCH) program (TRC ratio of 0.9); (ii) Lighting Redesign (TRC ratio of 0.9); (iii) Range Conversions (TRC ratio of 0.9); and a residential pilot project run in Courtney, Comox and

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[211] Ex. C35-5, *CPUC Standard Practice Manual 2001*, pp.13-17, 33.

[212] *Ibid*.

[213] T21: T. Woolf, 3778/25-3779/18.

Quesnel (TRC ratio of 0.4).[214] However, BC Hydro explained that programs with a TRC benefit/cost ratio of close to 1 (i.e., 0.9) at the *Plan* stage are expected to show quantifiable non-energy benefits at the *business case* stage that would make the TRC benefit/cost ratio at least 1.[215] This would apply to the Lighting Redesign and Range Conversion (appliance) programs.[216] BC Hydro witnesses testified that in the case of the SUCH program, its TRC reflects the fact that early investments were driven more by the UC than the TRC; but going forward, the economics of all its efficiency measures will be such as to result in a TRC program ratio greater than 1.[217]

(b) The RIM Test and Equity Issues

i) In General

Given the predominantly positive TRC results, the only real question on the evidence is whether the rate impacts introduced by BC Hydro's programs are acceptable from an equity perspective. That requires consideration of the RIM results.

There was much discussion during the hearing of appropriate RIM formulas and ratios for DSM programs. However, it is important to understand that the RIM benefit/cost ratio is only a shorthand to express whether or not a project has a positive net present value. If it does, rates may go down because of the program; if it does not, rates may go up. If rates go down, energy bills must also. If rates go up, energy bills may go up or down, depending on the TRC results.[218]

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[214] Ex. B1-81: "Portfolio Costs Not Allocated"—ratios change slightly when portfolio costs are allocated.

[215] Ex. B1-7, BC Hydro response to BCUC IR 1.59.1.

[216] T14: 2258/4-7.

[217] T14: 2258/13-2259/1.

[218] T21: T. Woolf, 3780/21-3781/12; Ex. C35-5, *CPUC Standard Practice Manual 2001*, p. 13.

BC Hydro respectfully submits that ratios and limits on them should be very carefully approached, and this is particularly so with the RIM. Much mischief can be done with ratios and much unnecessary debate engendered by them, as the evidence of the IPPs make clear. The ERIM test developed by Mr. Belland on behalf of IPPBC[219] contributed nothing to the overall debate in this proceeding, because whether one uses the ERIM formula that he developed or the RIM formula more commonly used and employed by BC Hydro, the RIM net present value is unaffected and an assessment of whether rates are going up and down and by how much is also unaffected.[220] All that can be said is that the ERIM exaggerates program differences because of a leverage contained in the formula used to calculate it relative to the RIM formula. It in no way affects the judgment as to whether a program has a beneficial or negative impact on rates and it provides no additional information on whether, despite its rate impact, the program would likely increase or decrease electric bills.

Dr. Shaffer's evidence on the RIM was of somewhat more assistance to the Commission than Mr. Belland's. Dr. Shaffer made the point that where there are very few beneficiaries, the RIM test should be given more prominence and careful consideration to ensure that the class of beneficiaries is not too narrow in light of the costs that are imposed on the ratepayers.[221] Recognizing this, BC Hydro committed to limiting its large industrial incentive to programs with a positive RIM so that all non-participants would benefit,[222] as well as the participants themselves; it also sought to demonstrate that the two load displacement projects it had already undertaken were beneficial for all ratepayers.

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[219] Ex. C4-4.

[220] T20: 3695/20-3697/1.

It is important to note that equity can be addressed in various ways. Clearly, if non-participants in a particular program benefit from it, no significant equity issue arises. But even where they do not participate in and benefit from a particular program, they may be treated fairly if there are other programs available to them that are efficient in the sense of passing the total resource cost test, despite increasing rates for non-participants. Consider, for example, a program that: (i) is available to every customer; (ii) passes the total resource cost test; (iii) increases average rates; and (iv) lowers the average energy bill of all participants. For such a program, non-participants are adversely affected only because of their freely made choice to consume energy that is more expensive than conservation-based alternatives. There is nothing unfair about those particular consumers assuming responsibility for the costs associated with their decision.[223]

This principle can apply equally to diverse programs for different sectors of BC Hydro's customers, as long as there are some programs available to all customers. That is why BC Hydro has made a considerable effort to ensure it has cost-effective programs in the residential and commercial sectors, even though they may not pass the RIM test. U.S. regulators have recognized that such program diversity across classes is an important factor in mitigating the effect of rate increases. A case in point is the decision of the Iowa Utilities Board in the 2003 revenue requirement application of Interstate Power and Light Company (IPL). In commenting on the rate increase approved in that decision, the Board said:

> It is critical to note that there are means available to IPL customers to mitigate the impacts of rate increases. IPL has in effect an energy efficiency plan that contains several measures for customers of all classes to reduce and better manage their energy usage. A new IPL energy efficiency plan is currently

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[221] T20: 3673/20-3674/13, 3676/1-20.

[222] T13: 2042/4-8.

[223] Even Mr. Belland agreed to this proposition. See T21: 3860/3-3861/19.

> before the Board. The Board encourages all customers to carefully examine the available programs to see which ones might benefit them.[224]

ii) The Industrial Sector in General

In the industrial sector, on BC Hydro's evidence, the equity question is answered by the fact that all RIMs are positive or, in ratio terms, greater than 1. For the sector as a whole, the RIM is 1.2, or 1.1 even when portfolio-level costs are allocated.[225] However, that evidence is challenged by Dr. Shaffer and Mr. Belland, particularly as it relates to the load displacement program. Accordingly, their express comments on the industrial programs are discussed next.

Dr. Shaffer focused on the Canfor and Weyerhaeuser load displacement programs, which make up the bulk of BC Hydro's anticipated expenditures in the industrial sector during the test period. His view was that the benefits from the program were overstated, in that while he did not necessarily challenge their efficiency in the TRC sense, he thought they nevertheless had a sufficiently negative effect on rates that they ought not to have been undertaken.[226] Mr. Belland spread his criticisms more broadly and expressed reluctance to accept any program with a RIM less than one.

In the industrial sector, both Dr. Shaffer and Mr. Belland criticized BC Hydro's approach to load displacement programs because, in their view, BC Hydro had paid inadequate attention to the imminence of stepped rates. In BC Hydro's respectful submission, both Dr. Shaffer and Mr. Belland failed to understand BC Hydro's approach in this regard.

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[224] *Interstate Power and Light Company (Re)*, 225 P.U.R. 4th 165, 2003 Iowa PUC Lexis 140 at LEXIS *16-17

[225] Ex. B1-81.

[226] Ex. C10-3, pp. 13-14.

Mr. Marchant made it clear that, in fact, BC Hydro had considered the impact of stepped rates and expected that this impact would greatly reduce the need for incentives over time. This is not particularly significant in the context of the load displacement programs contemplated in F2005 and F2006 because those are programs to which BC Hydro is already committed and which, in any event, are total displacement programs that are unaffected by stepped rates, as both Dr. Shaffer and Mr. Belland agreed.[227] However, it is important that the Commission understand BC Hydro's commitment to minimizing the extent of the incentives, in light of the fact that 10% of consumption will be at market prices.

BC Hydro proposes to do this in two ways. First, in its business case review of applicants to industrial programs, BC Hydro will have an opportunity to fully understand its customers' anticipated savings and, thus, the incentives required. To the extent the stepped rate reduces the required incentive, BC Hydro will offer less. That is the source of the $60 million in savings that BC Hydro expects to result from the stepped rate program. Second, BC Hydro will ensure that nobody benefits twice from the incentives that are given by ensuring that the CBL is adjusted where an incentive is provided. Thus, a customer who accepts money from BC Hydro to displace its load will see its CBL reduced so that it must find further conservation measures in order to obtain any further market-based benefits. This will prevent double counting in favour of particular customers.[228]

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[227] T20: 3670/18-3671/20; T21: 3870/6-22.

[228] Ex. B1-7, BC Hydro response to BCUC IR #1.55.0; T13: 2038-39.

iii) Specific Criticisms of the Canfor and Weyerhaeuser Projects

Dr. Shaffer suggested that BC Hydro should have used a short-term mid-Columbia price to evaluate the avoided cost of energy achieved by the Canfor and Weyerhaeuser load displacement programs.[229] In BC Hydro's view, using a short-term price for the avoided cost of a long-term load displacement program is inappropriate. The only way that BC Hydro can meet long-term needs for customers such as Canfor and Weyerhaeuser is to acquire resources for the long term. BC Hydro explained its portfolio approach in this regard and Ms. Hemmingsen described the analysis that BC Hydro has gone through to determine that its portfolio is appropriate and that it is not desirable to be further exposed to short-term market prices.[230] The only contrary evidence is that of Mr. Craig, who suggested that greater short-term exposure was desirable and could save about $5 million; this conclusion, though, appeared subjective and arbitrary in nature and did not contain the level of rigour that would be appropriate to such a significant assessment.[231] Dr. Shaffer himself did not claim to have made the assessment, but rather was looking for an objective market price.[232] It is respectfully submitted that he used the wrong one, and the weighted average of the energy call prices, which is BC Hydro's actual cost of acquiring energy for the longer term or some other proxy for long-term prices, is more appropriate in this regard.

In fact, because of the vagaries of exchange rates, the two prices happen to converge right now. As Ms. Hemmingsen explained, electricity prices are forecast in U.S. dollars, and there has been considerable volatility in the Canada-U.S. exchange rate in the last year. When BC Hydro

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[229] Ex. C10-3, p. 10.

[230] T11: 1792/10-1794/12. See also Ex. B1-197 for a graphic demonstration of the volatility of short-term prices and the consequence of exposure to them.

[231] Ex. C35-5, p. 15.

[232] Ex. C10-3, p. 10.

forecast the $55/MWh cost, the exchange rate was about 62¢. But at the time the price was forecast for the Application and also at the time it was forecast to prepare for the Update, the Canadian dollar was worth 80¢ in U.S. currency. That affected the values of electricity translated into Canadian dollars and produced the outcome of $47.80/MWh. Subsequently, the Canadian exchange rate has moved in the opposite direction, and Ms. Hemmingsen testified that if BC Hydro were to now provide the same information that was filed with the Application, the $47.80/MWh would now be $54/MWh.[233] It would hardly be prudent for BC Hydro to submit a plan for either demand-side or supply-side resource acquisition that was based on a price subject to such short-term exchange rate variability.

Dr. Shaffer also criticized the Canfor and Weyerhaeuser assessment on the basis that it assumes that those industrial customers would not have implemented conservation measures on their own. Mr. Marchant and Ms. Van Ruyven made it clear that in terms of the load displacement program itself, an exhaustive assessment was done to determine whether or not either company would proceed in the absence of the incentives provided by BC Hydro.[234] Significantly, no one was able to provide any evidence based on direct contact with the companies or any other objective information that would suggest Mr. Marchant reached the wrong conclusion in this regard. Dr. Shaffer's evidence should be seen as a general and theoretical proposition that it is difficult to assess what individual customers might do in any particular circumstance. Indeed, his proposition was carefully framed in that way, *viz*.: "one simply cannot be certain what Weyerhaeuser and Canfor, taking all factors including non-electricity benefits and costs into

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[233] T14: 2249/18-2250/17.

[234] T14: 2259/17-2269/13.

account, would have in fact done."[235] The analysis should not be taken as a specific comment with respect to the reliability of BC Hydro's assessment in the particular circumstance of Canfor and Weyerhaeuser because Dr. Shaffer made no inquiries of a specific nature that would have permitted him to make that assessment, nor did any other witness who appeared in the proceeding.

In his direct evidence, Dr. Shaffer made the assumption that in the absence of load displacement incentives, Canfor and Weyerhaeuser would have implemented some conservation measures and reduced electricity purchases by 10%.[236] No basis was provided for that assumption and it is not at all clear that such opportunities existed at either facility. Even if they did, it is entirely possible that if the productive processes at Canfor and Weyerhaeuser grow over time, those manufacturers will again require additional resources and at that time have an incentive to increase their conservation efforts.

iv) Non-Industrial Programs

With respect to non-industrial programs, there was some considerable discussion of whether there ought to be minimum RIMs at some ratio less than one. Mr. Hobson testified that all of the current programs had a RIM benefit cost ratio of at least 0.6 and he had difficulty conceiving that BC Hydro would proceed with a program with a more adverse RIM than that ratio implied. The Chair explored the impact of employing different cut-offs on the existing programs and various exhibits were filed in that connection.

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[235] Ex. C10-3, p. 13.

[236] Ex. C10-3, p. 11.

In BC Hydro's respectful submission, the Commission ought to be cautious about establishing an arbitrary RIM benefit cost ratio. For the reasons outlined above, applying the RIM test to prevent projects that would otherwise pass the TRC from proceeding is to impose additional costs on BC Hydro's customers as a whole. A residential program with a low RIM that offers very broad participation potential may be fairer than a very focused industrial or even commercial program in which few can participate that has a higher RIM. There will always be an element of judgment in making this trade-off. While BC Hydro would greatly value the Commission's qualitative comments on how these judgments should be made, it urges the Commission not to create prescriptive, numerical-based limitations that will encourage arbitrary accounting procedures and discourage nuanced program optimization. Generally, BC Hydro should as free as possible to manage the specifics of the programs so as to achieve the maximum returns at the least cost. This "information framework" approach – by which Power Smart projects that do not include rates or conditions of service need not be filed for Commission approval, but are subject to prudency review[237] – has worked well in the past and has provided BC Hydro the flexibility to modify the programs and projects as required.

3. The Role of Price Signals

When held up to close scrutiny, it is clear that what Dr. Shaffer and Mr. Belland were really saying was that at market prices, they hoped that no Power Smart programs would be required at all. They again referred to the stepped rate proposal in this regard. However, the stepped rate does not introduce a market signal for anything other than the top 10% of eligible customers' load. As Dr. Shaffer acknowledged, he prefers the general type of rate design captured in BC Hydro's "shopping credit" proposal that was a part of its original stepped rate proposed

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[237] Ex. B1-142.

design.[238] That approach did not ultimately find favour with any of BC Hydro's customers, the Commission or the Government and, thus, BC Hydro is not planning its resource acquisition in the way it would if the shopping credit proposal had been accepted. That is simply recognizing reality and, in the circumstances, is the only responsible and prudent approach to take. Put another way, it would be imprudent to assume the price signal available under the shopping credit for future planning in the current environment in the way that Dr. Shaffer suggests.

Dr. Shaffer's preference for the shopping credit or similar proposal is understandable because he is a strong believer in the effectiveness of appropriate price signals. While BC Hydro similarly believes that sending an accurate price signal is important, it is less persuaded that it is sufficient. Such price signals exist at the margin in the residential sector where the cost of incremental consumption, in fact, considerably exceeds the cost of new supply; and in the commercial sector where the two are, roughly speaking, equal. Nevertheless, BC Hydro believes that commercial and residential Power Smart programs are still necessary because of the many non-price-related market failures that exist in both sectors.

Similarly, in the industrial sector, merely sending a price signal based on market prices is not enough. Knowledge gaps, capital scarcity and high hurdle rates, to name a few, all affect industry's willingness to invest in conservation initiatives and would result, even with efficient pricing, in lost conservation opportunities that would benefit all customers. In this regard, Mr. Woolf stressed the importance of empirical evidence over theory,[239] noting that "when it comes to day-to-day decision-making, many customers, even industrial customers, they're

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[238] T20: 3669-71.

[239] T21: 3789-3792.

thinking about the next quarter, the next half of the next year. They're not thinking about three, four or five years from now."[240] As to Weyerhaeuser and Canfor specifically, Mr. Marchant emphasized that an exhaustive assessment was done to determine whether either company would invest in turbo generators in B.C. without assistance from BC Hydro.[241] Accordingly, BC Hydro does not accept that the stepped rate or, indeed, any pricing mechanism, taken alone, is sufficient to obtain all the efficient conservation that is available in British Columbia from the industrial sector or, indeed, any other sector of its customers

4. Potential for Over-Estimating Savings

Dr. Shaffer also relied on a U.S. econometric study to make a general point that utilities tend to overestimate DSM savings.[242] This testimony from diverse US jurisdictions suffers from the self-acknowledged weakness that it treats all DSM projects as the same when in fact they are not. It also assumes that all utilities have the same incentives with respect to the reporting estimates when, again, they do not, and when the study authors acknowledge that many utilities within the sample have "perverse incentives" to maximize spending for conservation regardless of impact and to over-report on savings.[243] No such incentives were alleged by Dr. Shaffer to exist in B.C.; indeed, he acknowledged that, to the extent that perverse incentives arise from a regulatory regime that allows a return on investment for both demand-side and supply-side investments

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[240] T21: 3797/8-12.

[241] T13: 2169/13-2171/16; T14: 2267/13-2269/13.

[242] Ex. C10-3, p. 7.

[243] Ex. C10-3, p. 8; T20: 3683/23-3684/4.

(sometimes referred to as the Averch-Johnson effect), they do not exist with a publicly-owned utility such as BC Hydro.[244]

The relationship between DSM expenditures and energy efficiency as measured in these studies is complex and subject to a great many different influences. It is simply not possible to speculate usefully about whether a relationship that may exist in the United States can be said to exist here. In these circumstances, BC Hydro's own evaluation methodologies provide a much better assessment of the extent to which it has accurately forecast energy savings than do imported econometric studies which have only been presented and debated third-hand. Expert testimony presented as hearsay is no substitute for the direct evidence of the Power Smart witnesses, to the effect that the 60 projects that have thus far been evaluated have delivered 106% of the anticipated savings they were designed to produce.[245] Furthermore, regarding the Power Smart Partner projects—whether industrial or commercial—the incentive payments are staggered, such that if measurement and verification shows that the savings are not achieved, BC Hydro can hold back the last 25% and may be able to claw back some of the 75% already provided.[246] None of that evidence was challenged on cross-examination.

5. Adjustments to Calculations

Mr. Belland took aim at a number of calculations for the DSM programs. His first point had to do with an alternative approach to accounting for energy savings using mid-year, rather than end-year, "run rates"—that is, the annualized rate of savings.[247] His purpose in making the

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[244] T20: 3684/24-3685/7.

[245] T13: 2142/17-2143/11.

[246] T11: 1765/21-1766/1766/12.

[247] Ex. C4-4, p. 18.

adjustment was to correct for the fact that projects may start or end part way through the year. The evidence showed that the effect of this particular point, if valid, is a rounding error.[248] Mr. Belland also conceded that he did not make a similar adjustment to the expense side and did not provide any degree of assurance that a mid-year estimate of acquired savings would properly align with his assumptions about the timing of expenses.[249] Thus, even the 0.02% impact on the RIM ratio that he identified in Table 2 of his direct evidence is likely an overstatement.

Mr. Belland also made a point with respect to the redundancy of the GHG adder.[250] During cross-examination by Mr. Fulton, Mr. Hobson conceded that this constituted double counting if green energy call values are used in the analysis and that an adjustment to the cost-effectiveness tests would be appropriate where this occurred. The adjustment was made during the hearing and shown to be *de minimus*: the portfolio ratio for the UC changes from 2.7 to 2.6, and the portfolio ratios for the TRC and RIM remain unchanged (to one decimal place) at 1.3 and 0.9.[251]

Mr. Belland argued that BC Hydro erred by assuming flat retail rates[252], but on cross-examination conceded that the real issue was the spread between rates and future prices.[253] He filed no evidence on how that spread might evolve over time.

Mr. Belland also suggested that there ought to be a risk-adjusted discount rate.[254] However, the much more common approach is to adjust values, not discount rates, so as to avoid having to

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[248] Ex. C4-4, p. 20, Table 2.

[249] T21: 3862/26-3863/8.

[250] Ex. C4-4, p. 20.

[251] Ex. B1-101.

[252] Ex. C4-4, pp. 21-23.

[253] T21: 3863/9-15.

[254] Ex. C4-4, p. 23.

apply a different discount rate to every project. In any event, Mr. Belland was unconvincing in suggesting that demand-side projects alone were risky and acknowledged that there are significant risks associated with IPP purchases too. Mr. Belland said his examination of the IEP's treatment of risk was "cursory" and gave no indication that he had quantitatively or even qualitatively analyzed the relative risks with any degree of rigour.[255]

In summary, Mr. Belland did not provide a basis for anything other than trivial adjustments to the net present value results of the cost-effectiveness tests for the Canfor and Weyerhaeuser load displacement programs.

Based on this, BC Hydro does not believe that the evidence of Dr. Shaffer and Mr. Belland seriously calls into question its determination that the rate impact of the Canfor and Weyerhaeuser projects is beneficial to all other customers by contributing energy at a cost lower than any other reasonable alternative. It is possible to argue about how much the benefit is, but so long as it is positive, there is no reason for non-participating customers to resent the cost savings that Canfor and Weyerhaeuser are able to achieve. Thus, even if the Commission had considered the Canfor and Weyerhaeuser proposals in advance, BC Hydro believes that they should have been approved; going forward, it thus sees no reason that the Commission should discourage comparable projects. Of course, the Commission has the commitment of BC Hydro that large incentive projects will only be undertaken where they have a positive RIM.

6. Allocation of Portfolio-Level Costs to Individual Programs

An issue arose with respect to the allocation of general program costs to specific projects. BC Hydro was firm that these program costs benefit the Power Smart Plan generally and that it is

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[255] T21: 3863/16-3866/21.

very difficult to isolate them to specific programs. Certainly, in determining whether individual programs should continue, the incremental costs of the programs are the important thing in assessing the efficiency of new investments in them. Thus, particularly in the context of the TRC test, burdening programs with overall costs that are not specific to them may lead to a suboptimal result. In the end, the allocation issue is probably not of great significance if over-reliance on the fairly arbitrary benefit cost ratios developed under RIM does not occur.

7. The Possibility of Pursuing a More Aggressive DSM Program

The evidence of Tim Woolf on behalf of Sierra Club suggested that, far from BC Hydro pursuing too much in the way of conservation resources, it could be pursuing even more. That analysis was based in part zero capacity savings (both transmission and distribution) being attributed to Power Smart. BC Hydro acknowledged that such savings were not accounted for in the Power Smart 10-Year Plan,[256] the effect of which is to understate the benefits under the total resource cost test (in ratio terms, to lower the B/C ratio), the primary measure for screening DSM options.

However, in the IEP, a system portfolio analysis, the capacity reductions associated with Power Smart were taken into account, i.e., factored into the timing of new transmission infrastructure,[257] the effect of which is to lower the present value of the portfolio costs. This contributes to making the portfolio with Power Smart 2 the least cost current planned acquisition portfolio.[258] Mr. Hobson agreed that this made the 10-Year Plan estimates "conservative."[259]

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[256] T11: 1670-72.

[257] T11: 1676.

[258] Ex. B1-24, Vol. 3, p. 59, Fig. 3.1.

[259] T11: 1678.

Mr. Woolf's analysis was also based in part on the non-monetization or non-quantification of non-energy benefits, the effect of which is to understate the benefits from all the cost tests. Mr. Hobson acknowledged that there could be a range of such benefits associated with energy efficiency measures, including operation and maintenance savings, productivity improvements, and increased comfort; but he said that such benefits are difficult to quantify at this time.[260] This also makes the TRC estimates conservative.

Mr. Woolf's analysis was also based on the possibility of electricity freed up from Power Smart being available for export, thus increasing trade revenues. Ms. Hemmingsen acknowledged this possibility, but only to the extent that the freed up power did not work to defer another (lumpy) resource addition.[261] She noted specifically that Power Smart 3 and 4 would defer planned Interior-to-Lower Mainland transmission.[262]

Finally, Mr. Woolf acknowledged that his comments were restricted to Power Smart 2 and agreed that, if the demand/supply balance were to unfold in such a way that a more aggressive Power Smart program were required (e.g., if sufficient cost-effective IPP power failed to materialize), BC Hydro had contingency plans in the form of Power Smart 3, 4 and 5.

For all of the above reasons, BC Hydro believes that the Power Smart Plan, including the possibility of ramping up the Plan's programs in future REAPS if required, provides the right contribution to a diversified least cost portfolio over time. BC Hydro accordingly requests approval of the Power Smart 10-Year Plan pursuant to s. 45(6.1)(c) and s. 45(6.2) of the Act.

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[260] T11: 1680-81.

[261] T11: 1686-87.

[262] T11: 1689.

D. Proposed Order

BC Hydro requests that the Commission make the following determinations:

(i) The capital expenditures contemplated in the REAP are in the interest of BC Hydro's ratepayers.

(ii) The expenditures contemplated in the REAP to reduce the demand for energy are in the interests of BC Hydro's ratepayers.

(iii) The expenditures contemplated in the REAP to acquire energy from other persons are in the interests of BC Hydro's ratepayers.

BC Hydro requests that the Commission make the following orders:

(iv) The expenditures contemplated in the REAP for F2005 and the first quarter of F2006 are recoverable in future rates.

(v) Future resource acquisition expenditures made in consequence of the F2005 400 GWh energy call are recoverable in future rates, provided that call is conducted generally in accordance with the procedures employed in previous energy calls and the resulting energy purchase agreements are filed with the Commission pursuant to section 71 of the Act.

VI. OTHER ISSUES

In addition to the four applications before the Commission for decision in this proceeding, BC Hydro would like to comment on two other areas. The first is the regulatory status of the service level agreements that are currently being negotiated between BC Hydro and BCTC. The second is the timing and process associated with the various steps arising from the re-regulation of BC Hydro's rates and the establishment of BCTC. Each is dealt with in turn.

A. BCTC Service Level Agreements

At the close of the oral phase of the hearing the Chair requested that in its Argument BC Hydro address questions regarding the Service Level Agreements between BC Hydro and BCTC.[263] However, BC Hydro does not believe the record in this proceeding has been sufficiently established to take a final position with respect to those agreements. None had been finalized during the oral phase of the hearing, and in consequence none are in evidence. The questions posed by the Chair regarding the agreements are ones which may well turn on the specific terms of the agreements. BC Hydro's expectation is that the agreements are not ones that the Commission has jurisdiction to approve,[264] but until the agreements are final it cannot say more than that. BC Hydro expects to file the Service Level Agreements when they are finalized, and articulate its responses to the questions posed by the Chair at that time.

B. Proposed Regulatory Schedule

The revenue requirement hearing and the associated applications within it are a first step in the ongoing evolution of the re-regulation of BC Hydro. In this section, BC Hydro outlines what it sees to be the key additional processes that will take place over the next two years and the timing

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[263] T21: 2993/23 to 3994/1.

associated with them. To the extent possible, they are presented in chronological order. However, given the significant uncertainties involved with a number of these processes and BC Hydro's lack of control over a number of variables, the dates are rough estimates only.

1. BCTC OATT Application

BCTC has indicated that it will be filing its OATT application this summer. BC Hydro expects that application to establish new rates for wholesale transmission service effective April 1, 2005. The Commission's decision with respect to that application will complete the transition of operation of the transmission system to BCTC and will determine a component of what amount, if any, will be placed in the BCTC Transition Deferral Account.

2. BCTC Revenue Requirement Application

BCTC has indicated that it expects to file a revenue requirement application for F2006 in the fall of 2004. The Commission's decision with respect to that application will determine any remaining amounts that need to be placed in the BCTC Transition Deferral Account.

3. BC Hydro Application to Clear the VIGP/GSX Deferral Account

BC Hydro will make an application to clear the VIGP/GSX costs deferral account shortly after a final decision with respect to those projects. BC Hydro anticipates that this application will be filed in late 2004 or early 2005 and that its application will not seek recovery of any costs associated with VIGP/GSX prior to F2007.

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[264] See Ex. B1-7, BC Hydro response to BCUC IR #1.76.8.

4. Stepped Rate Design and Implementation

BC Hydro hopes to be in a position to apply for approval of the Tier 2 price for stepped rates and the CBL for every customer by December 2004. The nature of the process required in connection with that application will depend on the degree of consensus that has been reached with customers.

5. 2005 REAP

BC Hydro plans to file a new REAP in February 2005 and every February thereafter.

6. General Tariff Application

BC Hydro plans to file a general tariff application dealing with rate design and related matters in the Spring of 2005. Depending on the degree of consensus achieved with respect to stepped rate design, that proceeding could also be employed to resolve any contentious aspects of the stepped rate design.

7. 2005 IEP

BC Hydro proposes to file its biannual IEP in the Summer of 2005 and every other summer thereafter to provide context for its own budgeting process through the fall and the preparation of a REAP for filing with the Commission the following February.

8. F2007 Revenue Requirement Application

BC Hydro proposes to file its next revenue requirement application in February of 2006 at the same time as its REAP application for that year.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

LAWSON LUNDELL

Per: _____
Chris W. Sanderson, Q.C.

Per: _____
Jeff Christian

Per: _____
John A. Kleefeld

Per: _____
Ian D. Webb

Schedule A – Table of Concordance to Issues List

The following table indicates where issues identified on the final Issues List to this proceeding are specifically addressed in BC Hydro's Argument. The Argument, and this schedule, does not address issues from the Issues List that were not pursued by either counsel or commissioners in the oral phase of the proceeding or which seemed in BC Hydro's judgment to not be in dispute. As well, some issues from the Issues List are addressed implicitly in the discussion of other issues, and do not appear in this schedule. Finally, this schedule does not refer to issues that are covered in the Argument because they came up in the course of the hearing but never were on the Issues List.

Issue (Revised Issues List: Exhibit A-33)	Page Number in Argument
1.1	Part IV (61-83)
1.3 (2nd bullet)	45-46
1.4	Part V (84-92)
1.5	Part V (84-92)
1.6	36-42
1.7	7-9; 15-25; 36-42
1.9 (1st bullet)	44-45
1.10	30-36; 46-47; 52
2.1	55-57
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2.2.2	19-22
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2.4.2	16-19
2.6	53-54
2.7	Part IV (61-83)
2.8 (2nd bullet)	55-57
2.9 (2nd bullet)	65; 77-78
3.1 (1st bullet)	36-40
3.2 (1st bullet)	38
3.3 (1st bullet)	39
3.4	46
4.1	47
4.2.1 (1st 12 bullets)	48-51; 92-113
4.2.2 (last bullet)	112-113
4.2.3	50-51; 101-105; 107-108
4.6	Part V (84-113)
5.2	35
5.4	38-40
5.5	39
5.6	22
5.7	24-25
6.2.1 (2nd bullet)	42; 44-45
6.2.3	43-44
6.2.4 (1st bullet)	38
6.3.2 (1st bullet)	115
7.1	52
7.2	38-40
7.5 (in part)	52
7.7	55
7.9	52
8.1 (in part)	Part V (84-113)
10.1	21-22
10.2 (in part)	23-24; 38; 44-46; 71-73
10.3 (in part)	16-21; 24-25; 53-55
11.1 (in part)	Part V (84-113)
12.1 (in part)	16-21
13.1 (in part)	112-113

Schedule B – Issues Raised by Commission Chair at Close of Hearing

The following issues were identified by the Chair at the close of the oral phase of the hearing, and are addressed in BC Hydro's Argument.

	Issue	Page Number in Argument
1.	Is the Utilization and Credit Risk Deferral Account within scope of section 6 of Special Direction #9?	Not addressed as is a BCTC Application issue.
2.	Commission's jurisdiction regarding service level agreements.	115
3.	Prudency test for HDA and NHDA.	80-81
4.	Depreciation rates for Burrard in light of Ex. A-50	25
5.	Commission jurisdiction regarding FRSR reserves and/or amortization.	16-21
6.	Evidentiary basis for commission-determined capital structure for BC Hydro.	21-22
A.	Commission jurisdiction regarding capital structure of BC Hydro.	21-22
B.	Commission jurisdiction regarding Heritage Payment Obligation and HDA, as proposed by BC Hydro.	67-70; 73-74

Schedule C – List of Authorities Referred To

1. MacAulay and Sprague, *Practice and Procedure Before Administrative Tribunals*, Looseleaf (Toronto: Thompson Canada, 2002)

2. Priest, *Principles of Public Utility Regulation* (Charlottesville, Virginia Michie Company, 1969)

3. *British Columbia Hydro & Power Authority v. British Columbia (Utilities Commission)* (1996), 20 B.C.L.R. (3d) 106 (C.A.)

4. *Hemlock Valley Electrical Services Ltd. v. BCUC* (1992), 66 B.C.L.R. (2d) 1 (C.A.)

5. *Interstate Power and Light Company (Re)*, 225 P.U.R. 4th 165, 2003 (Iowa PUC)

6. *Office and Professional Employees' Int'l Union et al v. B.C. Hydro et al*, 2004 BCSC 422

BC HYDRO UNDERTAKING

BC HYDRO REVENUE REQUIREMENT HEARING
2004/05 AND 2005/06

HEARING DATE

Wednesday, June 9, 2004

TRANSCRIPT REFERENCE

Volume 20, pages 3447-3451

REQUESTOR: BCUC Counsel

QUESTION

Update BC Hydro's revenue requirements forecasts as discussed in transcript.

RESPONSE

Please see attached the June Financial Undertaking.

1 Introduction

This undertaking was prepared at the request of the Commission to identify the impact on Schedules A-D to the Financial Forecast contained in Chapter 2 of the Application to reflect:

1. the completion of final financial statements for F2004,

2. the availability of actual load data to the end of F2004, and

3. an update of any variables that were modified between the original application and the Revised Evidentiary Update (EU) filed April 2, 2004 for which more current data was available.

The three most significant changes reflected in the June Financial Undertaking are new water flow and load requirement information together with new forward energy market price information.

Water inflows, based on the June 1, 2004 Water Supply Forecast, are expected to be 89 per cent of normal in F2005, whereas the EU was based on the January 1, 2004 Water Supply Forecast of 94 per cent of normal. Average market energy purchase prices, based on the June 2004 forward curves, have increased from the prices used in the EU. Average natural gas prices at Sumas have increased by as much as 10% and 18% for F2005 and F2006 respectively, while average Mid-C electricity prices have increased by as much as 22% and 16% for F2005 and F2006, respectively. These two factors have combined to increase forecast energy costs.

Load requirements have also been adjusted to account for the higher actual loads compared to forecast for F2004 on the assumption that the higher loads in F2004 resulted from sustainable increases in demand. No assessment of that assumption has been performed. Rather, a higher baseline for load growth in F2005 and F2006 was simply assumed. BC Hydro is currently working on the update to the Load Forecast and this adjustment to the baseline may not reflect the actual changes that are made to the final Load Forecast, expected to be completed in the fall. The net impact of this adjustment is to increase the revenue

requirements in the test years as the additional revenue from the increase in load is more than offset by the incremental cost of supplying the increased load.

All relevant A to D schedules, which have changed from the Revised Evidentiary Update, are included in the June Financial Undertaking. The relevant schedules have also been updated with F2004 actual information. As set out in the Schedules, if all of this information were employed in determining BC Hydro's revenue requirement, the required increase for F2005 would rise to 12.7% followed by a reduction of 1.55% in F2006.

2 Pro Forma Consolidated Statements

Table 2A-1 is a summarized pro forma statement of operations of BC Hydro based on the June Financial Undertaking. A rate increase of 8.9% in F2005 (i.e., 7.23% already approved on an interim basis plus an additional 1.67% increase assumed for the purposes of this forecast to be effective November 1, 2004), the same as assumed in the April 2004 Revised Evidentiary Update, has been included. The full income statement is shown in Schedule A-1.

Table 2A-1. Pro forma Statement of Operations

($ millions)	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Equity	**$2,722**	**$3,037**	**$3,128**
Domestic			
Revenues	2,553	2,758	2,796
Inter-segment revenues	62	124	140
Expenses	(2,696)	(2,662)	(2,636)
	$(81)	**$220**	**$300**
Trade Income	$158	$89	$91
Net Income before transfers to RSA/	**$77**	**$309**	**$391**
Transfer from RSA *(Note 1)*	21	-	-
Net Income	**$98**	**$309**	**$391**
Allowed rate of return on equity	14.33%	13.91%	13.91%
Allowed Net Income	$396	$425	$436
Requested rate increase (%)	N/A	8.90%	N/A

Based on this updated forecast, BC Hydro's revenue shortfall will be $116 million and $52 million for F2005 and F2006, respectively.

3 Discussion of Financial Forecasts

3.1 BC Hydro Equity

The current forecast equity and the components that make up equity for F2004 to F2006 are shown in Table 2A-2.

Table 2A-2. Equity

($ millions)	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Retained earnings at beginning of year	$1,609	$1,634	$1,925
Net income	98	309	391
Payment to the province	(73)	(251)	(309)
Asset retirement obligation adjustment	-	233	-
Special dividend to the province for BCTC	-	-	(20)
Retained Earnings at End of Year	**$1,634**	**$1,925**	**$1,987**
Deferred revenue	$276	$293	$313
Contributions arising from the Columbia River Treaty	193	184	175
Contributions in aid of construction	619	635	653
Equity	**$2,722**	**$3,037**	**$3,128**
Actual/forecast rate of return on equity	3.60%	10.17%	12.50%
Allowed rate of return on equity	14.33%	13.91%	13.91%
Allowed net income	$396	$425	$436
Actual/forecast net income	$98	$309	$391

Note that the $120 million provision for GSX and VIGP expenditures in the F2004 financial statements has a minimal impact on the revenue requirements. The only impact is a reduction in equity and a corresponding decrease in the allowed net income and revenue requirement of $2.5 million (approximately a 0.1% rate impact). The reduction in the revenue requirement is determined by taking 15% of the reduction in net income (the remaining 85% relates to the reduction in the Payment to the Province) and multiplying this value by BC Hydro's allowed rate of return of 13.91%. ($120 million x 15% x 13.91% = $2.5 million).

It should also be noted that the decrease in retained earnings is partly offset by the higher than forecast Contributions in Aid of Construction balance. As a result total equity at

March 31, 2004 was only $8 million lower than forecast in the Revised Evidentiary Update. The lower than forecast equity has a $1 million impact on the revenue requirement ($8 million x 13.91% = $1 million).

3.2 Domestic Revenues

The adjustments to the Load Forecast for the test years reflect the variance between actual and forecast sales for F2004 carried forward and increased/decreased by the annual growth rate in the respective rate categories. Actual sales volumes in F2004 for the large industrial category were 704 GWh higher than forecast in the Application and actual sales volumes for the light industrial and commercial category were 228 GWh higher than forecast. The variance in the residential and other energy categories, totaling less than 20 GWh, were not carried forward as the variances were insignificant.

Changes in domestic revenues from the EU for F2005 and F2006 are shown in tables 2A-3 to 2A-6. The variance in revenues is due to the increase in forecast sales due to the adjustments in the load described above.

Table 2A-3. Domestic Revenues, F2005

($ millions)	**F2005 June Financial Undertaking**	**F2005 Revised Evidentiary Update Forecast**	**Variance**
Residential	$1,050	$1,050	$-
Light industrial and commercial	988	976	12
Large industrial	568	542	26
Other energy sales *(Note 1)*	72	72	-
	$2,678	**$2,640**	**$38**
Other utilities *(Note 2)*	$19	$19	$-
Miscellaneous	61	61	-
Total	**$2,758**	**$2,720**	**$38**

Notes:
1. Includes sales to City of New Westminster, Aquila Networks Canada, Irrigation and Street Lighting customers.
2. Other utilities under long-term contracts including Seattle City Light pursuant to the Skagit Valley Treaty agreements.

Table 2A-4. Domestic Sales Volumes, F2005

(GWh)	F2005 June Financial Undertaking	F2005 Revised Evidentiary Update Forecast	Variance
Residential	15,836	15,836	-
Light industrial and commercial	17,232	17,003	229
Large industrial	15,435	14,733	702
Other energy sales *(Note 1)*	1,404	1,404	-
	49,907	**48,976**	**931**
Other utilities *(Note 2)*	310	310	-
Total	**50,217**	**49,286**	**931**

Notes:
Refer to notes for Table 2A-3.

Table 2A-5. Domestic Revenues, F2006

($ millions)	F2006 June Financial Undertaking	F2006 Revised Evidentiary Update Forecast	Variance
Residential	$1,073	$1,073	$-
Light industrial and commercial	1,009	996	13
Large industrial	567	540	27
Other energy sales *(Note 1)*	73	73	-
	$2,722	**$2,682**	**$40**
Other utilities *(Note 2)*	$19	$19	$-
Miscellaneous	55	55	-
Total	**$2,796**	**$2,756**	**$40**

Notes:
Refer to notes for Table 2A-3.

Table 2A-6. Domestic Sales Volumes, F2006

(GWh)	F2006 June Financial Undertaking	F2006 Revised Evidentiary Update Forecast	Variance
Residential	16,063	16,063	-
Light industrial and commercial	17,433	17,202	231
Large industrial	15,297	14,604	693
Other energy sales *(Note 1)*	1,428	1,428	-
	50,221	**49,297**	**924**
Other utilities *(Note 2)*	310	310	-
Total	**50,531**	**49,607**	**924**

Notes:
Refer to notes for Table 2A-3.

3.3 Intersegment Revenues

Table 2A-7 identifies the difference between intersegment revenues in the updated forecast and those included in the Revised Evidentiary Update.

Table 2A-7. Intersegment Revenues, F2005 to F2006, Change from Prior Forecast

($ millions)	F2005	F2006
Total Intersegment Revenues – June Financial Undertaking	$124	$140
Total Intersegment Revenues – Revised Evidentiary Update	125	116
Increase (Decrease) in Intersegment Revenues	**$(1)**	**$24**

Forecast intersegment revenues for F2005 are similar to those forecast in the Revised Evidentiary Update. The increase in forecast intersegment revenues for F2006 is largely due to an increase in the net sales to Powerex of trade account energy. The Trade Account balance at the end of F2004 was higher than forecast. This increase in energy in the Trade Account is expected to be taken by Powerex in F2006. The trade account is projected to be fully drawn down by the end of F2006.

Table 2A-8 summarizes the foregoing.

Table 2A-8. Intersegment Revenues, F2004 to F2006

($ millions)	F2004 Actual	F2005 Forecast	F2006 Forecast
Net sales to Powerex - Future Use *(Note 1)*	$ –	$60	$73
Point-to-point wheeling charge to Powerex *(Note 2)*	39	50	53
Point-to-point wheeling charge to BC Hydro *(Note 3)*	12	12	12
Allocation of BC Hydro corporate costs to Powerex *(Note 4)*	2	2	2
Foreign exchange gain on Trade Payable balance – BC Hydro to Powerex *(Note 5)*	1	–	–
Mark to market gain – BC Hydro to Powerex *(Note 6)*	8	–	–
Total Inter-segment Revenues	**$62**	**$124**	**$140**

Notes:
1. These sales relate to a return of energy bought by Powerex in prior periods to enable future sale. These revenues are eliminated against trade cost of energy on consolidation.
2. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation.
3. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment. These revenues are eliminated against domestic cost of energy on consolidation.
4. These revenues relate to an allocation of corporate costs to Powerex and are eliminated against trade income on consolidation.
5. This relates to the foreign exchange gain on the payable to Powerex. Powerex would have a corresponding loss on their receivable. The receivable relates to energy purchased to enable future sale by Powerex and sold to BC Hydro when brought into the system.
6. This relates to a mark to market gain. Powerex would have a corresponding loss.

3.4 Domestic Cost of Energy

The most significant differences in domestic cost of energy between the Revised Evidentiary Update and the June Financial Undertaking are:

- The forecast water inflows for the February to September 2004 water year have declined from 94 per cent of normal in the Revised Evidentiary Update to 89 per cent of normal based on the June 2004 water supply forecast. This has the impact of reducing low cost hydro generation and increasing higher cost sources of supply.

- Electricity and natural gas market prices have increased. Average Mid-C forward electricity prices have increased by approximately 22 per cent and 16 per cent for F2005 and F2006 respectively, while average forward gas prices at Sumas have increased by as much as 10 per cent and 18 per cent for F2005 and F2006 respectively. This has the impact of increasing the cost of market purchases of electricity and natural gas.
- Domestic load volumes have increased as discussed in Section 3.2, pages 2-3. This increases the supply required to meet the increase in load.

Table 2A-9 shows the difference between the domestic cost of energy in the June Financial Undertaking and the domestic cost of energy in the Revised Evidentiary Update. The breakdown of the domestic cost of energy forecast is provided in Schedule A-9.

Table 2A-9. Domestic Cost of Energy, F2005 to F2006, Change from Price Forecast

($ millions)	**F2005**	**F2006**
Domestic cost of energy – June Financial Undertaking	$1,057	$995
Domestic cost of energy – Revised Evidentiary Update	906	865
Increase in domestic cost of energy	**$155**	**$130**

The increase in the forecast of domestic cost of energy in F2005 and F2006 is primarily due to an increase in market electricity purchase volumes and an increase in the price of energy purchases. Approximately half of the increase from the Revised Evidentiary Update in domestic cost of energy is due to higher purchase volumes and the other half of the increase is due to higher market prices for energy purchases. The increase in market electricity purchase volumes is due to the increase in domestic load, as discussed in Section 3.2, and to the decrease in hydro generation, including exchange net[1], due to the lower forecast water inflows. While the forecast for F2006 assumes normal water inflows, hydro generation including exchange net[1] is now lower than was forecast in the Revised Evidentiary Update

[1] Exchange net relates to non-treaty storage agreements with Bonneville Power Administration, Kootenay Canal Plant Agreement with Aquila Networks Canada and Keenleyside Entitlement Agreement with Columbia Power Corporation. The exchange net forecasts have also been revised due to changes in forecast Kootenay Canal Entitlement, and are reflected in Schedule A-9.

due to the impact of lower forecast water inflows in F2005 (reservoir management is undertaken on a multiple-year basis).

3.5 Operations, Maintenance, and Administration (OMA) Costs

On a consolidated basis, OMA costs are unchanged from the Revised Evidentiary Update. On a functional basis OMA costs have decreased as a result of the decrease in the allocation of Corporate costs (i.e. the decrease in OMA costs in the functions is offset by the decrease in the Corporate recovery).

Corporate costs are forecast to be lower than shown in the Application and the Revised Evidentiary Update due to a reduction in depreciation relating to IT expenditures as mentioned in Section 3.7. The reduction in Corporate costs from the Application is approximately $4 and $6 million for F2005 and F2006 respectively.

The components of the Corporate costs are shown on Schedule C6 and the allocation to the functions is shown on Schedules B-3 and B-4. The Corporate costs are allocated to the functions using the same methodology as described in Chapter 2, Section 7.2 of the Application.

3.6 Finance Charges

Table 2A-10 identifies finance charges during the test periods. The detailed components of the updated finance charge forecasts are shown in Schedule A-10.

Table 2A-10. Finance Charges, F2005 to F2006, Change from Prior Forecast

($ millions)	**F2005**	**F2006**
Finance Charges – June Financial Undertaking	$428	$458
Finance Charges – Revised Evidentiary Update	430	461
Decrease in finance charges	**$2**	**$3**

Forecast finance charges are slightly lower than forecast in the Revised Evidentiary Update. This is primarily due to a lower than forecast ending debt balance in F2004 and to an increase in cash flows in the test years. The debt balance as at March 31, 2004 was

approximately $100 million lower than forecast largely a result of lower capital spending as described in Section 3.7. While domestic energy costs in the test years have increased from the Revised Evidentiary Update, cash flows have increased largely a result of the lower dividend for F2004 and F2005. There is a time lag in cash flows as the dividend to the Province is paid in June following the year-end. A reduction in interest capitalized during construction, largely due to a refinement in the estimate of the average unfinished construction balances, partly offsets the favourable variance. The interest and foreign exchange rate assumptions used in the June Financial Undertaking are the same as used in the Evidentiary Update. These rates are shown in Table 2A-11 for convenience. These rates are the most current rates provided by the Provincial Government.

Table 2A-11. Interest Rate and Foreign Exchange Rate Forecast, F2005 to F2006

(Note 1)	**F2005 Forecast**	**F2006 Forecast**
Canadian Short-term Interest Rates	2.81%	4.03%
U.S. Short-term Interest Rates	1.74%	3.78%
Canadian Long-term Interest Rates	5.68%	6.26%
U.S. Long-term Interest Rates	5.70%	6.49%
USD/CAD FX Rate	0.7941	0.8006

Notes:
1. Provincial Government Forecast, January 22, 2004.

3.7 Capital Expenditures and Amortization Expenses

Actual capital expenditures in F2004 were lower than originally forecast in the Application and the Revised Evidentiary Update as shown in Table 2A-12. This together with the reduction in forecast capital expenditures for F2005 as shown in Exhibit B1-96, reduces amortization expenses from the Revised Evidentiary Update by $15 million and $18 million in F2005 and F2006 respectively. The portion of this reduction in amortization relating to lower capital spending in F2004 is estimated to be $13 million and $14 million for F2005 and F2006 respectively. Approximately half this decrease is due to lower Information Technology (IT) spending and the other half due to lower than forecast spending on Power

Smart programs during F2004. The lower spending in the other capital expenditure categories in F2004 have a minimal annual impact on depreciation due to the longer useful lives of these assets. The remainder of the decrease in amortization of $2 million and $4 million for F2005 and F2006 respectively is largely due to the lower IT capital expenditures forecast for F2005 compared to the Application.

The Actual and forecast capital expenditures for F2004 are shown below:

Table 2A-12. F2004 Capital Expenditures

($ millions)	**F2004 Actual**	**F2004 Forecast**	**Change**
Generation Thermal	$ 8.6	$38.8	$30.2
Generation Hydro	111.2	117.1	5.9
Transmission	176.7	176.0	(0.7)
Distribution	200.6	193.2	(7.4)
Computers	43.0	71.4	28.4
Vehicles	14.7	21.5	6.8
SSI and Aboriginal Negotiations	8.2	13.7	5.5
Land and Buildings	3.7	9.9	6.2
General	6.9	11.6	4.7
Power Smart	62.7	116.2	53.5
Total	**$636.3**	**$769.4**	**$133.1**

3.8 Taxes

There are no changes to forecast taxes.

3.9 Charges from the British Columbia Transmission Corporation

There are no changes to forecast BCTC charges.

3.10 Trade Income

There are no changes to the forecast of Trade Income.

SCHEDULE A-1 (Update of June 2004)

Consolidated Statement of Operations with Proposed Rate Increases
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
REVENUES				
Domestic				
Residential	$ 923	$ 960	$ 1,050	$ 1,073
Light industrial and commercial	893	912	988	1,009
Large industrial	516	525	568	567
Other energy sales	88	89	91	92
Miscellaneous	55	67	61	55
	2,475	2,553	2,758	2,796
Intersegment revenues	6	62	124	140
	2,481	2,615	2,882	2,936
EXPENSES				
Domestic energy costs	708	995	1,057	995
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	168	171	129
Maintenance expense	196	240	244	138
Administration expense	167	168	162	140
Depreciation and amortization	414	536	455	451
Taxes	145	146	145	147
	1,773	2,253	2,234	2,178
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	362	648	758
Finance charges	457	435	428	458
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	(73)	220	300
Restructuring Costs	37	8	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	(81)	220	300
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	**280**	**(60)**	**220**	**300**
TRADE NET INCOME	**138**	**158**	**89**	**91**
TOTAL NET INCOME	**$ 418**	**$ 98**	**$ 309**	**$ 391**
PAYMENT TO THE PROVINCE	$ 338	$ 73	$ 251	$ 309
ACTUAL/FORECAST RETURN ON EQUITY	15.47%	3.60%	10.17%	12.50%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.91%
BALANCE IN RSA	$ 21	$ -	$ -	$ -
RATE INCREASE	0.00%	0.00%	8.90%	0.00%
CUMULATIVE RATE INCREASE	0.00%	0.00%	8.90%	8.90%

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-2 (Update of June 2004)

Consolidated Balance Sheet
As at March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Capital Assets				
Capital assets in service	$ 14,940	$ 15,293	$ 15,843	$ 16,240
Less accumulated depreciation	5,816	5,964	6,273	6,573
	9,124	9,329	9,570	9,667
Unfinished construction	669	515	559	827
	9,793	9,844	10,129	10,494
Current Assets				
Temporary investments	4	47	4	4
Accounts receivable and accrued revenue	362	323	455	459
Materials and supplies	88	86	88	88
Prepaid expenses	86	108	86	66
Unrealized gains on mark-to-market transactions	10	104	-	-
	550	668	633	617
Other Assets and Deferred Charges				
Loan receivable	23	2	2	2
Sinking funds	1,037	981	984	844
Demand-Side Management programs	123	161	241	304
Deferred debt costs	385	150	84	52
	1,568	1,294	1,311	1,202
	$ 11,911	$ 11,806	$ 12,073	$ 12,313
Long term debt net of sinking funds	$ 6,853	$ 6,900	$ 6,942	$ 7,246
Sinking funds presented as assets	1,037	981	984	844
Long-Term Debt	7,890	7,881	7,926	8,090
Foreign Currency Contracts	2	63	65	60
Current Liabilities				
Accounts payable and accrued liabilities	689	672	658	585
Accrued interest	108	115	117	121
Accrued Payment to the Province	338	73	251	309
Unrealized losses on mark-to-market transactions	10	78	-	-
	1,145	938	1,026	1,015
Deferred Credits and Other Liabilities				
Provision for future removal and site restoration costs	174	202	-	-
Asset Retirement Obligation	-	-	19	20
Deferred revenue	258	276	293	313
Rate stabilization account	21	-	-	-
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	619	635	653
	1,265	1,290	1,131	1,161
Retained Earnings	1,609	1,634	1,925	1,987
	$ 11,911	$ 11,806	$ 12,073	$ 12,313
Debt to Equity Ratio	71.7:28.3	71.6:28.4	69.6:30.4	69.8:30.2

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-3 (Update of June 2004)

Consolidated Statement of Retained Earnings
For the Years ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Retained earnings at beginning of year	$ 1,529	$ 1,609	$ 1,634	$ 1,925
Net income	418	98	309	391
Payment to the Province	(338)	(73)	(251)	(309)
Asset Retirement Obligation Adjustment [1]	-	-	233	-
Special Dividend to the Province for BCTC [2]	-	-	-	(20)
Retained earnings at end of year	$ 1,609	$ 1,634	$ 1,925	$ 1,987

Notes:

1. This adjustment is explained in Section 3.7.3..
2. The Special Dividend to the Province for BCTC was paid in fiscal 2004. It is shown in fiscal 2006, because BCTC is consolidated with BC Hydro in fiscal 2004 and fiscal 2005.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-4 (Update of June 2004)

Consolidated Statement of Cash Flows
For the Years ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Operating Activities				
Net income	$ 418	$ 98	$ 309	$ 391
Adjustments for:				
Depreciation and amortization	417	539	459	455
Rate stabilization account	(66)	(21)	-	-
Other non-cash items	24	(4)	(9)	(18)
	793	612	759	828
Working capital changes	1	1	(121)	(53)
Cash provided by operating activities	794	613	638	775
Investing Activities				
Capital asset expenditures	(680)	(606)	(695)	(894)
Contributions in aid of construction	62	56	51	54
Demand side management programs	(45)	(63)	(105)	(94)
Future removal and site restoration costs	(12)	(15)	-	-
Net asset dismantling costs	-	-	(17)	(17)
Loan receivable	(8)	(1)	-	-
Proceeds from property and asset sales	1	10	4	79
Cash used for investing activities	(682)	(619)	(762)	(872)
Financing Activities				
Bonds, notes and debentures				
Issued	1,007	790	600	700
Retired	(1,019)	(450)	(598)	(607)
Revolving borrowings changes	147	(47)	118	90
Sinking funds	48	53	34	185
Deferred debt costs	3	7	-	-
Settlement of financial instruments	22	34	-	-
Cash provided by financing activities	208	387	154	368
Payment to the Province	(333)	(338)	(73)	(251)
Special Dividend to the Province for BCTC	-	-	-	(20)
Increase (decrease) in cash	(13)	43	(43)	-
Cash at beginning of year	17	4	47	4
Cash at end of year	$ 4	$ 47	$ 4	$ 4

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-5 (Update of June 2004)

Residential Revenues
For the Years Ended March 31
($ millions)

	A	B		C		D	
	F2003 Actual	**F2004 Actual**	**%**	**F2005 Forecast**	**%**	**F2006 Forecast**	**%**
Revenue							
Residential revenue	$923	$960	4%	$1,050	9%	$1,073	2%
Revenue variance	n/a	$37		$90		$23	
Variance							
Rate increase:		n/a		79		9	
Volume:							
Number of customers	n/a	15		15		17	
Usage per customer	n/a	28		(1)		1	
Power Smart savings	n/a	(6)		(3)		(4)	
Total Variance	n/a	$37		$90		$23	
Sales Volume (in GW·h)	15,024	15,646	4%	15,836	1%	16,063	1%

( ) represents a negative variance.

Residential revenues are expected to increase primarily due to the proposed rate increase and customer growth which is expected to be an average of 1.70% over the period from 2004 to 2006.

The usage variance in fiscal year 2004 is high due to the cooler weather in April and May affecting the heating load and the extreme warm weather in July and August affecting the cooling load. Fiscal 2003 was a warmer than normal year. Forecast 2005 and 2006 assumes normal weather.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-6 (Update of June 2004)

Light Industrial And Commercial Revenue
For the Years Ended March 31
($ millions)

	A	B		C		D	
	F2003 Actual	**F2004 Actual**	**%**	**F2005 Forecast**	**%**	**F2006 Forecast**	**%**
Revenue							
Light industrial & commercial	$893	$912	2%	$988	8%	$1,009	2%
Revenue variance	n/a	$19		$76		$21	
Variance							
Rate increase:		n/a		72		11	
Volume:							
GDP & Employment*	n/a	21		18		20	
Power Smart savings	n/a	(2)		(14)		(10)	
Total Variance	n/a	$19		$76		$21	
Sales Volume (in GW·h)	16,757	17,175	0%	17,232	0%	17,433	1%

* includes floor stock growth rates and end-use building intensities

( ) represents an unfavourable variance

Light industrial and commercial customers is comprised of small and large accounts. Small customers are defined as those with a monthly demand of less than 35 kilowatts and includes small retail operations, offices, schools and warehouses. Large accounts include retail, industrial and manufacturing customers whose monthly demand is 35 kilowatts or more.

The major change in revenues in fiscal 2005 and fiscal 2006 is due to the proposed rate increase and to increased volume from GDP, employment, floor stock building growth rates and end-use building intensities partially offset by expected Power Smart savings.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-7 (Update of June 2004)

Large Industrial Revenue
For the Years Ended March 31
($ millions)

	A	B		C		D	
	F2003 Actual	**F2004 Actual**	**%**	**F2005 Forecast**	**%**	**F2006 Forecast**	**%**
Revenue (in millions)							
Large industrial	$516	$525	2%	$568	8%	$567	0%
Revenue variance	n/a	$9		$43		$(1)	
Variance							
Rate increase:		n/a		42		4	
Volume:							
Usage per customer	n/a	14		9		1	
Power Smart savings	n/a	(5)		(8)		(6)	
Total Variance	n/a	$9		$43		$(1)	
Sales Volume (in GW·h)	15,179	15,505	2%	15,435	0%	15,297	-1%

( ) represents and unfavourable variance

Large industrial revenues are expected to increase largely due to the impact of the proposed rate increases. The increase in 2004 is due primarily to increased sales to metal mining customers, pulp and paper customers, wood manufacturing customers and pulp chemical customers. The metal mines, pulp and paper mills and wood manufacturers are commodity exporters whose sales have been positively impacted by the improvement in the Global economy. The pulp chemical sales are dependent on the pulp and paper sector and therefore have also been positively impacted.

Fiscal 2005 and fiscal 2006 revenues are expected to increase largely due to the impact of the proposed rate increases.

For fiscal 2005 and fiscal 2006, a major customer in the Pulp and Paper sector is expected to return to normal production levels after a strike during fiscal 2004. New coal mines coming on line are also expected to increase demand. The increase in consumption from the above is partially offset by the fact that commodity exporters are expected to remain under pressure from the continued strong Canadian dollar, foreign competition from Chile and Asia, as well as newer, more efficient mines and mills.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-8 (Update of June 2004)

Miscellaneous Revenues
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Plan**	**F2006 Plan**
Miscellaneous Revenues by Function				
Generation				
Ancillary services	$ 2	$ 2	$ 3	$ 5
Other	3	3	4	3
	5	5	7	8
Distribution				
Meter and transformer rents and power factor surcharges	6	6	5	5
Customer Care				
Terasen meter reading [1]	-	3	2	2
Other	2	4	2	2
	2	7	4	4
Transmission				
Short-term point to point wheeling revenue [2]	1	5	5	-
Aquila general wheeling revenue [2]	4	3	4	-
Transmission secondary revenue	4	5	4	5
	9	13	13	5
Field Services				
Fleet revenues	7	7	7	7
Corporate				
Corporate general rents	6	4	5	5
Net gains on property sales	2	9	2	2
Westech external revenues	5	1	3	3
	13	14	10	10
Powertech external revenues	13	15	15	16
	$ 55	$ 67	$ 61	$ 55

Notes:

1. The Terasen revenue was classified as an Operations, Maintenance, and Administration recovery in fiscal 2003.
2. The revenues for fiscal 2006 will be part of BCTC's revenues. Prior to fiscal 2006, BCTC is consolidated with BC Hydro due to their financial and operational dependence. BCTC will apply for their own tariff rates in F2006 and will therefore no longer be operationally and financially dependent on BC Hydro.

SCHEDULE A-9 (Update of June 2004)

Domestic Cost Of Energy
For the Years Ended March 31
($ millions)

	A	B	C	D	
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**	**Reference**
Domestic cost of energy :					
Water rentals	$258	$246	$253	$279	D1-2
Independent Power Producers and long-term purchase commitments	290	372	385	416	C2
Market electricity purchases	54	270	343	222	D1-2
Net Purchases from Powerex *(Note 1)*	50	30			D1-2
Natural gas for thermal generation *(Note 2)*	28	33	28	28	D1-2
Domestic cost of energy - Non-integrated Areas	14	14	15	15	C4
Domestic transmission	5	16	15	15	D1-2
Gas transportation	5	10	13	13	C2
Cost of market *(Note 3)*	1	1	1		C3
Other	3	3	4	7	D1-2
Total Domestic cost of energy	$708	$995	$1,057	$995	

	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Domestic energy:				
GW·h's				
Water rentals	47,665	44,540	44,737	45,932
Independent Power Producers and long-term purchase commitments	4,950	6,133	6,379	7,019
Market electricity purchases	896	5,349	6,153	4,406
Net Purchases from Powerex *(Note 1)*	1,113			
Thermal generation	251	296	207	214
Non-integrated Areas	96	99	103	105
Exchange net	(1,605)	(1,218)	(624)	54
	53,366	55,199	56,955	57,730
Less: Line loss and system use	(4,689)	(5,000)	(5,284)	(5,621)
Net sales to Powerex		(48)	(1,454)	(1,578)
Domestic sales volumes	48,677	50,151	50,217	50,531
$/MW·h				
Water rentals	$ 5.4	$ 5.5	$ 5.7	$ 6.1
Independent Power Producers and long-term purchase commitments	58.6	60.7	60.4	59.3
Market electricity purchases	60.3	50.5	55.7	50.4
Net Purchases from Powerex	44.9			
Natural gas for thermal generation	111.6	111.5	135.3	130.8
Domestic cost of energy - Non-integrated Areas	145.8	141.4	145.6	142.9
Total weighted average cost *(Note 4)*	$ 14.5	$ 19.8	$ 21.0	$ 19.7

Notes:

1. In F2004, Powerex drew down the trade account by 48 GWh, which is made up of 1,693 GWh out of the trade account and 1,645 GWh into the trade account. The value of the energy going into the trade account is more expensive than the current average cost of the trade account. This difference results in a net cost to domestic cost of energy of $30 million. (i.e., The revenues BC Hydro would record from Powerex when the trade account is drawn down is less than the cost BC Hydro records from Powerex when the trade account is increased.) This does not have an impact on the Heritage Contract.
2. This includes fixed transportation costs of approximately $10 million related to the Bypass Transportation Agreement between Terasen and BC Hydro.
3. Domestic cost of energy transmission which includes congestion management cost.
4. Calculated as total cost divided by sales volumes.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-10 (Update of June 2004)

Finance Charges
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Interest on debt securities				
Bonds, notes and debentures	$ 536	$ 507	$ 483	$ 506
Revolving borrowings	5	9	12	17
Amortization of deferred debt costs and other expenses	26	28	32	33
	567	544	527	556
Less:				
Sinking fund income	(60)	(58)	(53)	(48)
Other income *(Note 1)*	(26)	(34)	(26)	(15)
Finance charges capitalized to unfinished construction	(24)	(17)	(20)	(35)
	(110)	(109)	(99)	(98)
Total	$ 457	$ 435	$ 428	$ 458
Average interest rates				
Long-term debt				
Canadian	8.3%	7.7%	7.4%	7.3%
Foreign	4.5%	4.4%	4.7%	5.6%
Short-term debt	2.4%	2.9%	2.8%	4.0%
Average exchange rate in U.S. dollars	0.65	0.74	0.79	0.80

Note:
1. Other income largely relates to income on interest rate and cross currency swaps.

Average interest rates relate to the weighted average interest rate and represents the effective rate of interest on fixed-rate bonds and notes and the current interest rate in effect at March 31 for floating-rate bonds and notes, all before considering the effect of derivative financial instrument used to manage interest rate risk.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-11 (Update of June 2004)

Consolidated Capital Asset
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
CAPITAL ASSETS IN SERVICE				
Balance at beginning of year	14,608	14,940	15,293	15,843
Assets in Service	461	622	642	584
ARO Implementation asset			14	
Retirements	(129)	(191)	(106)	(187)
Balance Sheet Reclassifications (Note 1)		(78)		
Balance at end of year	14,940	15,293	15,843	16,240
ACCUMULATED DEPRECIATION				
Balance at beginning of year	5,557	5,816	5,964	6,273
Depreciation	382	405	452	441
ARO implementation Accum dep			7	
Salvage Value Trfr from FRSR			(46)	
Retirements	(123)	(184)	(104)	(141)
Balance Sheet Reclassification (Note 1)		(73)		
Balance at end of year	5,816	5,964	6,273	6,573
NET BOOK VALUE	9,124	9,329	9,570	9,667
UNFINISHED CONSTRUCTION				
Balance at beginning of year	459	669	515	558
Additions	696	574	694	895
Amortization	(8)	(8)	(8)	(9)
Write-offs/Provision (Note 2)	(17)	(98)		
Inter LoB transfers				
F06 Trfrs to BCTC				(33)
Transfer to assets in service	(461)	(622)	(642)	(584)
Balance at end of year	669	515	559	827
	$ 9,793	$ 9,844	$ 10,129	$ 10,494

Note 1: Primarily relates to assets transferred to BCTC. Accumulated Depreciation on assets transferred to BCTC was netted against the original cost of the assets in BCTC's records. As BCTC is consolidated with BC Hydro for F2005, this reclassification is needed to correctly show the consolidated Capital Asset in Service and Accumulated Depreciation balances.

Note 2: F2004 includes the provision relating to VIGP/GSX.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-12 (Update of June 2004)

Composition of Long-term Debt
As at March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Bonds, notes and debentures				
Canadian	$ 4,888	$ 4,938	$ 5,150	$ 5,437
Foreign	2,671	2,659	2,374	2,161
	7,559	7,597	7,524	7,598
Less:				
Sinking funds	1,037	981	984	844
Net bonds, notes and debentures	6,522	6,616	6,540	6,754
Revolving borrowings	331	284	402	492
Long-term debt net of sinking funds	6,853	6,900	6,942	7,246
Sinking funds presented as assets	1,037	981	984	844
Long-term debt	$ 7,890	$ 7,881	$ 7,926	$ 8,090
Foreign currency contracts (Dr)	(13)	-	-	-
Foreign currency contracts Cr	15	63	65	60

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-12-1 (Update for June 2004)

Net Long-term Debt
For the Years Ended March 31
($ millions)

Long-term debt consists of bond, notes and debentures and revolving borrowings obtained under a borrowing agreement with the Province. Long-term debt is presented net of sinking funds.

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Balance at Beginning of Year	$ 6,906	$ 6,853	$ 6,900	$ 6,942
Add (less):				
New financing	1,007	790	600	700
Retirements	(1,019)	(450)	(598)	(607)
Revolving borrowings	147	(57)	118	90
	135	283	120	183
Exchange and other adjustments	(179)	(229)	(60)	(15)
Sinking fund (increase) decrease	(9)	(7)	(18)	136
Balance at End of Year	$ 6,853	$ 6,900	$ 6,942	$ 7,246

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-13 (Update for June 2004)

Contributions in Aid
For the Years ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Contributions in Aid:				
Opening balance	$ 935	$ 977	$ 1,003	$ 1,026
Current year additions	61	56	51	54
Balance sheet reclassifications [1]	-	(12)	-	-
Less retirements	(19)	(18)	(28)	(26)
Balance at end of year	977	1,003	1,026	1,054
Accumulated Amortization:				
Opening balance	354	368	384	391
Current year amortization	33	35	35	36
Less retirements	(19)	(19)	(28)	(26)
Balance at end of year	368	384	391	401
NET CONTRIBUTIONS IN AID	$ 609	$ 619	$ 635	$ 653

Certain customers contribute amounts towards the cost of capital assets required for extension of services. These amounts are amortized over the expected useful life of the related assets.

Note:
1. Amounts transferred to Capital Assets from contributions in aid to correct classification error.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-14 (Update for June 2004)

Contributions Arising from the Columbia River Treaty
For the Years ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Original contribution	$ 479	$ 479	$ 479	$ 479
Accumulated depreciation:				
Beginning of year	(267)	(276)	(286)	(295)
Amortization	(9)	(10)	(9)	(9)
	(276)	(286)	(295)	(304)
BALANCE AT END OF YEAR	$ 203	$ 193	$ 184	$ 175

Contributions Arising from the Columbia River Treaty relate to three dams built by BC Hydro in the mid-1960's to regulate the flow of the Columbia River. The proceeds received were contributed to BC Hydro to assist in financing the dams' construction. These proceeds were deferred and are amortized to income over the period ending in fiscal 2025, the minimum term of the treaty.

SCHEDULE A-15 (Update of June 2004)

Return on Equity
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Actual/forecast return on equity	15.47%	3.60%	10.17%	12.50%
Allowed return on equity [1]	15.47%	14.33%	13.91%	13.91%
Numerator				
Consolidated net income after rate stabilization account transfer	$ 418	$ 98	$ 309	$ 391
Denominator				
Retained earnings - end of year	$ 1,609	$ 1,634	$ 1,925	$ 1,987
Deferred credits - end of year	1,091	1,088	1,112	1,141
Equity - end of year	$ 2,700	$ 2,722	$ 3,037	$ 3,128

Note:

1. Return on equity is calculated in accordance with HSD #2 - see section 3.1.

Definition of Return on Equity

Return on equity = Consolidated Net Income / Ending Equity

Where Equity = Retained earnings + Deferred credits

Where Deferred credits = Deferred revenue + Contributions arising from the Columbia River Treaty and Contributions in aid of construction + RSA balance

	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Deferred Credits				
Deferred revenue	$ 258	$ 276	$ 293	$ 313
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	619	635	653
Rate stabilization account	21	-	-	-
	$ 1,091	$ 1,088	$ 1,112	$ 1,141

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-16 (Update of June 2004)

Debt To Equity Ratio
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	**F2004 Actual**	**F2005 Forecast**	**F2006 Forecast**
Debt to equity	72:28	72:28	70:30	70:30
Debt				
Long term debt net of sinking funds	$6,853	$6,900	$6,942	$7,246
Temporary investments	(4)	(47)	(4)	(4)
	$6,849	$6,853	$6,938	$7,242
Equity				
Deferred credits	$1,091	$1,088	$1,112	$1,141
Retained earnings	1,609	1,634	1,925	1,987
	$2,700	$2,722	$3,037	$3,128

Definition of Debt to Equity

$$\frac{\text{Debt}}{\text{Debt+Equity}} \times 100 : \frac{\text{Equity}}{\text{Debt+Equity}} \times 100$$

Where Debt = Bonds + Notes + Debentures + Revolving borrowings - Sinking funds - Term debentures - Temporary investments

Where Equity = Retained earnings + Deferred credits

Where Deferred credits = Deferred revenue + Contributions arising from the Columbia River Treaty + Contributions in Aid of Construction + RSA balance

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B (Update of June 2004)

Functionalized Costs
F2003

	($ millions)	Corporate	Energy Supply less Heritage Payment Obligation [1]	Generation (Heritage Contract) [2]	Transmission [6]	Electricity Distribution &NIA [7]	Customer Care [1]	Service Orgs and Subsidiaries	Consolidated
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		294.6	399.1	0.8	14.1			708.6
	OMA Expenses								-
	Operations, maintenance, and administration (net)	68.4	12.5	119.5	130.2	86.7	89.8	(1.2)	505.9
	Corporate Allocations	(84.6)	7.6	27.9	28.0	15.3	5.0	0.8	-
B2	Adjusted OMA including Corporate Allocations	(16.2)	20.1	147.4	158.2	102.0	94.8	(0.4)	505.9
B4	Depreciation	50.3	22.4	110.7	129.9	87.6		12.9	413.8
B3	Taxes	7.3		29.0	89.4	18.3		1.0	145.0
B5	Finance charges	-	5.0	213.0	135.0	104.0		-	457.0
B6	Allowed net income (return on equity)		4.0	195.0	123.0	96.0		-	418.0
C3	Other [3]			37.0		52.0			89.0
A-1	Restructuring costs	36.5							36.5
A-8	Miscellaneous external revenues	(12.9)		(165.2)	(96.7)	(6.7)	(2.1)	(19.9)	(303.5)
	Cost of Service by Function	65.0	346.1	966.0	539.6	467.3	92.7	(6.4)	2,470.3
A-8	Transmission 3rd party wheeling revenues [4]								(0.8)
A-1	Intersegment revenues [5]								(6.0)
	Total Revenue Requirement								2,463.5
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	

Notes:

1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.
2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2.
3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Generation and to Substation Distribution Asset Management charges from BC Hydro Transmission to BC Hydro Distribution.
4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service.
5. See Chapter 2 Section 3.3 for details.
6. Domestic cost of energy for Transmission is from cost of market for transmission (see Schedule C3).
7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4).

SCHEDULE B-1 (Update of June 2004)

Functionalized Costs
F2004

	($ millions)	Corporate	Energy Supply less Heritage Payment Obligation [1]	Generation (Heritage Contract) [2]	Transmission [6]	Electricity Distribution &NIA [7]	Customer Care [1]	Service Orgs and Subsidiaries	Consolidated
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		382.1	597.7	1.0	14.2			995.0
	OMA Expenses								-
	Operations, maintenance, and administration (net)	46.5	25.3	148.4	159.4	109.2	111.6	(15.8)	584.6
	Corporate Allocations	(117.5)	9.2	35.7	22.7	18.8	6.1	25.0	-
B2	Adjusted OMA including Corporate Allocations	(71.0)	34.5	184.1	182.1	128.0	117.7	9.2	584.6
B4	Depreciation	56.8	21.6	216.3	145.5	83.7		12.3	536.2
B3	Taxes	9.9		28.2	88.4	18.9		1.0	146.4
B5	Finance charges	10.1	4.0	197.0	127.8	96.1		-	435.0
B6	Allowed net income (return on equity)		4.0	183.4	119.1	89.5		-	396.0
C3	Other [3]			43.3		52.0			95.3
A-1	Restructuring costs								-
A-8	Miscellaneous external revenues	(14.5)		(181.4)	(103.7)	(6.4)	(6.6)	(21.6)	(334.2)
	Cost of Service by Function	(8.7)	446.2	1,268.6	560.2	476.0	111.1	0.9	2,854.3
A-8	Transmission 3rd party wheeling revenues [4]								(4.9)
A-1	Intersegment revenues [5]								(62.0)
	Total Revenue Requirement								2,787.4
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	

Notes:

1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.
2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2.
3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Generation and to Substation Distribution Asset Management charges from BC Hydro Transmission to BC Hydro Distribution.
4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service.
5. See Chapter 2 Section 3.3 for details.
6. Domestic cost of energy for Transmission is from cost of market for transmission (see Schedule C3).
7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4).

SCHEDULE B-2 (Update of June 2004)

Functionalized Costs
F2005

	($ millions)	Corporate	Energy Supply less Heritage Payment Obligation[1]	Generation (Heritage Contract)[2]	Transmission[7]	Electricity Distribution &NIA[8]	Customer Care[1]	Service Orgs and Subsidiaries	Consolidated
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		397.8	643.2	1.0	15.0			1,057.0
	OMA Expenses								-
	Operations, maintenance, and administration (net)	70.4	22.6	125.4	167.5	107.4	101.5	(17.7)	577.1
	Corporate Allocations	(126.6)	12.3	41.5	14.1	25.0	8.2	25.5	-
B2	Adjusted OMA including Corporate Allocations	(56.2)	34.9	166.9	181.6	132.4	109.7	7.8	577.1
B4	Depreciation	49.8	23.1	129.0	150.6	88.0		14.2	454.7
B3	Taxes	7.4		28.6	89.5	18.8		1.1	145.4
B5	Finance charges	9.5	4.2	190.5	125.2	98.6		-	428.0
B6	Allowed net income (return on equity)		4.4	193.3	127.2	100.1		-	425.0
C3	Other[3]			43.3		67.9			111.2
A-1	Restructuring costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.5)		(115.2)	(119.2)	(4.5)	(4.2)	(21.6)	(275.2)
	Cost of Service by Function	-	464.4	1,279.6	555.9	516.3	105.5	1.5	2,923.2
A-8	Transmission 3rd party wheeling revenues[4]								(5.5)
A-1	Intersegment revenues[5]								(124.0)
	Total Revenue Requirement[6]								2,793.7
	Schedule to cross reference	C6	C2	C1	C3	C4	C5	C7	

Notes:

1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.
2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2.
3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Generation and to Substation Distribution Asset Management charges from BC Hydro Transmission to BC Hydro Distribution.
4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service
5. See Chapter 2 Section 3.3 for details.
6. Small differences from Chapter 1 Table 3 relate to rounding differences.
7. Domestic cost of energy for Transmission is from cost of market for transmission (see schedule C3)
8. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4)

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B-3 (Update of June 2004)

Functionalized Costs
F2006

	($ millions)	Corporate	Energy Supply less Heritage Payment Obligation[1]	Generation (Heritage Contract)[2]	Transmission	Electricity Distribution &NIA[7]	Customer Care[1]	Service Orgs and Subsidiaries	Consolidated
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		428.7	551.6		15.0			995.3
	OMA Expenses								-
	Operations, maintenance, and administration (net)	69.8	20.9	126.0	3.5	107.6	97.3	(18.2)	406.9
	Corporate Allocations	(126.0)	11.9	41.9	14.3	24.4	8.0	25.5	-
B2	Adjusted OMA including Corporate Allocations	(56.2)	32.8	167.9	17.8	132.0	105.3	7.3	406.9
B4	Depreciation	50.7	28.1	124.9	141.2	91.2		15.0	451.1
B3	Taxes	7.5		29.0	90.5	19.1		1.0	147.1
B5	Finance charges	8.1	4.7	201.0	132.4	111.8		-	458.0
B6	Allowed net income (return on equity)		4.5	194.8	128.3	108.4		-	436.0
C3	Other[3]			43.3		68.9			112.2
A-1	Restructuring Costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.1)		(118.8)	(117.9)	(4.5)	(4.2)	(22.5)	(278.0)
	Cost of Service by Function	-	498.8	1,193.7	392.3	541.9	101.1	0.8	2,728.6
BCTC	Asset Management Fee to BCTC[4]								116.7
BCTC	WTS Charges from BCTC[4]								61.0
A-1	Intersegment revenues[5]								(140.0)
	Total Revenue Requirement[6]								2,766.3
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	

Notes:
1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.
2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2.
3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Generation and to Substation Distribution Asset Management charges from BC Hydro Transmission to BC Hydro Distribution.
4. Relates to charges from BCTC
5. See Chapter 2 Section 3.3 for details.
6. Small differences from Chapter 1 Table 3 relate to rounding differences.
7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4)

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B1 (Updated June 2004)

Domestic Cost of Energy

($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
1	Domestic Cost of Energy [1]	A-9	708	995	1,057	995
	Domestic Cost of Energy					
2	Domestic Cost of Energy-Generation	D1-2	399.1	597.7	643.2	551.6
3	Domestic Cost of Energy-Energy Supply less Heritage Payment Obligation	C2	294.6	382.1	397.8	428.7
4	Domestic Cost of Energy-Transmission	C3	0.8	1.0	1.0	-
5	Domestic Cost of Energy-Non-integrated areas	C4	14.1	14.2	15.0	15.0
6	Total Domestic Cost of Energy		708.6	995.0	1,057.0	995.3

7 Notes:
8 1. The figures from Schedule A-9 have been rounded to the nearest $ million.

10 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B2 (Update of June 2004)

Operations, Maintenance, and Administration

($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operations, Maintenance, and Administration					
1	Operations		143	168	171	129
2	Maintenance		196	240	244	138
3	Administration		167	168	162	140
4			506	576	577	407
5	Restructuring costs		37	8	0	0
6		A-1	543	584	577	407
	Operations, Maintenance, and Administration					
	Domestic Operations					
7	Generation (Heritage Contract)	D1-1	147.4	184.1	166.9	167.9
8	Energy Supply Cost less Heritage Payment Obligation	C2	20.1	34.5	34.9	32.8
9	Transmission (Note 1)	D4	158.2	182.1	181.6	17.8
10	Electricity Distribution and Non-Integrated Areas	D5	102.0	128.0	132.4	132.0
11	Customer Care	D6	94.8	117.7	109.7	105.3
12	Corporate	D7	(16.2)	(71.0)	(56.2)	(56.2)
13	Engineering Services	D8	(3.9)	(0.3)	(0.6)	(0.6)
14	Field Services	D9	(3.8)	(4.8)	(7.6)	(8.6)
15	MMBU	D10	(3.0)	(1.2)	0.6	0.6
16	Powertech	C7	10.3	13.2	13.1	13.6
17	Total OMA for Domestic Operations		505.9	582.3	574.8	404.6
18	Allocation of Corporate costs to Powerex		-	2.3	2.3	2.3
19			505.9	584.6	577.1	406.9

20 Note 1: F2004 includes $8.3 million of restructuring costs.

21 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B3 (Update of June 2004)

Taxes

($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Taxes 1					
1	Grants		$ 42	$ 42	$ 44	$ 45
2	School Taxes		100	99	101	102
3	Other		3	5		
4	Total	A-1	$145	$146	$145	$147
	Taxes by Functional Area					
5	Generation (Heritage Contract)	C1	29.0	28.2	28.6	29.0
6	Transmission	C3	89.4	88.4	89.5	90.5
7	Electricity Distribution and Non-Integrated Areas	C4	18.3	18.9	18.8	19.1
8	Corporate	C6	7.3	9.9	7.4	7.5
9	Field Services	C7	0.2	0.2	0.2	0.1
10	MMBU	C7	0.8	0.8	0.9	0.9
11	Total		145.0	146.4	145.4	147.1

12 Note 1: The figures on Schedule A-1 have been rounded to the nearest $ million.

SCHEDULE B4 (Update of June 2004)

Depreciation and Amortization

($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Depreciation and Amortization 1					
1	Depreciation of capital assets in service		$ 379	$ 402	$ 447	$ 437
2	Amortization of contributions		(42)	(45)	(44)	(45)
3	Amortization of studies and abandoned projects		11	8	8	9
4	Amortization of DSM		25	25	26	31
5	Future removal and site restoration costs		27	35	N/A	N/A
6	Asset Dismantling and Site Restoration costs				18	19
7	Capital asset write-offs		14	13		
8	Valuation provision 2			98		
9	Total	A-1	$ 414	$ 536	$ 455	$ 451
	Depreciation and Amortization by Functional Area					
10	Generation 2	C1	110.7	216.3	129.0	124.9
11	Energy Supply Cost less Heritage Payment Obligation	C2	22.4	21.6	23.1	28.1
12	Transmission	C3	129.9	145.5	150.6	141.2
13	Electricity Distribution and Non-Integrated Areas	C4	87.6	83.7	88.0	91.2
14	Corporate	C6	50.3	56.8	49.9	50.7
15	Engineering	C7	0.8	0.3	0.3	0.3
16	Field Services	C7	10.9	11.0	12.5	13.3
17	Powertech	C7	0.6	0.5	0.7	0.7
18	MMBU	C7	0.6	0.5	0.7	0.7
19	Total		413.8	536.2	454.8	451.1

20 Notes:

21 1. The figures on Schedule A-1 have been rounded to the nearest $ million.

22 2. Relates to valuation provision to the VIGP/GSX projects. The $98 million valuation provision in

23 F2004 is shown as part of the Generation function.

24 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B5 (Update of June 2004)

Finance Charges
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Finance Charges1					
	Interest on Debt Securities					
1	- bonds, notes and debentures		$536	$507	$483	$506
2	- revolving borrowings		5	9	12	17
3	Amortization of deferred debt costs and other expenses		26	28	32	33
4			$567	$544	$527	$556
	Less:					
5	Sinking fund income		(60)	(58)	(53)	(48)
6	Other income		(26)	(34)	(26)	(15)
7	Finance charges capitalized to unfinished construction		(24)	(17)	(20)	(35)
8			(110)	(109)	(99)	(98)
9	Total	A-1	457.0	435.0	428.0	458.0
	Allocation of Finance Charges by Functional Area					
10	Generation (Heritage Contract)	C1	213.0	197.0	190.5	201.0
11	Energy Supply Cost less Heritage Payment Obligation	C2	5.0	4.0	4.2	4.7
12	Transmission	C3	135.0	127.8	125.2	132.4
13	Electricity Distribution and Non-Integrated Areas	C4	104.0	96.1	98.6	111.8
14	Corporate	C6	-	10.1	9.5	8.1
15	Total		457.0	435.0	428.0	458.0

16 Notes:
17 1. The figures from Schedule A-1 have been rounded to the nearest $ million.

18 Total finance charges less the portion attributable to Corporate are allocated based on the percentages shown in Schedule B7.

19 The Corporate portion relates to the deemed interest charges on assets held in BCH Service Asset Corporation (see section 6.2.2, chapter 2 of th

20 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B6 (Update of June 2004)

Allowed Net Income (Return on Equity)
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Allowed Net Income (Return on Equity)					
1	Allowed ROE%	Chapter 10	15.47%	14.33%	13.91%	13.91%
2	Ending Equity Balance	A-15	$2,700	$ 2,722	$ 3,037	$ 3,128
3	Allowed Net Income		$ 418	$ 396	$ 425	$ 436
	Allocation of Allowed Net Income (Return on Equity)					
4	Generation (Heritage Contract)	C1	195.0	183.4	193.3	194.8
5	Energy Supply Cost less Heritage Payment Obligation	C2	4.0	4.0	4.4	4.5
6	Transmission	C3	123.0	119.1	127.2	128.3
7	Electricity Distribution and Non-Integrated Areas	C4	96.0	89.5	100.1	108.4
8	Total		418.0	396.0	425.0	436.0

9 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE B7 (Update of June 2004)

Allocation of Finance Charges

($ millions)

	F2003 Actual	F2004 Actual	F2005 Plan	F2006 Plan
Net Book Value of Capital Assets	$ 2,526	$ 2,588	$ 2,637	$ 2,632
10% of Demand Side Management [1]	12	16	23	28
	2,538	2,604	2,660	2,660
CIA	(81)	(85)	(89)	(94)
Transmission Rate Base [2]	$ 2,457	$ 2,519	$ 2,571	$ 2,566
Transmission Average Balance		2,488	2,545	2,569
Net Book Value of Capital Assets	3,842	3,854	3,908	3,911
CIA	(14)	(10)	(10)	(9)
Generation Rate Base	$ 3,828	$ 3,844	$ 3,898	$ 3,902
Generation Average Balance		3,836	3,871	3,900
Net Book Value of Capital Assets	2,304	2,373	2,509	2,615
90% of Demand Side Management	110	145	217	273
	2,414	2,518	2,726	2,888
CIA	(510)	(526)	(538)	(552)
Distribution Rate Base	$ 1,904	$ 1,992	$ 2,188	$ 2,336
Distribution Average Balance		1,948	2,090	2,262
BC Hydro (T,G&D) Average Balance		$ 8,272	$ 8,506	$ 8,731
Portion of Rate Base:				
Transmission	29.49%	30.08%	29.92%	29.42%
Generation (Heritage Contract)	46.60%	46.37%	45.51%	44.67%
Distribution total	23.91%	23.55%	24.57%	25.91%
-Energy Management [3]	0.96%	0.94%	1.00%	1.04%
-Electricity Distribution and Non-Integrated Areas	22.95%	22.61%	23.57%	24.87%
	100.00%	100.00%	100.00%	100.00%

Notes:

1. 10% of DSM costs are allocated to the transmission rate base and 90% of DSM are allocated to the distribution rate base.
2. Includes consolidation of BCTC for F2004 and F2005.
3. The total distribution share is further separated into the shares for the Energy Management (4%) and Electricity Distribution and NIA functions (96%).

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE C (Update of June 2004)

Functional Revenue Requirements Summary
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
1	Cost of Service - Generation (Heritage Contract)	C1	966.0	######	1,279.6	1,193.7
2	Cost of Service - Energy Supply Cost less Heritage Payment Obligation	C2	346.1	446.2	464.4	498.8
3	Cost of Service - Transmission BC Hydro portion	C3	539.6	560.2	555.9	392.3
4	Cost of Service - Electricity Distribution and Non-Integrated Areas	C4	467.3	476.0	516.3	541.9
5	Cost of Service - Customer Care1	C5	92.7	111.1	105.5	101.1
6	Cost of Service - Corporate	C6	65.0	(8.7)	-	-
7	Cost of Service - Service Organizations and Subsidiaries	C7	(6.4)	0.9	1.5	0.8
8			######	######	2,923.2	2,728.6
9	Asset Management Fee from BCTC	BCTC	-	-	-	116.7
10	Wholesale Transmission Service Charges from BCTC	BCTC	-	-	-	61.0
11			######	######	2,923.2	2,906.3
12	Less: Transmission Point-to-Point Wheeling in Miscellaneous Revenues1	A-8	0.8	4.9	5.5	-
13	Inter-Segment Revenues	A-1	6.0	62.0	124.0	140.0
14			6.8	66.9	129.5	140.0
15	Total Cost of Service		######	######	2,793.7	2,766.3
	Contributions by Customer Segment					
16	Residential		923	960	1,050	1,073
17	Light Industrial and Commercial		893	912	988	1,009
18	Large Industrial		516	525	568	567
19	Other Energy Sales		88	89	91	92
20	Transfer from RSA		66	21		
21			2,486	2,507	2,697	2,741
22	Less: Other Utilities revenues included in Other Energy Sales		22	18	19	20
23			2,464	2,489	2,678	2,721
24	Net Income Shortfall		-	298.4	115.7	45.3
25			(0.5)	-	-	-
26			######	######	2,793.7	2,766.3

27 Notes:
28 1. These relate to Wheeling tariff revenues and are therefore not deducted
29 in calculating the Transmission Cost of Service. They are deducted in
30 calculating BC Hydro's total cost of service.

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE C1 (Update of June 2004)

Cost of Service - Generation
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Cost of Service - Generation (Heritage Contract)					
1	Generation OMA	D1-1	$ 147.4	$ 184.1	$ 166.9	$ 167.9
2	Domestic Cost of Energy-Generation	D1-2	399.1	597.7	643.2	551.6
3	GRTA charges from Transmission	C3	37.0	43.3	43.3	43.3
4	Taxes	B3	29.0	28.2	28.6	29.0
5	Depreciation and Amortization	B4	110.7	216.3	129.0	124.9
6	Finance Charges	B5	213.0	197.0	190.5	201.0
7	Allowed return on equity		195.0	183.4	193.3	194.8
8	Total Cost		1,131.2	1,450.0	1,394.8	1,312.5
9	Less: Trade Income	A-1	138.0	158.0	89.0	91.0
10	Other Utilities		21.9	18.0	18.9	19.4
11	Other miscellaneous Non-tariff revenues	A-8	5.3	5.4	7.3	8.4
12			165.2	181.4	115.2	118.8
13	Total Cost of Service - Generation[1]		$ 966.0	$1,268.6	$1,279.6	$1,193.7

14 Note:
15 1. This is not the same as the Heritage Payment Obligation. The reconciliation is shown in
16 Schedules D1-2 and D1-3.

SCHEDULE C2 (Update of June 2004)

Cost of Service - Energy Supply Cost less Heritage Payment Obligation
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Cost of Service - Energy Supply Cost less Heritage Payment Obligation					
1	Depreciation and Amortization[1]	B4	22.4	21.6	23.1	28.1
2	Finance Charges[1]	B5	5.0	4.0	4.2	4.7
3	Allowed ROE[1]	B6	4.0	4.0	4.4	4.5
4			31.4	29.6	31.7	37.3
5	Power Smart OMA	D3	12.8	20.2	22.1	21.8
6			44.2	49.8	53.8	59.1
7	IPP Cost of Energy and long-term purchase commitments[2]	A-9	289.4	372.2	384.8	415.7
8	Gas transportation & domestic transmission	A-9	5.2	9.9	13.0	13.0
9	Domestic cost of energy-Energy Supply Cost		294.6	382.1	397.8	428.7
10	Energy Management OMA	D2	7.3	14.3	12.8	11.0
11	Cost of Service-Energy Supply Cost less Heritage Payment Obligation		346.1	446.2	464.4	498.8

12 Notes:
13 1. 90% of DSM amortization is shown as part of Energy Supply Cost and 10% is shown as part of Transmission
14 (Schedule C3).
15 2. Includes purchase commitments entered into before F2001 and agreements from F2001. See Chapter 4 Table 1.

16 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE C3 (Update of June 2004)

Cost of Service - Transmission
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast BC Hydro	F2006 Forecast BCTC
1	Operating, Maintenance & Administration (Note 1)	D4	158.2	182.1	181.6	17.8	166.1
2	Cost of Market (Note 2)	B1	0.8	1.0	1.0	-	5.8
	Asset Related Expense						
3	Finance Charge	B5	135.0	127.8	125.2	132.4	1.7
4	Depreciation & Amortization (Note 3)	B4	129.9	145.5	150.6	141.2	16.7
5	Grants & Taxes	B3	89.4	88.4	89.5	90.5	0.3
6	Allowed Return	B6	123.0	119.1	127.2	128.3	3.9
7	**Total Cost**		**636.3**	**663.9**	**675.1**	**510.2**	**194.5**
	Less Non-WTS Revenues and Recoveries						
8	Generation Related Transmission Assets	C1	(37.0)	(43.3)	(43.3)	(43.3)	
9	Substation Distribution Asset Management	C4	(52.0)	(52.0)	(67.9)	(68.9)	
10	Aquila General Wheeling Agreement	A8	(3.8)	(3.7)	(3.8)		(3.8)
11	Secondary Revenues	A8	(3.8)	(4.7)	(4.2)	(5.7)	
12	Other Recoveries		(0.1)	-			
13	**Total Non-WTS Revenues and Recoveries**		**(96.7)**	**(103.7)**	**(119.2)**	**(117.9)**	**(3.8)**
14	**Total Transmission Revenue Requirement**		**539.6**	**560.2**	**555.9**	**392.3**	**190.7**

15 Notes:
16 (1) F2004 includes $8.3 million in restructuring costs.
17 (2) F2003 through F2005 reflects Congestion Mgmt cost only, F206 reflects Ancillary Services cost plus Congestion Mgmt.
18 (3) Includes 10% of amortization relating to DSM. Remaining 90% is shown in Energy Supply Cost - Cost of Service (Schedule C2).

19 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE C4 (Update of June 2004)

Cost of Service - Electricity Distribution and Non-Integrated Areas
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Cost of Service - Electricity Distribution and Non-integrated Areas					
1	Domestic Cost of Energy - Non-Integrated Areas	A9	14.1	14.2	15.0	15.0
2	Electricity Distribution and Non-Integrated Areas OMA	D5	102.0	128.0	132.4	132.0
3	Taxes	B3	18.3	18.9	18.8	19.1
4	Depreciation and Amortization	B4	87.6	83.7	88.0	91.2
5	Finance Charges	B5	104.0	96.1	98.6	111.8
6	Allowed Net Income	B6	96.0	89.5	100.1	108.4
7	Sub-Total		422.0	430.4	452.9	477.5
8	Distribution Substations (from Transmission)	C3	52.0	52.0	67.9	68.9
9	Cost of Service - Electricity Distribution and Non-Integrated Areas		474.0	482.4	520.8	546.4
10	Less: Miscellaneous non-tariff revenues	A-8	6.7	6.4	4.5	4.5
11	Total Cost of Service - Electricity Distribution and Non-integrated areas		467.3	476.0	516.3	541.9
12	Shaded amounts indicate changes from the Revised Evidentiary Update.					

SCHEDULE C5 (Update of June 2004)

Cost of Service - Customer Care
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Cost of Service - Customer Care					
1	Customer Care OMA	D6	94.8	117.7	109.7	105.3
2	Less: Miscellaneous Non-tariff revenues 1	A-8	2.1	6.6	4.2	4.2
3	Total Cost of Service - Customer Care		92.7	111.1	105.5	101.1
	Allocation of Customer are Costs by Customer Group*					
4	Transmission-voltage		1.5	1.8	1.7	1.7
5	General Service and Residential		91.0	109.1	103.6	99.3
6	Other		0.2	0.2	0.2	0.1
7	Total Cost of Service - Customer Care		92.7	111.1	105.5	101.1
8	*Allocation percentages are based on direct spending costs:					
9	1.65% for Transmission customers					
10	98.20% for General Service & Residential customers					
11	0.15% for Other customers					
12	Notes:					
13	1. Composed of Terasen meter reading and other revenues.					
14	Shaded amounts indicate changes from the Revised Evidentiary Update.					

SCHEDULE C6 (Update of June 2004)

Cost of Service - Corporate
($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Cost of Service - Corporate					
1	OMA	D7	(16.2)	(71.0)	(56.2)	(56.2)
2	Taxes	B3	7.3	9.9	7.4	7.5
3	Depreciation and Amortization	B4	50.3	56.8	49.8	50.7
4	Finance Charges	B5	-	10.1	9.5	8.1
5	Restructuring costs	A-1	36.5	-	-	-
6	Total cost		77.9	5.8	10.5	10.1
7	Less: Miscellaneous Revenues	A-8	(12.9)	(14.5)	(10.5)	(10.1)
8	Cost of Service - Corporate		65.0	(8.7)	-	-

9 Notes:
10 The cost of service for F2003 largely relates to the restructuring costs and year-end write-offs and catch up of
11 depreciation which were not recovered through the corporate allocations.

12 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE C7 (Update of June 2004)

Cost of Service - Service Organizations and Subsidiaries [1]

($ millions)

Line	FISCAL 2003	Reference	Engineering	Field Services	MMBU	Powertech [2]	Other	Total
1	OMA expenses		(3.9)	(4.6)	(3.0)	10.3		(1.2)
2	Corporate Allocations		-	0.8				0.8
	Adjusted OMA including							
3	Corporate Allocations	D8, D9, D10	(3.9)	(3.8)	(3.0)	10.3	-	(0.4)
4	Depreciation	B4	0.8	10.9	0.6	0.6		12.9
5	Taxes	B3		0.2	0.8			1.0
6	Miscellaneous revenues	A-8		(6.9)		(13.0)	-	(19.9)
7			(3.1)	0.4	(1.6)	(2.1)	-	(6.4)

	FISCAL 2004	Reference	Engineering	Field Services	MMBU	Powertech	Other [3]	Total
8	OMA expenses		(8.0)	(19.8)	(1.2)	13.2		(15.8)
9	Corporate Allocations		7.7	15.0			2.3	25.0
	Adjusted OMA including							
10	Corporate Allocations	D8, D9, D10	(0.3)	(4.8)	(1.2)	13.2	2.3	9.2
11	Depreciation	B4	0.3	11.0	0.5	0.5		12.3
12	Taxes	B3		0.2	0.8			1.0
13	Miscellaneous revenues	A-8		(6.9)		(14.7)		(21.6)
14			-	(0.5)	0.1	(1.0)	2.3	0.9

	FISCAL 2005	Reference	Engineering [4]	Field Services [4]	MMBU	Powertech	Other [3]	Total
15	OMA expenses		(8.8)	(22.6)	0.6	13.1		(17.7)
16	Corporate Allocations		8.2	15.0			2.3	25.5
	Adjusted OMA including							
17	Corporate Allocations	D8, D9, D10	(0.6)	(7.6)	0.6	13.1	2.3	7.8
18	Depreciation	B4	0.3	12.5	0.7	0.7		14.2
19	Taxes	B3		0.2	0.9			1.1
20	Miscellaneous revenues	A-8		(6.6)		(15.0)		(21.6)
21			(0.3)	(1.5)	2.2	(1.2)	2.3	1.5

	FISCAL 2006	Reference	Engineering [4]	Field Services [4]	MMBU	Powertech	Other [3]	Total
22	OMA expenses		(8.8)	(23.6)	0.6	13.6		(18.2)
23	Corporate Allocations		8.2	15.0			2.3	25.5
	Adjusted OMA including							
24	Corporate Allocations	D8, D9, D10	(0.6)	(8.6)	0.6	13.6	2.3	7.3
25	Depreciation	B4	0.3	13.3	0.7	0.7		15.0
26	Taxes	B3		0.1	0.9			1.0
27	Miscellaneous revenues	A-8		(6.7)		(15.8)		(22.5)
28			(0.3)	(1.9)	2.2	(1.5)	2.3	0.8

29 Notes:
30 1. ABS costs are not included in this table and appear under OMA costs in each functional area.
31 2. Powertech information is from Chapter 9 Section 6.
32 3. Relates to allocation of corporate costs to Powerex. See Schedule E1.
33 4. Due to the decrease in depreciation as explained in Section 3.7, page 2A-10 of the June 2004 Update, Engineering
34 and Field Services show an over recovery of costs for the test year. The Engineering and Field Services charges to
35 the functions have not been adjusted as the over recovery is insignificant and there is no impact on the consolidated
36 revenue requirement.

37 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D1-1 (Update of June 2004)

Resource Usage - Generation (Heritage Contract)
($ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating, Maintenance, and Administration Expenses by Resource				
	Labour				
1	Direct	38.8	38.9	43.5	44.7
2	Indirect	21.7	25.4	24.5	24.1
3	Materials	9.0	7.1	6.7	6.7
	Internal Services				
4	Engineering	4.7	10.7	6.5	6.6
5	Field Services	7.7	7.7	11.2	11.2
6	BC Hydro Corporate Direct Charges	4.6	5.7	3.9	3.9
7	Other BC Hydro Billings	2.4	2.3	1.0	1.0
	External Services				
8	ABS 1	11.1	16.7	16.7	16.4
9	Other 2	25.0	46.5	21.3	21.2
10	Buildings & Equipment	1.0	1.1	0.8	0.8
11	Vehicles	0.2	0.4	0.2	0.1
12	Corporate Allocation	27.9	35.7	41.5	41.9
13	Less: Capitalized Overhead	(4.7)	(7.8)	(8.0)	(7.9)
	Less: Recoveries				
14	Internal	(0.5)	(4.4)	(2.8)	(2.8)
15	External	(1.5)	(1.9)	(0.1)	
16	Total OMA Expenses	147.4	184.1	166.9	167.9
	Operating, Maintenance, and Administration Expenses by Category				
17	Direct	72.6	95.5	75.8	77.8
18	Support	53.6	67.0	60.5	58.9
19	Corporate Allocations	27.9	35.7	41.5	41.9
20	Less: Capitalized Overhead	(4.7)	(7.8)	(8.0)	(7.9)
21	Less: Recoveries	(2.0)	(6.3)	(2.9)	(2.8)
22	Total OMA Expenses	147.4	184.1	166.9	167.9
	Capital Additions 3				
23	Sustaining	114.9	108.2	114.4	137.4
24	Growth	134.4	23.5	71.4	204.1
25	Deferred Capital	-	-	-	-
26	Total Capital Additions	249.3	131.7	185.8	341.5
27	CIA	(5.0)	-	-	-
28	Total Net Capital Additions	244.3	131.7	185.8	341.5

29 Notes:
30 1. Internal charges from the Shared Service organization that was outsourced to ABS in F2004 have been classified as ABS costs for F2003.
31 2. F2004 includes a valuation provision of $22 million relating to VIGP/GSX.
32 3. Includes GSX/VIGP (non-heritage assets) $57.7 million in 2005 and $192.6 million in 2006.

33 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D1-2 (Update of June 2004)

Domestic Cost of Energy - Generation (Heritage Contract)
For the Years Ended March 31
($ millions)

	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast	Reference
Domestic Cost of Energy - Generation					
Water Rentals	258.2	246.2	252.9	279.2	A-9
Market electricity purchases (Note 1)	104.4	299.9	343.0	222.3	A-9
Natural gas for thermal generation					
Burrard	17.4	21.8	15.2	15.5	A-9
Fort Nelson	10.7	10.9	13.0	12.0	A-9
Prince Rupert	0.1	-			A-9
Other					
System Operations Fund	(3.4)	(3.7)	(3.5)	-	A-9
Compensation and Mitigation Costs	6.8	7.0	7.2	7.3	A-9
	394.2	582.1	627.8	536.3	
Domestic Transmission-US portion	4.9	3.9	3.6	3.5	
Domestic Transmission-CDN portion	-	11.7	11.8	11.8	
	4.9	15.6	15.4	15.3	A-9
Total Domestic Cost of Energy - Generation	399.1	597.7	643.2	551.6	
Reconciliation of Domestic Cost of Energy - Generation to the cost of energy component of the Heritage Payment Obligation					
Domestic Cost of Energy - Generation (Heritage Contract)	399.1	597.7	643.2	551.6	
Displaced Hydro (Note 2)	5.4	(0.2)	(7.1)	(7.6)	
Electricity purchases - Powerex (Note 3)	(50.0)	(30.0)			
Cost of energy component of Heritage Payment Obligation	$354.5	$567.5	$636.1	$544.0	

Notes:
1. Includes electricity purchases from Powerex. See Note 3.
2. Displaced Hydro relates to water rentals associated with trade income.
3. This relates to energy purchases made by Powerex for future trade. This energy is sold to BC Hydro when it enters the system. BC Hydro records a sale to Powerex when the energy is returned. These are part of the Generation function but are not included in the Heritage Payment Obligation.

This schedule corresponds to Schedule D1-2 on page 2-80 of the Application. As in the Application, the costs shown on the Domestic Cost of Energy Schedule A-9, relating to IPP and long-term purchase commitments, net purchases from Powerex, non-integrated energy, gas transportation and congestion management are not Heritage energy. The remainder of the energy costs shown on Schedule A-9 relate to Heritage energy and tie into the schedule above.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D1-3 (Update of June 2004)

Forecast Heritage Payment Obligation
For the Years Ended March 31
($ millions)

	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast	Reference
Cost Components of Heritage Payment Obligation					
Cost of Energy component of Heritage Payment Obligation	$ 354.5	$ 567.5	$ 636.1	$ 544.0	D1-2
Operating Costs (Note 1)	147.4	162.1	166.9	167.9	
Depreciation and Amortization (Note 2)	110.7	118.3	129.0	124.9	
Taxes and Grants	29.0	28.2	28.6	29.0	
Finance Charges	213.0	197.0	190.5	201.0	
GRTA Expenses	37.0	43.3	43.3	43.3	
Gross Heritage Payment Obligation	891.6	1,116.4	1,194.4	1,110.1	
Less Other Revenues					
Skagit Valley Treaty	21.9	18.0	18.9	19.4	
Ancillary Services and Other Miscellaneous Revenue	5.3	5.4	7.3	8.4	
Total Other Revenues	27.2	23.4	26.2	27.8	
Net Costs	864.4	1,093.0	1,168.2	1,082.3	
Add: Return on Equity	195.0	183.4	193.3	194.8	
Forecast Heritage Payment Obligation	$ 1,059.4	$ 1,276.4	$ 1,361.5	$ 1,277.1	

Note 1:
Reconciliation of Generation Operating costs to Heritage Contract Operating costs for F2004.

Generation operating costs	184.1	B2
GSX/VIGP valuation provision	(22.0)	
Heritage contract operating costs	162.1	

Note 2:
Reconciliation of Generation Depreciation to Heritage Contract Depreciation for F2004.

Generation depreciation	216.3	B4
GSX/VIGP valuation provision	(98.0)	
Heritage contract depreciation	118.3	

The VIGP and GSX assets are part of the Generation function but are not part of the Heritage assets.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D1-4 (Update of June 2004)

Cost of Service - Generation (Heritage Contract) (reconciled with cost of energy component from Heritage Payment Obligation)

($ millions)

Line		Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Cost of Service - Generation (Heritage Contract)					
1	Cost of Energy component of Heritage Payment Obligation	D1-3	$ 354.5	$ 567.5	$ 636.1	$ 544.0
2	Displaced Hydro	D1-2	(5.4)	0.2	7.1	7.6
3	Electricity purchases Powerex	D1-2	50.0	30.0		
4	Domestic cost of energy-Generation (Heritage Contract)	D1-2	399.1	597.7	643.2	551.6
5	Generation OMA	D1-1	147.4	184.1	166.9	167.9
6	GRTA charges from Transmission	C3	37.0	43.3	43.3	43.3
7	Taxes	B3	29.0	28.2	28.6	29.0
8	Depreciation and Amortization	B4	110.7	216.3	129.0	124.9
9	Finance Charges	B5	213.0	197.0	190.5	201.0
10	Allowed return on equity	B6	195.0	183.4	193.3	194.8
11	Total Cost		1,131.2	1,450.0	1,394.8	1,312.5
12	Less: Trade Income	A-1	138.0	158.0	89.0	91.0
13	Other Utilities		21.9	18.0	18.9	19.4
14	Other miscellaneous Non-tariff revenues	A-8	5.3	5.4	7.3	8.4
15			165.2	181.4	115.2	118.8
16	Total Cost of Service - Generation	C1	$ 966.0	$ 1,268.6	$ 1,279.6	$ 1,193.7

17 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D2 (Update of June 2004)

Resource Usage - Energy Management [1]
($ Millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating Maintenance and Administration Expenses by Resources				
	Labour				
1	Direct	2.3	4.2	4.9	5.0
2	Indirect	1.3	1.3	1.7	1.7
3	Materials	-	0.1	0.1	0.1
	Internal Services				
4	Engineering	0.7	1.4	0.1	0.1
5	Field Services	-	(0.1)	0.1	0.1
6	BC Hydro Corporate Direct Charges	0.5	1.6	0.3	0.3
7	Other BCH Billlings	0.4	0.4	0.2	0.2
	External Services				
8	ABS	0.5	1.5	1.5	1.5
9	Other	1.4	4.4	3.4	1.6
10	Buildings & Equipment	0.1	0.1	0.1	0.1
11	Vehicles	-	-	-	-
12	Corporate Allocation	0.3	0.3	0.5	0.4
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	-	-	(0.1)	(0.1)
15	External	(0.2)	(0.9)	-	-
16	Total OMA Expenses	7.3	14.3	12.8	11.0
	Operating Maintenance and Administration Expenses by Category				
17	Direct	4.0	9.9	8.7	6.9
18	Support	3.2	5.0	3.7	3.8
19	Corporate Allocations	0.3	0.3	0.5	0.4
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(0.2)	(0.9)	(0.1)	(0.1)
22	Total OMA Expenses	7.3	14.3	12.8	11.0
	Capital Additions				
23	Sustaining	2.8	0.4	0.3	1.4
24	Growth	1.1	0.3	-	-
25	Deferred Capital	0.2	-	-	-
26	Total Capital Gross of CIA	4.1	0.7	0.3	1.4
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	4.1	0.7	0.3	1.4

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D3 (Update of June 2004)

Resource Usage - Powersmart [1]
($ Millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating Maintenance and Administration Expenses by Resources				
	Labour				
1	Direct	2.2	3.0	2.0	2.1
2	Indirect	1.3	0.7	1.4	1.4
3	Materials	-	0.3	0.1	0.1
	Internal Services				
4	Engineering	-	0.2	0.2	0.2
5	Field Services	-	2.1	2.0	2.0
6	BC Hydro Corporate Direct Charges	(0.5)	0.4	0.3	0.3
7	Other BCH Billlings	1.0	1.6	1.5	1.5
	External Services				
8	ABS	0.9	3.0	3.3	3.1
9	Other	0.6	0.7	0.4	0.4
10	Buildings & Equipment	-	-	-	0.1
11	Vehicles	0.1	-	-	-
12	Corporate Allocation	7.3	8.9	11.8	11.5
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	-	-	(0.9)	(0.9)
15	External	(0.1)	(0.7)	-	-
16	Total OMA Expenses	12.8	20.2	22.1	21.8
	Operating Maintenance and Administration Expenses by Category				
17	Direct	2.8	5.9	4.5	4.6
18	Support	2.8	6.1	6.7	6.6
19	Corporate Allocations	7.3	8.9	11.8	11.5
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(0.1)	(0.7)	(0.9)	(0.9)
22	Total OMA Expenses	12.8	20.2	22.1	21.8
	Capital Additions				
23	Sustaining	1.5	1.5	-	0.8
24	Growth	0.0	6.2	1.5	1.6
25	Deferred Capital	44.5	62.6	105.0	93.8
26	Total Capital Gross of CIA	46.0	70.3	106.5	96.1
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	46.0	70.3	106.5	96.1

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D4 Resource Usage (Update of June 2004)

Resource Usage - Transmission
($ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast BC Hydro	F2006 Forecast BCTC
	Operating, Maintenance, and Administration Expenses by Resource					
	Labour					
1	Direct	17.5	23.4	28.1		28.6
2	Indirect	7.4	7.2	11.2		11.4
3	Materials	8.2	4.7	4.4		4.4
	BC Hydro Services					
4	Engineering	12.7	17.4	14.2		14.2
5	Field Services	63.0	75.0	69.2		69.2
6	BC Hydro Corporate Direct Charges	3.0	3.2	5.7	4.8	0.9
7	Other BC Hydro Billings	5.9	7.0	3.8		4.9
	External Services					
8	ABS*	7.9	12.8	10.0		10.6
9	Other	16.7	18.3	29.5		28.0
10	Buildings & Equipment	1.6	2.0	2.9		2.8
11	Vehicles	0.1	-	0.1		0.1
12	Corporate Allocation	28.0	22.7	14.1	14.3	
13	Less: Capitalized Overhead	(5.2)	(5.1)	(5.2)		(5.2)
	Less: Recoveries					
14	Internal	(6.8)	(6.4)	(6.3)	(1.3)	(3.7)
15	External	(1.8)	(0.1)	(0.1)		(0.1)
16	Total OMA Expenses	158.2	182.1	181.6	17.8	166.1
	Operating, Maintenance, and Administration Expenses by Category					
17	Direct	123.7	145.7	154.0	4.8	151.1
18	Support	20.3	25.3	25.1		24.0
19	Corporate Allocations	28.0	22.7	14.1	14.3	
20	Less: Capitalized Overhead	(5.2)	(5.1)	(5.2)		(5.2)
21	Less: Recoveries	(8.6)	(6.5)	(6.4)	(1.3)	(3.8)
22	Total OMA Expenses	158.2	182.1	181.6	17.8	166.1
	Capital Expenditures					
23	Sustaining	99.1	138.8	155.0	104.0	43.0
24	Growth	68.0	47.2	89.0	162.0	
25	CIA	(12.2)	(9.7)	(8.0)	(9.0)	
26	Total Capital Expenditures	154.9	176.3	236.0	257.0	43.0

27 * Internal charges from the Shared Service organization that was outsourced to ABS in fiscal 2004 have been classified as ABS costs
28 for fiscal 2003 even though the outsourcing did not occur until fiscal 2004.

29 F2004 includes $8.3 million relating to restructuring costs.

30 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D5 (Update of June 2004)

Resource Usage - Electricity Distribution and Non-Integrated Areas
($ Millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating Maintenance and Administration Expenses by Resources				
	Labour				
1	Direct	22.2	27.1	26.4	27.0
2	Indirect	4.7	4.2	5.2	4.8
3	Materials	3.8	2.9	4.3	4.5
	Internal Services				
4	Engineering	4.2	8.2	7.2	7.6
5	Field Services	64.2	81.1	81.5	81.1
6	BC Hydro Corporate Direct Charges	5.9	3.3	3.9	3.9
7	Other BCH Billlings	4.2	5.0	3.7	3.7
	External Services				
8	ABS	7.7	14.8	14.9	14.7
9	Other	8.2	8.0	7.0	7.4
10	Buildings & Equipment	2.1	2.5	1.9	2.1
11	Vehicles	1.1	0.7	0.9	0.9
12	Corporate Allocation	15.3	18.7	25.0	24.4
13	Less: Capitalized Overhead	(35.0)	(39.2)	(42.0)	(42.7)
	Less: Recoveries				
14	Internal	(0.2)	(1.9)	(1.0)	(0.5)
15	External	(6.4)	(7.4)	(6.5)	(6.9)
16	Total OMA Expenses	102.0	128.0	132.4	132.0
	Operating Maintenance and Administration Expenses by Category				
17	Direct	105.7	129.6	130.6	131.9
18	Support	22.6	28.3	26.3	25.8
19	Corporate Allocations	15.3	18.7	25.0	24.4
20	Less: Capitalized Overhead	(35.0)	(39.2)	(42.0)	(42.7)
21	Less: Recoveries	(6.6)	(9.4)	(7.5)	(7.4)
	Total OMA Expenses	102.0	128.0	132.4	132.0
	Capital Additions				
23	Sustaining	60.7	78.7	86.1	88.9
24	Growth	119.8	119.6	123.4	130.9
25	Deferred Capital	0.1	-	-	-
26	Total Capital Gross of CIA	180.6	198.3	209.5	219.8
27	Sustaining CIA	(8.6)	(1.8)	(4.2)	(3.8)
28	Growth CIA	(35.9)	(44.2)	(38.3)	(41.0)
29	Total CIA	(44.5)	(46.0)	(42.6)	(44.8)
30	Total Net Capital	136.1	152.3	167.0	175.0

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D6 (Update of June 2004)

Resource Usage - Customer Care
($ Millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating Maintenance and Administration Expenses by Resources				
	Labour				
1	Direct	2.5	2.9	3.2	3.3
2	Indirect	1.3	1.3	1.3	1.3
3	Materials	0.3	0.6	0.3	0.4
	Internal Services				
4	Engineering	-	0.2	0.2	0.2
5	Field Services	0.1	1.4	1.4	1.4
6	BC Hydro Corporate Direct Charges	1.7	0.6	0.6	0.6
7	Other BCH Billlings	1.0	0.8	0.5	0.5
	External Services				
8	ABS	80.8	93.4	91.7	87.3
9	Other	13.0	16.6	9.3	9.3
10	Buildings & Equipment	2.2	0.1	0.1	0.1
11	Vehicles	0.1	-	-	-
12	Corporate Allocation	5.0	6.1	8.2	8.0
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	(0.8)	(1.4)	(1.7)	(1.7)
15	External	(12.4)	(4.9)	(5.4)	(5.4)
16	Total OMA Expenses	94.8	117.7	109.7	105.3
	Operating Maintenance and Administration Expenses by Category				
17	Direct	92.2	106.8	103.9	99.8
18	Support	10.8	11.1	4.7	4.6
19	Corporate Allocations	5.0	6.1	8.2	8.0
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(13.2)	(6.3)	(7.1)	(7.1)
	Total OMA Expenses	94.8	117.7	109.7	105.3
	Capital Additions				
23	Sustaining	28.6	19.2	3.8	5.7
24	Growth	-	-	-	-
25	Deferred Capital	-	-	-	-
26	Total Capital Gross of CIA	28.6	19.2	3.8	5.7
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	28.6	19.2	3.8	5.7

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D7 (Update of June 2004)

Resource Usage Corporate

($ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating, Maintenance, and Administration Expenses by Resource				
	Labour				
1	Direct	37.2	30.3	32.7	33.2
2	Non-current pension costs - total BCH	30.7	49.3	48.0	47.0
3	Materials	1.0	1.0	0.9	0.9
	Internal Services				
4	Engineering	0.3	1.0	0.1	0.1
5	Field Services including Fleet	0.8	1.9	1.8	1.8
6	Properties/Phones/Rent/Furniture	2.2	8.0	8.2	8.2
7	Inter LOB, Legal, BCH SAC	2.5	11.8	10.6	10.8
	External Services				
8	ABS	12.7	17.7	17.0	16.4
9	Other	30.1	57.6	37.5	33.0
10	Buildings & Equipment	3.4	2.7	3.0	3.5
11	Vehicles	0.0	0.0	0.0	0.0
12	Accruals, Provisions, Adjustments	(3.5)	(16.7)	6.0	6.3
13	Plus: Westech net OMA	(0.9)	3.2	3.0	3.0
14	Less: Capitalized Overhead	0.0	0.0	0.0	0.0
15	Less: External recoveries	(0.8)	(13.7)	(2.9)	(2.9)
16	Less: Internal Recoveries	(31.8)	(71.2)	(51.1)	(49.7)
17	Less: Shared Services net	(15.5)			
18	Less: BCH SAC internal recoveries		(36.4)	(44.4)	(41.8)
19	Total OMA Expenses	68.4	46.5	70.4	69.8
20	Corporate Resources Allocated	(84.6)	(117.5)	(126.6)	(126.0)
21	Net OMA Expenses	(16.2)	(71.0)	(56.2)	(56.2)
	Capital Additions (including BCH SAC, Powertech)				
22	Sustaining - in Corporate	43.5	8.7	18.9	28.8
23	Growth	0.0	0.0	0.0	0.0
24	Deferred Capital	0.2	0.0	0.0	0.0
25	Total Capital Gross of CIA	43.7	8.7	18.9	28.8
26	Sustaining CIA	0.0	0.0	0.0	0.0
27	Total Net Capital	43.7	8.7	18.9	28.8

28 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D8 (Update of June 2004)

Resource Usage - Engineering
($ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating, Maintenance, and Administration Expenses by Resource				
	Labour				
1	Direct	46.1	48.0	48.4	50.0
2	Indirect	12.3	10.4	10.3	10.7
3	Materials	1.2	1.1	0.7	0.6
	Internal Services				
4	Field Services	0.7	0.3	0.3	0.3
5	Corporate Direct Charges	1.1	2.8	2.0	2.0
	Other Internal Billings				
	External Services				
6	ABS 1	10.0	12.9	12.3	11.9
7	Other 2	3.3	8.8	11.5	11.1
8	Buildings & Equipment	0.8	1.1	1.4	1.2
9	Vehicles	0.2	0.2	0.1	0.1
10	Corporate Allocation	-	7.7	8.2	8.2
11	Less: Capitalized Overhead				
	Less: Recoveries				
12	Internal	(75.9)	(90.5)	(94.1)	(95.0)
13	External	(3.7)	(3.1)	(1.7)	(1.7)
14	Total OMA Expenses	(3.9)	(0.3)	(0.6)	(0.6)
	Operating, Maintenance, and Administration Expenses by Category				
15	Direct	49.4	57.7	61.3	62.6
16	Support	26.3	27.9	25.7	25.3
17	Corporate Allocations		7.7	8.2	8.2
18	Less: Capitalized Overhead				
19	Less: Recoveries	(79.6)	(93.6)	(95.8)	(96.7)
20	Total OMA Expenses	(3.9)	(0.3)	(0.6)	(0.6)
	Capital Additions				
21	Sustaining	1.8	1.1	1.0	1.0
22	Growth				
23	Deferred Capital				
24	Total Capital Additions	1.8	1.1	1.0	1.0

25 Notes:
26 (1) For comparative purposes, F2003 actual have been reclassified to reflect the creation of ABS.
27 (2) F2003 excludes costs for Contract Hires and Consultants
28 (3) F2004 to F2006 estimate includes Non-Service Pension Costs of $8.2M in the Recoveries
29 These amounts will be allocated through a surcharge via Journal Voucher
30 directly to the functions.

SCHEDULE D9 (Update of June 2004)

Resource Usage - Field Services
($ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating, Maintenance, and Administration Expenses by Resource				
	Labour				
1	Direct	$93.5	$102.8	$94.7	$ 96.3
2	Indirect	46.7	43.0	44.0	44.6
3	Materials	15.5	16.0	15.0	14.5
	Internal Services				
4	Engineering	0.2	0.7	0.5	0.5
5	Corporate Direct Charges	1.0	4.3	3.4	3.5
6	Other Internal Billings	-	0.9	0.4	0.4
7	External Services				
8	ABS	16.1	21.8	21.9	21.1
9	Other	76.9	94.0	96.9	97.8
10	Buildings & Equipment	3.1	4.4	3.9	3.9
11	Vehicles	1.8	1.2	1.1	0.6
12	Corporate Allocation	0.8	15.0	15.0	15.0
13	Less: Capitalized Overhead				
	Less: Recoveries				
14	Internal	(255.6)	(296.5)	(291.8)	(295.1)
15	External	(3.8)	(12.4)	(12.6)	(11.7)
16	Total OMA Expenses	($3.8)	($4.8)	($7.6)	($8.6)
	Operating, Maintenance, and Administration Expenses by Category				
17	Direct	161.7	213.8	213.1	214.7
18	Support	93.1	75.3	68.7	68.5
19	Corporate Allocations	0.8	15.0	15.0	15.0
20	Less: Capitalized Overhead				
21	Less: Recoveries	(259.4)	(308.9)	(304.4)	(306.8)
22	Total OMA Expenses	($3.8)	($4.8)	($7.6)	($8.6)
	Capital Additions				
23	Sustaining	16.9	16.4	22.5	21.4
24	Growth				
25	Deferred Capital				
26	Total Capital Additions	$16.9	$16.4	$22.5	$21.4

27 Note: F2004 Actual Internal Recoveries includes CBU/SOBU depreciation.

28 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE D10 (Update of June 2004)

Resource Usage - MMBU
($ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
	Operating Maintenance and Administration Expenses by Resources				
	Labour				
1	Direct	7.2	7.5	7.8	8.0
2	Indirect	0.2	-	-	-
3	Materials	0.4	1.4	0.7	0.7
	Internal Services				
4	Engineering	1.1	1.3	1.2	1.2
5	Field Services	2.8	2.9	1.2	1.2
6	BC Hydro Corporate Direct Charges	0.3	0.3	0.2	0.2
7	Other BCH Billlings	1.8	2.3	2.1	2.1
	External Services				
8	ABS	2.0	3.1	5.9	5.9
9	Other	3.0	6.1	6.5	6.3
10	Buildings & Equipment	0.2	0.1	0.1	0.1
11	Vehicles	1.3	1.3	1.3	1.3
12	Corporate Allocation	-	-	-	-
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	(22.5)	(25.4)	(25.4)	(25.4)
15	External	(0.8)	(2.1)	(1.0)	(1.0)
16	Total OMA Expenses	(3.0)	(1.2)	0.6	0.6
	Operating Maintenance and Administration Expenses by Category				
17	Direct	17.7	23.5	23.5	23.6
18	Support	2.6	2.8	3.5	3.4
19	Corporate Allocations	-	-	-	-
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(23.3)	(27.5)	(26.4)	(26.4)
22	Total OMA Expenses	(3.0)	(1.2)	0.6	0.6
	Capital Additions				
23	Sustaining	-	1.0	0.8	0.5
24	Growth	0.0	-	-	-
25	Deferred Capital	-	0.1	-	-
26	Total Capital Gross of CIA	0.0	1.1	0.8	0.5
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	0.0	1.1	0.8	0.5

BC HYDRO UNDERTAKING

BC HYDRO REVENUE REQUIREMENT HEARING
2004/05 AND 2005/06

HEARING DATE

Wednesday, June 9, 2004

TRANSCRIPT REFERENCE

Volume 20, pages 3583-3591

REQUESTOR: Commission Chair

QUESTION

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).

RESPONSE

BC Hydro's June Financial Undertaking reflects changes in a number of key assumptions since the Evidentiary Update was filed on April 2, 2004. These include: domestic load forecast increases of approximately 900 GWh for each of F2005 and F2006, adjusted for losses, together with a reduced inflow forecast to approximately 89% of average, system wide, and a reduction of approximately 200 GWh from IPPs, mainly due to an Arrow Lakes Hydro outage.

The results of the supporting Marginal Cost Model Study (MCM) to the June Evidentiary Undertaking confirm that there is limited flexibility to materially alter F2005 operations because of expected low inflows; expected low reservoir levels; potential impacts on other stakeholders; and increased exposure to higher cost market purchases. This conclusion is supported by the information that follows.

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 32 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 average 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 Hydro 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. The 2,147 feet elevation has also been adopted in the draft Water Use Plan as the acceptable minimum in normal operating conditions. Nevertheless, these industries have focussed on the 2,150 feet. Given the timing of the potential low elevations in F2005, 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 levelling 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 potential risk mitigation against the possibility of low flows in F2006. As it is, there is essentially no additional reservoir storage available to mitigate the costs and impacts of low flows in F2006.
- It is not appropriate to plan to draft a major reservoir, such as Mica, right to water license minimums because of the potential for delayed run-off and the fact that generation would be limited to/by available inflow as this would result in an unacceptable level of risk to system reliability.

The optimization of system operations over BC Hydro Generation's planning horizon is based on a number of inputs, constraints, models and risk assessments that minimize the cost of energy to ratepayers within an acceptable risk profile. This optimization is done on a near-constant basis in response to new information. In BC Hydro's judgement, informed by this system optimization process, and the current constraints and reliability concerns, it is not prudent to draft reservoirs materially lower than currently forecast in F2005.

REVISED
BC HYDRO UNDERTAKING

BC HYDRO REVENUE REQUIREMENT HEARING
2004/05 AND 2005/06

HEARING DATE

June 8, 2004

TRANSCRIPT REFERENCE

Volume 19, Page 3297-3298

REQUESTOR: IPPBC

QUESTION

For Peace Site C, Mica 5, and Revelstoke 5, provide the information that was used in the IEP assessment, by providing a breakdown of the cash flow year by year of the capital cost and operating cost.

REVISED RESPONSE:

The purpose of this revision is to correct the titles and units of measure in Tables 4 to 6.

The attached Tables 1 to 3 show a breakdown of the major capital cost elements for Site C, Mica 5 and Revelstoke 5, respectively. These capital costs are shown in the 2004 IEP Part 3 Appendix F. Unit costs are provided using a 6 percent real discount rate and based on the economic life of the projects. The use of a higher discount rate or shorter amortization period would increase the unit cost. Table 4 provides a year by year cash flow of costs for Site C. Table 4 includes grants-in-lieu and water rental capacity charges that were inadvertently excluded in the IEP portfolio analysis.

Table 5 provides a year by year cash flow of the costs for Mica 5. Table 5 includes water rental capacity charges that were inadvertently excluded in the IEP portfolio analysis. However, Table 5 does not include any water rental charges or credits for the additional 50 GWh/yr gained at Mica.

Table 6 provides a year by year cash flow of the costs for Revelstoke 5. Table 6 includes water rental capacity charges that were inadvertently excluded in the IEP portfolio analysis. However, Table 6 does not include any water rental charges or credits for the additional 60 GWh/yr gained at Revelstoke.

TABLE 1

Project Name **Site C**

	2003$ millions
Lands & Rights and Reservoir Cost	122.2
Site Access & Clearing	28.6
Excavation, Cofferdams and Diversion Tunnels	232.0
Earthfill Dam	204.0
Spillway & Approach Channels	275.3
Power Intakes & Penstocks	171.5
Power House - Civil	158.8
Power House - Mechanical	127.1
Power House - Electrical	133.4
Switchgear Bldg (Electrical & Mechanical Include)	56.6
Construction Services	50.2
Direct Construction Cost	1559.8
Management & Engineering	223.8
Regulatory, First Nation and Mit & Comp	62.3
Construction Insurance	7.7
Contingency	215.4
Indirect Construction Cost	509.2
Total Generation Station	2069.0
Stations and Transmission (Site C to Peace Canyon)	69.0
Total Construction Cost	2138.0

Notes:
- Capital costs do not include corporate overhead and IDC

TABLE 2

Project Name **Mica 5**

	2003$ millions
Powerhouse Civil	10.4
Powerhouse Mechanical	20.9
Powerhouse Electrical	62.5
Construction Services	1.8
Direct Construction Cost	95.8
Contingencies	9.8
Mitigation & Compensation	1.3
Management and Engineering	12.3
Construction Insurance and Bonds	1.0
Indirect Construction Cost	24.5
Total Construction Cost	120.3

Notes:
- Source: Mar 2003 capital cost estimate
- Capital cost in 2002$ were escalated to 2003$ using Statistics Canada Inflation Rate (2003$=118.1/115.3*2002$)
- Capital costs do not include corporate overhead and IDC

TABLE 3

Project Name **Rev 5**

	2003$ millions
General	0.6
Penstock	4.5
Powerhouse Civil	7.8
Powerhouse Mechanical	28.7
Powerhouse Electrical	36.8
Construction Services	2.6
Direct Construction Cost	81.0
Contingencies	6.1
Mitigation & Compensation	1.7
Management and Engineering	16.1
Construction Insurance and Bonds	0.4
Indirect Construction Cost	24.4
Total Construction Cost	105.4

Notes:
- Source: Mar 2003 capital cost estimate
- Capital cost in 2002$ were escalated to 2003$ using Statistics Canada Inflation Rate (2003$=118.1/115.3*2002$)
- Capital costs do not include corporate overhead and IDC

TABLE 4 **AT SITE UNIT ENERGY COST** c

Project Name **Site C**

Capacity	900	MW
Average Energy	4780	GWh
Water Rentals (energy)	4.835	$/MWh
Water Rentals (capacity)	3.453	$/kW
Discount Rate	6%	

Year	Energy (GWh/yr)	Capital ($k)	O&M ($k)	Taxes and Grants-In-Lieu ($k)	Water Rentals Energy ($k)	Water Rentals Capacity ($k)	Total Costs ($k)
-9	-	5,986	-	-	-	-	5,986
-8	-	28,863	-	-	-	-	28,863
-7	-	236,249	-	-	-	-	236,249
-6	-	421,186	-	-	-	-	421,186
-5	-	418,193	-	-	-	-	418,193
-4	-	450,904	-	-	-	-	450,904
-3	-	320,914	-	-	-	-	320,914
-2	-	152,653	-	-	-	-	152,653
-1	-	90,865	-	-	-	-	90,865
0	4,780	11,973	11,100	482	23,111	3,108	49,773
1	4,780	-	11,100	482	23,111	3,108	37,801
2	4,780	-	11,100	482	23,111	3,108	37,801
3	4,780	-	11,100	482	23,111	3,108	37,801
4	4,780	-	11,100	482	23,111	3,108	37,801
5	4,780	-	11,100	482	23,111	3,108	37,801
6	4,780	-	11,100	482	23,111	3,108	37,801
7	4,780	-	11,100	482	23,111	3,108	37,801
8	4,780	-	11,100	482	23,111	3,108	37,801
9	4,780	-	11,100	482	23,111	3,108	37,801
10	4,780	-	11,100	482	23,111	3,108	37,801
11	4,780	-	11,100	482	23,111	3,108	37,801
12	4,780	-	11,100	482	23,111	3,108	37,801
13	4,780	-	11,100	482	23,111	3,108	37,801
14	4,780	-	11,100	482	23,111	3,108	37,801
15	4,780	-	11,100	482	23,111	3,108	37,801
16	4,780	-	11,100	482	23,111	3,108	37,801
17	4,780	-	11,100	482	23,111	3,108	37,801
18	4,780	-	11,100	482	23,111	3,108	37,801
19	4,780	-	11,100	482	23,111	3,108	37,801
20	4,780	-	11,100	482	23,111	3,108	37,801
21	4,780	-	11,100	482	23,111	3,108	37,801
22	4,780	-	11,100	482	23,111	3,108	37,801
23	4,780	-	11,100	482	23,111	3,108	37,801
24	4,780	-	11,100	482	23,111	3,108	37,801
25	4,780	-	11,100	482	23,111	3,108	37,801
26	4,780	-	11,100	482	23,111	3,108	37,801
27	4,780	-	11,100	482	23,111	3,108	37,801
28	4,780	-	11,100	482	23,111	3,108	37,801
29	4,780	-	11,100	482	23,111	3,108	37,801
30	4,780	-	11,100	482	23,111	3,108	37,801
31	4,780	-	11,100	482	23,111	3,108	37,801
32	4,780	-	11,100	482	23,111	3,108	37,801
33	4,780	-	11,100	482	23,111	3,108	37,801
34	4,780	-	11,100	482	23,111	3,108	37,801
35	4,780	-	11,100	482	23,111	3,108	37,801
36	4,780	-	11,100	482	23,111	3,108	37,801
37	4,780	-	11,100	482	23,111	3,108	37,801
38	4,780	-	11,100	482	23,111	3,108	37,801
39	4,780	-	11,100	482	23,111	3,108	37,801
40	4,780	-	11,100	482	23,111	3,108	37,801
41	4,780	-	11,100	482	23,111	3,108	37,801
42	4,780	-	11,100	482	23,111	3,108	37,801
43	4,780	-	11,100	482	23,111	3,108	37,801
44	4,780	-	11,100	482	23,111	3,108	37,801
45	4,780	-	11,100	482	23,111	3,108	37,801
46	4,780	-	11,100	482	23,111	3,108	37,801
47	4,780	-	11,100	482	23,111	3,108	37,801
48	4,780	-	11,100	482	23,111	3,108	37,801
49	4,780	-	11,100	482	23,111	3,108	37,801
50	4,780	-	11,100	482	23,111	3,108	37,801
51	4,780	-	11,100	482	23,111	3,108	37,801
52	4,780	-	11,100	482	23,111	3,108	37,801
53	4,780	-	11,100	482	23,111	3,108	37,801
54	4,780	-	11,100	482	23,111	3,108	37,801
55	4,780	-	11,100	482	23,111	3,108	37,801
56	4,780	-	11,100	482	23,111	3,108	37,801
57	4,780	-	11,100	482	23,111	3,108	37,801
58	4,780	-	11,100	482	23,111	3,108	37,801
59	4,780	-	11,100	482	23,111	3,108	37,801
60	4,780	-	11,100	482	23,111	3,108	37,801
61	4,780	-	11,100	482	23,111	3,108	37,801
62	4,780	-	11,100	482	23,111	3,108	37,801
63	4,780	-	11,100	482	23,111	3,108	37,801
64	4,780	-	11,100	482	23,111	3,108	37,801
65	4,780	-	11,100	482	23,111	3,108	37,801
66	4,780	-	11,100	482	23,111	3,108	37,801
67	4,780	-	11,100	482	23,111	3,108	37,801
68	4,780	-	11,100	482	23,111	3,108	37,801
69	4,780	-	11,100	482	23,111	3,108	37,801

Project Life: 70 years
NPV: 46,356

1,929,941
42 $/MWh c

Project Life: 20 years
NPV: 32,452

1,819,981
56 $/MWh n

Notes:
- Costs are $2003
- Capital costs do not include corporate overhead
- IDC is accounted for in discounting of cash flows

TABLE 5 **AT SITE UNIT COST OF CAPACITY** c

Project Name **Mica 5**

Dependable Capacity	400	MW
Rated Capacity	450	MW
Water Rentals (capacity	3.453	$/kW
Discount Rate	6%	

Year	Dependable Capacity (MW)	Capital ($k)	O&M ($k)	Taxes and Grants-In-Lieu ($k)	Water Rentals Capacity ($k)	Total Costs ($k)
-5	-	1,263	-	-	-	1,263
-4	-	10,726	-	-	-	10,726
-3	-	22,150	-	-	-	22,150
-2	-	56,542	-	-	-	56,542
-1	-	29,233	-	-	-	29,233
0	400	337	906	241	1,554	3,038
1	400	-	906	241	1,554	2,701
2	400	-	906	241	1,554	2,701
3	400	-	906	241	1,554	2,701
4	400	-	906	241	1,554	2,701
5	400	-	906	241	1,554	2,701
6	400	-	906	241	1,554	2,701
7	400	-	906	241	1,554	2,701
8	400	-	906	241	1,554	2,701
9	400	-	906	241	1,554	2,701
10	400	-	906	241	1,554	2,701
11	400	-	906	241	1,554	2,701
12	400	-	906	241	1,554	2,701
13	400	-	906	241	1,554	2,701
14	400	-	906	241	1,554	2,701
15	400	-	906	241	1,554	2,701
16	400	-	906	241	1,554	2,701
17	400	-	906	241	1,554	2,701
18	400	-	906	241	1,554	2,701
19	400	-	906	241	1,554	2,701
20	400	-	906	241	1,554	2,701
21	400	-	906	241	1,554	2,701
22	400	-	906	241	1,554	2,701
23	400	-	906	241	1,554	2,701
24	400	-	906	241	1,554	2,701
25	400	-	906	241	1,554	2,701
26	400	-	906	241	1,554	2,701
27	400	-	906	241	1,554	2,701
28	400	-	906	241	1,554	2,701
29	400	-	906	241	1,554	2,701
30	400	-	906	241	1,554	2,701
31	400	-	906	241	1,554	2,701
32	400	-	906	241	1,554	2,701
33	400	-	906	241	1,554	2,701
34	400	-	906	241	1,554	2,701
35	400	-	906	241	1,554	2,701
36	400	-	906	241	1,554	2,701
37	400	-	906	241	1,554	2,701
38	400	-	906	241	1,554	2,701
39	400	-	906	241	1,554	2,701
40	400	-	906	241	1,554	2,701
41	400	-	906	241	1,554	2,701
42	400	-	906	241	1,554	2,701
43	400	-	906	241	1,554	2,701
44	400	-	906	241	1,554	2,701
45	400	-	906	241	1,554	2,701
46	400	-	906	241	1,554	2,701
47	400	-	906	241	1,554	2,701
48	400	-	906	241	1,554	2,701
49	400	-	906	241	1,554	2,701

Project Life: 50 years
NPV: 4,711

128,012
27 $/kW-yr c

Notes:
- Costs are $2003
- Capital costs do not include corporate overhead
- IDC is accounted for in discounting of cash flows
- No water rental charges or credits for additional 50 GWh/yr at Mica is included
- Taxes and Grant-in-Lieu and Water Rentals are based on Rated Capacity

TABLE 6 **AT SITE UNIT COST OF CAPACITY**

Project Name **Rev 5**

Dependable Capacity	480	MW
Rated Capacity	500	MW
Water Rentals (capacity)	3.453	$/kW
Discount Rate	6%	

Year	Dependable Capacity (MW)	Capital ($k)	O&M ($k)	Taxes and Grants-In-Lieu ($k)	Water Rentals Capacity ($k)	Total Costs ($k)
-4	-	9,802	-	-	-	9,802
-3	-	30,566	-	-	-	30,566
-2	-	52,700	-	-	-	52,700
-1	-	12,332	-	-	-	12,332
0	480	-	692	268	1,727	2,686
1	480	-	692	268	1,727	2,686
2	480	-	692	268	1,727	2,686
3	480	-	692	268	1,727	2,686
4	480	-	692	268	1,727	2,686
5	480	-	692	268	1,727	2,686
6	480	-	692	268	1,727	2,686
7	480	-	692	268	1,727	2,686
8	480	-	692	268	1,727	2,686
9	480	-	692	268	1,727	2,686
10	480	-	692	268	1,727	2,686
11	480	-	692	268	1,727	2,686
12	480	-	692	268	1,727	2,686
13	480	-	692	268	1,727	2,686
14	480	-	692	268	1,727	2,686
15	480	-	692	268	1,727	2,686
16	480	-	692	268	1,727	2,686
17	480	-	692	268	1,727	2,686
18	480	-	692	268	1,727	2,686
19	480	-	692	268	1,727	2,686
20	480	-	692	268	1,727	2,686
21	480	-	692	268	1,727	2,686
22	480	-	692	268	1,727	2,686
23	480	-	692	268	1,727	2,686
24	480	-	692	268	1,727	2,686
25	480	-	692	268	1,727	2,686
26	480	-	692	268	1,727	2,686
27	480	-	692	268	1,727	2,686
28	480	-	692	268	1,727	2,686
29	480	-	692	268	1,727	2,686
30	480	-	692	268	1,727	2,686
31	480	-	692	268	1,727	2,686
32	480	-	692	268	1,727	2,686
33	480	-	692	268	1,727	2,686
34	480	-	692	268	1,727	2,686
35	480	-	692	268	1,727	2,686
36	480	-	692	268	1,727	2,686
37	480	-	692	268	1,727	2,686
38	480	-	692	268	1,727	2,686
39	480	-	692	268	1,727	2,686
40	480	-	692	268	1,727	2,686
41	480	-	692	268	1,727	2,686
42	480	-	692	268	1,727	2,686
43	480	-	692	268	1,727	2,686
44	480	-	692	268	1,727	2,686
45	480	-	692	268	1,727	2,686
46	480	-	692	268	1,727	2,686
47	480	-	692	268	1,727	2,686
48	480	-	692	268	1,727	2,686
49	480	-	692	268	1,727	2,686

Project Life: 50 years
NPV: 5,993

124,001
21 $/kW-yr

Notes:
- Costs are $2003
- Capital costs do not include corporate overhead
- IDC is accounted for in discounting of cash flows
- No water rental charges or credits for additional 60 GWh/yr at Revelstoke is included
- Taxes and Grant-in-Lieu and Water Rentals are based on Rated Capacity