BC Hydro
Revenue Requirements
2004/05 and 2005/06

APPLICATION

December 2003

Energy Plan

IMPLEMENTATION

BChydro

Volume I

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2004/05 and 2005/06

BC hydro

Volume 1

Chapter 1.

Application Overview

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1 Introduction

BC Hydro serves more than 1.6 million customers in an area containing over 94 per cent of British Columbia's population. Since its creation 40 years ago it has constructed a secure and economic integrated electric system with over 11,000 megawatts of generating capacity – over 87% of which is based on clean, renewable hydroelectricity. Through the reliable supply of hydroelectricity at some of the lowest rates in the world, BC Hydro supports the economic development of British Columbia in a responsible and environmentally sustainable manner.

In this application BC Hydro seeks a Commission order allowing BC Hydro to increase its domestic rates by 7.23%, effective April 1, 2004, and again by 2.0%, effective April 1, 2005, both on a final basis. BC Hydro also seeks a rate increase of 7.23% effective April 1, 2004 on an interim basis. The specific rates BC Hydro seeks approval to increase are described in appendix B.

This application seeks increases to the rate levels of BC Hydro which, if approved, will remain lower than in almost all jurisdictions in North America[1]. Those rates are necessary to recover prudently incurred costs that will allow BC Hydro to meet the cornerstone objectives of the Energy Plan, and in particular will allow BC Hydro to maintain system reliability; and to responsibly manage environmental and social impacts. At the same time they will allow BC Hydro to maintain and improve service levels in line with customer expectations. Finally, the applied for increases are required to permit BC Hydro an opportunity to earn its allowed rate of return on equity.

BC Hydro also seeks Commission approval for a number of corollary items, including:

- approval of three new deferral accounts, as described in chapter 2; being the Heritage Payment Obligation Deferral Account, the Trade Income Deferral Account, and the BCTC Transition Deferral Account; and
- a reduction in certain wholesale transmission service rates, as described in chapter 6.

BC Hydro does not propose any new rate forms in this application, including stepped rates for industrial and large commercial customers, nor any re-design of any of its current rates,

[1] See appendix D.

including its “E-Plus” rates (Rate Schedules 1105, 1205, 1206 and 1207) and its rates for customers in the non-integrated areas. To make this revenue requirement proceeding as efficient and focused as possible, BC Hydro will deal with Stepped Rates in an application it expects to file in late 2004 or early 2005, and with all other rate design issues in an application it expects to file in early 2005 or at such other time as the Commission believes a dedicated proceeding is appropriate.

2 Context of Application

2.1 Government's Energy Plan

This application is made in the context of significant recent policy developments affecting the electric industry in BC. In particular, the Province developed a new energy policy contained in a document issued November 25, 2002 entitled "Energy for Our Future: A Plan for BC" (the Energy Plan). The Energy Plan was the culmination of an 18-month process, beginning with the election of the new provincial government in May 2001.

The role of BC Hydro was an important consideration in the context of the review. BC Hydro owns 80% of the Province's generating capacity and serves 80% of BC's domestic load. It is the Province's largest Crown corporation. Not surprisingly, BC Hydro followed the process closely and over the past two and a half years has done its best to anticipate key government policies of relevance to it.

The development of the Energy Plan involved the appointment of an Energy Task Force to conduct consultations and set out proposed policies. Early in the discussions that led to the Interim Energy Task Force Report in November 2001, it became apparent that many stakeholders and government officials favoured private industry construction of new generation in preference to BC Hydro constructing new generation. It also became apparent that the development of environmentally responsible energy options was a high priority for government. Although not immediately crystallized, these evolving policies were confirmatory of trends in BC Hydro's own planning, and began to become increasingly reflected in BC Hydro's actions. The Energy Plan confirmed these directions in government thinking and established other fundamental principles to guide the development of future energy policies. Specifically, the four cornerstones of the Energy Plan are as follows:

- continued low electricity rates and public ownership of BC Hydro;
- secure, reliable supply of energy for British Columbia;
- more private sector opportunities in wholesale electricity supply; and
- environmental responsibilities and no nuclear.

These four cornerstones confirm that a number of the initiatives inside B.C. Hydro that were under development were in line with government policy.

In some respects the four cornerstones may conflict and an appropriate balance must be found. For example, a more significant focus on increased reliability or environmental responsibility may put upward pressure on rates. Similarly, short term cost reductions may lead to long term increase in costs. Nevertheless, these four cornerstones of the Energy Plan have determined to a significant extent the manner in which BC Hydro expects to provide service in the future, which in turn has had a direct influence on BC Hydro's anticipated service levels and its expected costs and revenues over the next few years, as articulated below. BC Hydro believes that this method of planning and operating its system minimizes the necessary trade-offs to achieve the four cornerstones.

In addition to the four cornerstones, the Energy Plan prescribes a number of specific policy actions meant to advance the overall direction of the Energy Plan. Some of the policy actions that are particularly germane to this application are set out below.

2.1.1 Heritage Legislation and Government Response to Commission Recommendations

Policy action #1 called for a BCUC-led enquiry into a Heritage Contract, by which the benefits of BC Hydro's existing low-cost generation resources would be preserved for the benefit of BC Hydro's ratepayers through the use of embedded cost rate-making. That enquiry resulted in formal recommendations to government issued by the BCUC on October 17, 2003 (Heritage Recommendations); a government response to the Heritage Recommendations[2] on November 28, 2003; the new *BC Hydro Public Power Legacy and Heritage Contract Act* (the Legacy Act) which received Royal Assent on November 20, 2003; and new regulations regarding BC Hydro which were issued on November 27, 2003. Government's response to the Heritage Recommendations, the Legacy Act and the new regulations inform to a significant extent the cost of energy component of this application.

The Legacy Act prohibits BC Hydro from selling or otherwise disposing of the Heritage Resources and, in addition, its transmission or distribution systems (section 2). One of the new regulations, Heritage Special Directive No. HC1 to BC Hydro (HSD #1), effectively eliminates the Rate Stabilization Account (RSA).

The other new regulation, Heritage Special Direction No. HC2 to the Commission (HSD #2), replaces former Special Direction No. 8 to the Commission regarding the regulation of

[2] See www.gov.bc.ca/em.

BC Hydro. It is similar to Special Direction No. 8, but has some notable features relevant to this application, as follows:

- it requires the Commission to treat for rate-making purposes the Heritage Contract attached to HSD #2 as legally binding, the effect of which is to require BC Hydro to continue to deliver energy at cost based rates;
- it requires the Commission to include in its forecasts of BC Hydro's net income a forecast of Trade Income that may not be greater than $200 million, nor less than zero, thereby ensuring that ratepayers continue to get the full benefit of Trade Income in all but the most exceptional circumstances, and are protected from trading losses; and
- it requires the Commission to allow the establishment of one or more deferral accounts related to the Heritage Contract, the effect of which will be to smooth rates.

2.1.2 Return to Rate Regulation

Policy action #5 confirms that the rate freeze will not be extended again, and that BC Hydro will once again be subject to full rate regulation by the Commission.

2.1.3 Resource Acquisition and Clean Energy

Policy action #13 of the Energy Plan limits BC Hydro's role in the development of new energy supplies to undertaking efficiency improvements and capacity upgrades at existing facilities. Third parties, rather than BC Hydro, are intended to supply all of BC Hydro's incremental energy needs other than Resource Smart projects that increase capacity at BC Hydro's existing facilities for which Cabinet has expressly permitted BC Hydro to seek approval.

Related to the new role for independent power producers, policy action #20 sets a target for BC Hydro and other electric distribution utilities to voluntarily acquire 50% of new supply through clean sources - defined in the Energy Plan as technologies that result in a net environmental improvement relative to existing energy production - subject to such acquisitions having less than a 0.2% per year rate impact.

2.1.4 Contracting out of Services

Policy action #4 confirms that BC Hydro should continue to look for outsourcing opportunities that will reduce costs and maintain or improve service levels.

2.1.5 British Columbia Transmission Corporation

Policy action #15 pronounces government's intention to create a new Crown corporation that will plan, operate and manage BC Hydro's transmission system. The British Columbia Transmission Corporation (BCTC) is the result, and is described further below. Also Special Direction No. 9 (SD #9) to the Commission was approved by Order-in-Council on November 27, 2003. It directs the Commission with respect to the regulation of BCTC.

2.1.6 Line of Business Organizational Structure

Policy action #8 continues BC Hydro's "line of business" management structure, discussed below.

2.1.7 DSM Investments Encouraged

Policy action #23 calls for the amendment of the *Utilities Commission Act* for the purpose of removing a disincentive to invest in demand side management programs. That policy action has been reflected in amendments to section 60 of that statute that permit a utility to earn a return on investments in conservation that is equivalent to the return available for an equivalent investment in generation resources.

2.2 Supply / Demand Balance During Rate Freeze

BC Hydro's last revenue requirement proceeding was almost 10 years ago, when its February 1994 application for a rate increase was denied by the Commission in Order G-89-94. BC Hydro's rates were then frozen by a succession of government enactment, finally ending on March 31, 2003.[3] During this period, BC Hydro's generating capability exceeded domestic demand.

Domestic load growth is shown in Table 1-1.

[3] The Tax and Consumer Rate Freeze Act, as amended, and section 24 of the Miscellaneous Statutes Amendment Act (No. 2), 2001, effectively froze BC Hydro rates from 1996 to March 31, 2003.

Table 1-1. Domestic Sales, F1994 to F2003[4]

(GWh)	F1994	F2003	% Increase
Residential	12,442	15,024	21%
Light Industrial & Commercial	14,086	16,757	19%
Large Industrial	14,178	15,179	7%
Other	1,312	1,717	31%
Total	**42,018**	**48,677**	**16%**
Actual Peak One-hour Demand Integrated System (MW)	**8,059**	**8,481**	**5%**

Notes:
Source is 1994 BC Hydro Annual Report and 2003 BC Hydro Annual Report.

Gross energy requirement to serve domestic load has now grown beyond the capability of the low cost Heritage Resources as shown in Table 1-2:

Table 1-2. Gross Energy Requirements, F1994 to F2003

(GWh)	F1994	F2003	% Increase
Total Domestic Sales	42,018	48,677	16%
Line Losses and System Use	4,315	4,689	
Gross Energy Requirements	**46,333**	**53,366**	**15%**

Notes:
In an average water year, low cost Heritage Resources can provide about 49,000 GWh, which is lower than the gross energy requirements for F2003.

The result is that for the test periods, BC Hydro expects to meet all annual load growth through Power Smart or the acquisition of new resources as opposed to providing supply out of existing unused capability.

BC Hydro's Current Rates

As a result of the rate freeze BC Hydro's rates have not kept pace with inflation, and have been substantially below the increase in the BC Consumer Price Index. Indeed, on a purchasing power basis, BC Hydro's flat rates have decreased by approximately 14% since 1993. BC Hydro's current rates are also low in comparison with the electricity rates of similar utilities in other jurisdictions, being the lowest in North America for commercial and

[4] In this application BC Hydro refers to its fiscal years commencing on April 1, 200X and ending March 31, 200Y, as "F200Y". For example, the current fiscal year commenced on April 1, 2003 and is referred to as "F2004." Further, in tables throughout the document, F2003 Actual = reported results from F2003; F2004 Forecast = year-end forecast for the current fiscal year; and F2005 and F2006 Plan = expenditures or volumes forecast during the test periods.

residential class customers and second only to the rates in Winnipeg for industrial class customers[5].

BC Hydro can no longer keep pace with increasing cost pressures while maintaining and improving service levels and meeting the cornerstone objectives of the Energy Plan. Cost pressures over the last 10 years were offset by trade revenues and reduced financing costs. Additional benefits from these two sources are not expected. The most significant cost pressures over the next two years include:

- an increase in cost of energy as the capacity of low-cost Heritage Resources has been reached. New sources of energy to meet the growth in demand will cost more than the current embedded cost of supply. BC Hydro has adopted competitive procurement through tendering to capture the benefits of a competitive market place on behalf of its customers. BC Hydro's resource procurement strategy puts particular emphasis on ensuring customers have a reliable supply with limited exposure to the volatility of the market.
- an increase in maintenance and capital expenditures due to BC Hydro's ageing assets. These expenditures are being faced by many North American utilities that expanded their systems to meet rapid load growth in the 1960's and 1970's and are necessary if BC Hydro is to sustain and improve its reliability and service levels.
- an increase in pension costs due to BC Hydro's demographic changes and to accounting changes required by GAAP for other post retirement benefits. These new accounting rules require that all forms of post retirement benefit plans be accounted for on an accrual basis. Prior to these new rules, these costs were accounted for on a cash basis.
- an increase in demand side management program spending.
- an increase in costs related to the provision of transmission services.
- an increase in the cost of managing environmental and First Nations related issues. Over the past 10 years, the number of field and office employees dealing exclusively with environmental, social and community issues has increased to meet the rising

[5] See appendix D for a fuller discussion of how BC Hydro's current rates compare to those in other jurisdictions and to the increase in the BC Consumer Price Index. These comparisons are on an after-tax basis.

expectations of various agencies. Thus, this application reflects a cost base that has risen considerably since 1993.

BC Hydro finance charges are also expected to increase due to an increasing interest rate environment and increasing cash flow requirements to finance capital expenditures. BC Hydro has actively managed its debt portfolio to take advantage of the low interest rate environment over the past few years. Interest rates are expected to increase in the coming years from their current historic low levels. BC Hydro is more debt leveraged than most utilities and changes in interest rates will have a significant impact on finance charges.

2.4 Trade Revenues

One of the most important reasons that the rate freeze was sustainable as long as it was has been the rapid and at times dramatic increase in trade revenues from sales to external markets. During this time, gross trade revenues, through the marketing activities of Powerex Corp. (Powerex), increased from $95 million in F1994 to $1,932 million in F2003. Those increasing trade revenues have benefited ratepayers by providing a significant if somewhat volatile offset against BC Hydro's revenue requirement. In the current fiscal year however, BC Hydro forecasts that its net earnings will fall short of its allowed return on equity by about $226 million[6]. Although trade activities will continue to provide value into the future, changing market conditions are likely to reduce expected net trade revenues from the extraordinary levels previously experienced.

2.5 Future Domestic Sales and Load Growth

The Electric Load Forecast: 2003/04 – 2023/24, at appendix F (Load Forecast), is the basis for BC Hydro's investments in its system. New resources and expanded transmission or distribution capabilities are selected to reliably meet the energy and capacity needs identified in the forecast.

Over the two fiscal periods covered by this application, F2005 and F2006, domestic sales are expected to increase as shown in Table 1-3.

[6] As mentioned, the RSA has been eliminated by the issuance of HSD #1 and HSD #2. The remaining balance of $21 million will only partially offset the current year's shortfall.

Table 1-3. Domestic Sales Forecast, F2004 to F2006

(GWh)	F2004 Forecast	F2005 Plan	F2006 Plan
Residential	15,654	15,836	16,063
Light Industrial & Commercial	16,947	17,003	17,202
Large Industrial	14,801	14,734	14,601
Other	1,729	1,714	1,738
Total	**49,131**	**49,287**	**49,604**

Notes:
Source is BC Hydro 2003 Load Forecast (Reference Forecast, Accrued Sales, Probable with Power Smart) and includes firm exports and excludes BC Hydro Own Use.

Over the longer term total domestic sales volumes are projected to increase from 49,131 GWh in F2004 to 54,128 GWh in F2014, for an average annual compound growth rate of approximately 1.0%.

It is important to note that the reference forecast is presented here after allowing for the demand restraining affects of Power Smart. Pursuant to the Energy Plan BC Hydro has an obligation to encourage conservation where it makes economic sense to do so. New supply resources are then acquired to meet the residual load growth.

The cost to customers of failing to supply is very high, and BC Hydro makes every effort to provide adequate resources. Thus, the uncertainty in any forecast is recognized by planning to service load even if reservoir and weather conditions are adverse. Of course, B.C. is fortunate to be part of a robust and very large energy grid. Within the very significant capacity of BC Hydro’s interties with other jurisdictions, energy can be purchased when needed from the United States or Alberta. Nevertheless because of the price volatility of those markets, BC Hydro has planned its resource acquisitions to avoid having to make extra-Provincial market purchases under average water conditions. The cost of supplementing below average water through market purchases is higher than the likely benefit of above average water conditions, and this asymmetry must be considered in planning. The cost of under planning is significant loss or potential dislocation for customers, whereas the risk of a resource surplus can be mitigated by trading surplus energy in the market.

2.6 Reliability

The provision of a secure, reliable supply of electricity to all its customers has been a fundamental part of BC Hydro's mission since its creation. Reliability is one of the cornerstones of the Energy Plan.

To date, BC Hydro has achieved reliability at costs that are lower than most comparable utilities. Each component of the integrated system – distribution, transmission and generation – have reliability concerns and measures that are specific to its particular operation. Together they make up BC Hydro's overall reliability from a customer's perspective. Each part of the business faces its own distinctive challenge.

Distribution faces two primary challenges. First, it must ensure that its energy supply arrangements are sufficiently robust as to ensure adequate supply at a reasonable cost in a range of future circumstances. This challenge is discussed in chapter 4. Second, it must ensure its delivery systems (i.e., wires and substations) and customer care functions are organized and operated to deliver reliable service at a reasonable cost. Specifically, the planning, operation and maintenance of the distribution system must be undertaken in the face of ageing assets.

The overall reliability of BC Hydro's distribution system is currently only 3rd Quartile when compared to North America utilities, and 2nd Quartile when compared to Canadian utilities. Chapter 7 describes the programs in place to manage distribution system performance, including maintenance activities and equipment replacement (to control equipment failures) and vegetation management (to control tree contacts). BC Hydro's large and rugged service territory presents a challenge in terms of limiting the duration of outages. Distribution asset management spending must therefore include consideration of the needs for effective outage response.

Reliability of service is affected by outages on the transmission system when supply to distribution substations and transmission voltage customers is lost. Like distribution, transmission equipment and rights-of-way must be maintained to sustain the viability of the transmission system. Also like the distribution system, capital replacement must compensate for BC Hydro's ageing infrastructure. Transmission additions must be planned to meet growth and changes in the demands on the transmission system. Pursuant to the certain agreements (identified and explained below and in chapter 6), the responsibility to ensure the reliability of this component of BC Hydro's system lies with BCTC.

Generation outages result first in lost economic value and ultimately in a reduced ability to serve, with the exception of remote loads that rely upon the generation system to supplement the transmission system. As discussed in chapter 5, the mechanisms created through the Heritage Contract provide commercial incentives for BC Hydro to maintain and improve the reliability of its Generating units. Some of BC Hydro’s generation equipment is approaching the end of its economic life and will require replacement or refurbishment. The timing and level of spending on maintenance and equipment replacement will be dictated not just by the needs of domestic customers, but also the overall effect of these activities on the opportunities to earn Trade Income.

In summary, all components of BC Hydro's system have performed dependably in the past, despite expenditures that have been relatively low by industry standards. BC Hydro's ability to continue to provide acceptable reliability at below-average cost is threatened by its ageing infrastructure. At all levels of the system, targeted, and balanced decisions have to be made to maintain the quality of service envisaged by the Energy Plan. As has been amply demonstrated by the difficulties encountered in other jurisdictions, the failure to meet these challenges is too expensive to be acceptable.

3 Summary of Revenue Requirement

3.1 Timing of Rate Increase

This section summarizes the revenue requirements of BC Hydro for F2005 and F2006. The summary demonstrates that with its existing rates, BC Hydro will earn far less than its allowed rate of return in each of the fiscal years.

For reasons set out in section 3.3 below, BC Hydro has been unable to file a rate application until now and is unable to change its rates prior to April 1, 2004. At that time, BC Hydro seeks an interim increase in its rates calculated on the basis of its revenue requirement for the test year F2005.

For F2006, BC Hydro's costs will have foreseeably increased. Consequently, BC Hydro seeks an additional adjustment in its rates to become effective April 1, 2005. For certain costs that are foreseeable but cannot be reasonably estimated at this time, BC Hydro seeks establishment of deferral accounts to permit actual costs to be recovered in future rates.

BC Hydro believes that the modest increase sought for F2006 should be considered in this application because the transaction costs associated with a second rate hearing that would have to be absorbed by customers outweigh any benefit a second hearing would introduce. Thus, BC Hydro believes that is worthwhile to establish rates to be effective after April 1, 2005 as part of this proceeding.

3.2 Summary Consolidated Financial Statements

The need for rate increases in the period between F1993 and F2004 was, as noted above, largely offset by the rapid increase in net trade revenues earned by Powerex through the late 1990s and the first few years of this decade. BC Hydro and its ratepayers have also benefited from significant decreases in finance charges since 1993.[7] The downward pressure on rates from these phenomena has largely been exhausted, with smaller trade revenues[8] and flat or increasing interest rates expected. Over the next two test periods

[7] See appendix J.

[8] The definition of trade income adopted as part of the Heritage contract is limited to incremental income resulting from trading actively as opposed to the sale of surplus domestic power. Moreover, forecast market prices are not expected to return to the extraordinary levels or volatility of recent years.

BC Hydro requires the applied-for-rate increases to allow it to meet its domestic service obligations, meet its reliability targets, and afford it an opportunity to earn its allowed return on equity pursuant to HSD #2.

BC Hydro's revenue requirement is the sum of expenditures it needs to incur in each of F2005 and F2006 to meet those service obligations and service level targets, plus its allowed return on equity, less net trade income it anticipates will be earned by Powerex, and less earnings from revenue streams other than domestic rates. That is, the revenue requirement is the sum of money BC Hydro needs to earn from its domestic ratepayers through rates for electricity service established by the Commission. These amounts are shown in Table 1-4.

Table 1-4. Consolidated Revenue Requirement, F2005 to F2006

($ millions)	**F2005 Plan**	**F2006 Plan**
Operations Expense *(Note 1)*	171	129
Maintenance Expense *(Note 1)*	243	140
Administration Expense *(Note 1)*	163	139
Cost of Energy	824	808
Taxes	145	147
Finance Charges	463	497
Depreciation	470	470
Other Expenditures *(Note 1)*	-	178
Total Expenditures:	$2,479	$2,508
plus Return on Equity	427	442
less Net Trade Income	(80)	(89)
less Miscellaneous and Inter-segment Revenues	(185)	(146)
less Other Utilities	(20)	(21)
Total Revenue Requirement	**$2,621**	**$2,694**

Notes:

1. The significant drop in Operations, Maintenance, and Administration expenditures between F2005 and F2006 is a result of not consolidating BCTC's accounts with BC Hydro's after March 31, 2005, when BCTC begins providing service under its own tariff. Other Expenditures reflect payments made to BCTC. See chapter 6 for a further explanation.

Under its current rate structure BC Hydro anticipates it would earn the following revenues from its domestic ratepayers, as shown in Table 1-5:

Table 1-5. Domestic Ratepayer Revenues, F2005 to F2006 (F2004 Rates)

($ millions)	**F2005**	**F2006**
Domestic Ratepayer Revenues	$ 2,444	$ 2,463

The differences between BC Hydro's revenue requirement and its expected domestic revenues under its current rate structure in each of F2005 and F2006 ($177 million and $231 million, respectively) are the amounts that need to be made up by the applied-for rate increase. In particular, BC Hydro anticipates that if granted its applied-for rate increases its domestic tariff revenues for each of F2005 and F2006 will be $2,621 million and $2,694 million, equal to its revenue requirement in each of the two test periods.

3.3 Principal Cost Drivers Related to the Test Year Revenue Requirements

Relative to F1994, the principal drivers causing the revenue that must be recovered from domestic ratepayers are:

- Increased cost of energy;
- Increased costs to maintain reliability of the system;
- Increased pension costs;
- Increased finance costs;
- Increased investment in Power Smart;
- Increased costs to be incurred as a result of the creation of BCTC; and
- Increased costs relating to management of environmental and First Nation related issues.

Each of these cost drivers is discussed in the chapters that follow with an emphasis on those within BC Hydro's control. These cost drivers did not come into existence overnight. However, their accumulating effect has been obscured in the last few years by the abnormal market conditions that gave rise to extraordinary trade income. Low projected net income in F2004 and the rapid depletion of the RSA in the previous two years highlights a clear conclusion: BC Hydro's current rates are not just and reasonable because they do not allow it an opportunity to earn a just and reasonable return on its investment. Rates should be increased now. BC Hydro has not applied for an increase in its rates earlier only because it was unable to file for rate relief until the government response to the Heritage Recommendations was known and it cannot apply new rates until the new customer billing system is in place and fully functioning. As such, the rate increase can only be applied starting April 1, 2004.

4 Overview of BC Hydro Organizational Structure

This section describes BC Hydro's organizational structure, for the primary purpose of describing the basis of the forecasts in this application. Significant changes to that structure since 1994, and the focus of this section, include:

- the implementation of a "line of business" internal management structure;
- the creation of BCTC and the transfer to it of certain operating and planning responsibilities; and
- BC Hydro agreements with Accenture Business Services of British Columbia (ABS) for the purpose of outsourcing certain back-office functions to the private sector.

In addition, this section includes a short description of BC Hydro's subsidiaries and their functions within BC Hydro.

4.1 Line of Business Management Model

In April 2002 BC Hydro implemented a change to a "line of business" management model. The new structure is largely in place at the time of this application and is a specific policy action of the Energy Plan. The current management structure is depicted in the organization chart found in schedule 1-1. The focal points of the new management structure are the new generation and distribution lines of business. These lines of business are at the centre of the new structure because of their fundamental importance to BC Hydro's ultimate purpose, being the provision of reliable, low-cost electricity to its customers.

BC Hydro's thinking with respect to the role of the lines of business under a corporate umbrella was refined and presented in its Heritage Contract proposal. The application of the line of business model will not be allowed to detract from BC Hydro's mandate of maximizing the value of its system and the provincial resources which that system utilizes to deliver low-cost reliable energy for the benefit of all BC Hydro stakeholders. Thus, BC Hydro as a corporation will determine its strategic objectives and each line of business will be charged with achieving those corporate objectives that fall within its mandate. 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.

BC Hydro has also created a number of new internal service organizations. The function of the service organizations is to support the lines of business, and in some cases each other, by providing required services, on a cost-effective basis. The service organizations described in this application are Engineering Services, Field Services and the Materials Management Business Unit.

In addition to the corporate office's responsibility for providing corporate-wide decision-making on a wide-range of issues, the corporate office also provides services to the lines of business.

Consistent with the line of business model, BC Hydro has recently contracted with ABS to provide certain back-office services to BC Hydro, BCTC and BC Hydro's subsidiaries. These services were all previously provided in-house. The ABS transaction and its role in this revenue requirement application are described further below.

Under the line of business management structure each line of business and each service organization is meant to operate so as to maximize the value of BC Hydro's business as a whole while providing clear accountability for the proper functioning of each component of the business. For the lines of business, this means determining their service obligations for the ensuing period or periods, and developing plans and budgets sufficient to meet those obligations, including the procurement of services from internal service organizations and ABS. For the service organizations this means treating the lines of business as if they were clients, and developing plans and budgets for the ensuing period or periods sufficient to meet the needs of the lines of business and BCTC. For the corporate office this means leadership, coordination, approval and support of the line of business plans through common corporate functions such as finance, regulatory, human resources and legal services.

The line of business management structure is reflected in the organization and presentation of information in this application. Thus, the bulk of the application, chapters 3 to 9, describes the activities of the lines of business and the service organizations in the test period, and the anticipated costs of those activities. For example, chapter 7, "Electricity

Distribution and Non-Integrated Areas", describes what BC Hydro Distribution sees as its distribution service obligations in the ensuing test periods, and the expenditures it expects it will incur in order to meet those service obligations, including expenditures in respect of services provided by the internal service organizations and an allocation of corporate costs. By contrast, the Engineering Services section of chapter 9 is focused not on the level of services it expects to provide in the ensuing test periods – that is covered in the line of business sections – but instead focuses on how Engineering Services intends to provide those required services in a way that maximizes value.

Chapter 2 sets out and discusses the forecast consolidated financial statements of BC Hydro for the test periods, and also provides a reconciliation between the consolidated financial statements and the following chapters that describe the costs of the lines of business and service organizations. The consolidated financial statements include BCTC for F2005.

4.2 British Columbia Transmission Corporation

On July 24, 2003, the Transmission Corporation Act (BCTC Act) was brought into force, thereby creating the framework for BCTC, one of the newest B.C. Crown Corporations. The creation of BCTC is a key element of the Energy Plan.

The BCTC Act:

- confirms that BCTC shall be a Crown-owned corporation whose shares may not be sold or otherwise disposed of by government;
- provides that agreements between BC Hydro and BCTC that allocate between them the roles and responsibilities that were previously fulfilled by BC Hydro are authorized, valid, and beyond the scope of the Commission's jurisdiction to prohibit; and
- confirms that the Commission is to have its usual full range of authority to regulate the rates and services of both BCTC and BC Hydro.

On November 20, 2003 a number of agreements between BC Hydro and BCTC were designated by the Lieutenant Governor in Council under sub-section 3(1) of the BCTC Act (BCTC Designated Agreements). The Designated Agreements are more fully described in chapter 6 and are produced in their entirety at www.bcuc.com.

With some minor exceptions, none of the agreements necessary to implement the BCTC transaction provide for the sale of BC Hydro's transmission assets to BCTC. The Legacy Act, section 2, prohibits BC Hydro from selling or otherwise disposing of its transmission system, as well as the Heritage Resources and its distribution system, with some necessary exceptions. The creation of BCTC is consistent with policy action #3 of the Energy Plan, which calls for continued public ownership of BC Hydro's generation, distribution and transmission assets.

Pursuant to the BCTC Designated Agreements and consistent with the Energy Plan, in the short term BCTC will provide transmission services through BC Hydro, and under BC Hydro's existing WTS tariffs, until April 1, 2005. This initial period is referred to in the application as "phase 1". During phase 1 the entire transmission revenue requirement is intended to be recovered through BC Hydro's existing WTS tariffs.

BC Hydro and BCTC expect that BCTC's tariffs will be approved on or about April 1, 2005 thus commencing "phase 2". During phase 2 and described in chapter 6, section 11, rates for WTS will be designed by BCTC to recover the BCTC components of the transmission revenue requirement and the BC Hydro components of the transmission revenue requirement.

This application, and in particular the rate increase BC Hydro seeks for F2006, is based on the assumption that BC Hydro's net WTS cost forecast will remain unchanged between phase 1 and phase 2. If the assumption is correct there will be no impact on BC Hydro's revenue requirement for F2006, and no need to adjust the rates approved for the period commencing April 1, 2005. To the extent the assumption is incorrect, and changes to BC Hydro's net WTS costs cause a change in its F2006 revenue requirement, BC Hydro proposes to carry forward such changes, whether positive or negative. The BCTC Transition Deferral Account, described in chapter 2, is the mechanism BC Hydro proposes to use for this purpose. Again, no adjustment would be necessary to the rates approved for the period commencing April 1, 2005.

4.3 Accenture Business Services

As noted above, policy action #4 of the Energy Plan provides for BC Hydro to contract out certain non-core functions for the purposes of maximizing flexibility, focus, and cost-effectiveness. Consistent with that direction, BC Hydro has entered into a set of agreements with ABS under which it provides services to BC Hydro that were formerly done by BC Hydro itself. ABS provides service to BC Hydro, BCTC, and BC Hydro subsidiaries pursuant to service agreements. The levels of service are determined by the business units, while the costs for such services are determined through the agreements. These agreements provide for prescribed savings from those costs BC Hydro forecasts it would have incurred to maintain the service at historical levels. This application presents and describes the cost of the ABS contracts both as line item costs in the line of business and service organization forecasts, and in an aggregated manner (chapter 9).

4.4 Subsidiaries

BC Hydro has two subsidiaries, Powerex and Powertech Labs Inc.[9], which have an impact on the revenue requirements in the two test periods. The former is a leading power marketer in western Canada and the western United States. The latter is a research and engineering technology services company. Neither are public utilities within the meaning of the Utilities Commission Act, and neither are directly involved in the provision of electricity to BC Hydro's ratepayers. Their anticipated net revenues are consolidated with BC Hydro's for rate-making purposes pursuant to HSD #2, and have the effect of making BC Hydro's revenue requirements lower in each of the two test periods than they otherwise would be.[10]

4.5 Managing a Disaggregated Structure

BC Hydro believes that the various restructuring initiatives described in the preceding sections will result in focussed, efficient organizations all operating within the heart of their core competencies. Nevertheless, BC Hydro is aware of the need to ensure that disaggregation does not lead to a loss of coordination in the overall operation of the electric system in B.C. or diminish service levels to its customers.

Each aspect of the restructuring is designed to encourage full coordination between all the entities that participate in providing power to the end user. Within BC Hydro, the lines of

---

[9] BC Hydro has other subsidiaries created for specific projects such as Vancouver Island Generation Project which are immaterial to this application.

[10] Pursuant to paragraph 6 and the definition of "Trade Income" in HSD #2, the Commission is obliged to include in its calculation of BC Hydro's revenue requirement an amount equal to a forecast of Powerex's Trade Income, up to $200 million and not less than zero. Powerex's forecasts of its Trade Income in F2005 and F2006 are $80 million and $89 million respectively – see chapter 9 for more detail.

business and service organizations reward their management based on BC Hydro's overall success in meeting its obligations. As fully explained in BC Hydro's proposal to the Heritage Contract proceeding, full coordination with BC Hydro and between BC Hydro and its subsidiaries, as exemplified by Powerex, is a day-to-day necessity and focus.

In its arrangements with ABS, BC Hydro has retained the ability to set the standard that must be achieved and has structured the relationship so that specific accountable BC Hydro employees will be responsible for ensuring that clear directions are given to ABS and its performance carefully monitored. The means of accomplishing this is described in section 8.4 of chapter 9.

The BCTC Designated Agreements provide BC Hydro and BCTC with the opportunity to work together to ensure that the level of service provided to customers is seamless and continues to achieve the reliability standard that BC Hydro's customers have come to expect. BCTC is an independent entity. BC Hydro as owner of the wires and as BCTC's biggest customer, will work with BCTC to ensure that the needs of all BC Hydro's customers continue to be met reliably and efficiently. Where BC Hydro and BCTC identify alternative options for the future, the BCUC will be available to ensure that the appropriate solutions are developed for the ratepayer. The initial and most expensive steps in the large restructuring BC Hydro has undertaken will be complete in F2004. These steps have had no effect on rates. Looking ahead, implementation of these diverse arrangements with BCTC and ABS, as new participants within the electric industry in B.C, and the development of the line of business structure within BC Hydro itself, are important and challenging initiatives. The increasingly efficient organizations that result, each operating within their areas of core expertise, should ensure that BC Hydro's customers continue to receive low cost, reliable service in the years ahead. However, delivering on the potential of these structures will require ongoing discipline and management. For that reason, BC Hydro sees the near future covered by the test period to be a time for implementing the initiatives already begun, not undertaking significant new ones. The focus of management during this transitional period will be on monitoring progress and ensuring effective interaction of the various new structures identified in this application. To the extent BC Hydro's new structures are not meeting the objectives identified in this application, BC Hydro will amend the structures to ensure that the value of the electric system that has been developed by BC Hydro is not compromised. In that way, BC Hydro's customers will be assured that there is no interruption to the high quality reliable electric service they have come to expect.

5 Conclusion

This application seeks increases to the rate levels of BC Hydro which, if approved, will remain lower than in almost all jurisdictions in North America. Those rates are necessary to recover prudently incurred costs that will allow BC Hydro to meet the Energy Plan, and in particular will allow BC Hydro to maintain system reliability and to responsibly manage environmental and social impacts. At the same time they will allow BC Hydro to maintain and improve service levels. For these reasons BC Hydro respectfully submits that the rates it proposes to charge based on F2005 and F2006 test years are just and reasonable, and that the Commission ought to approve them pursuant to sections 58 and 60 of the *Utilities Commission Act*.

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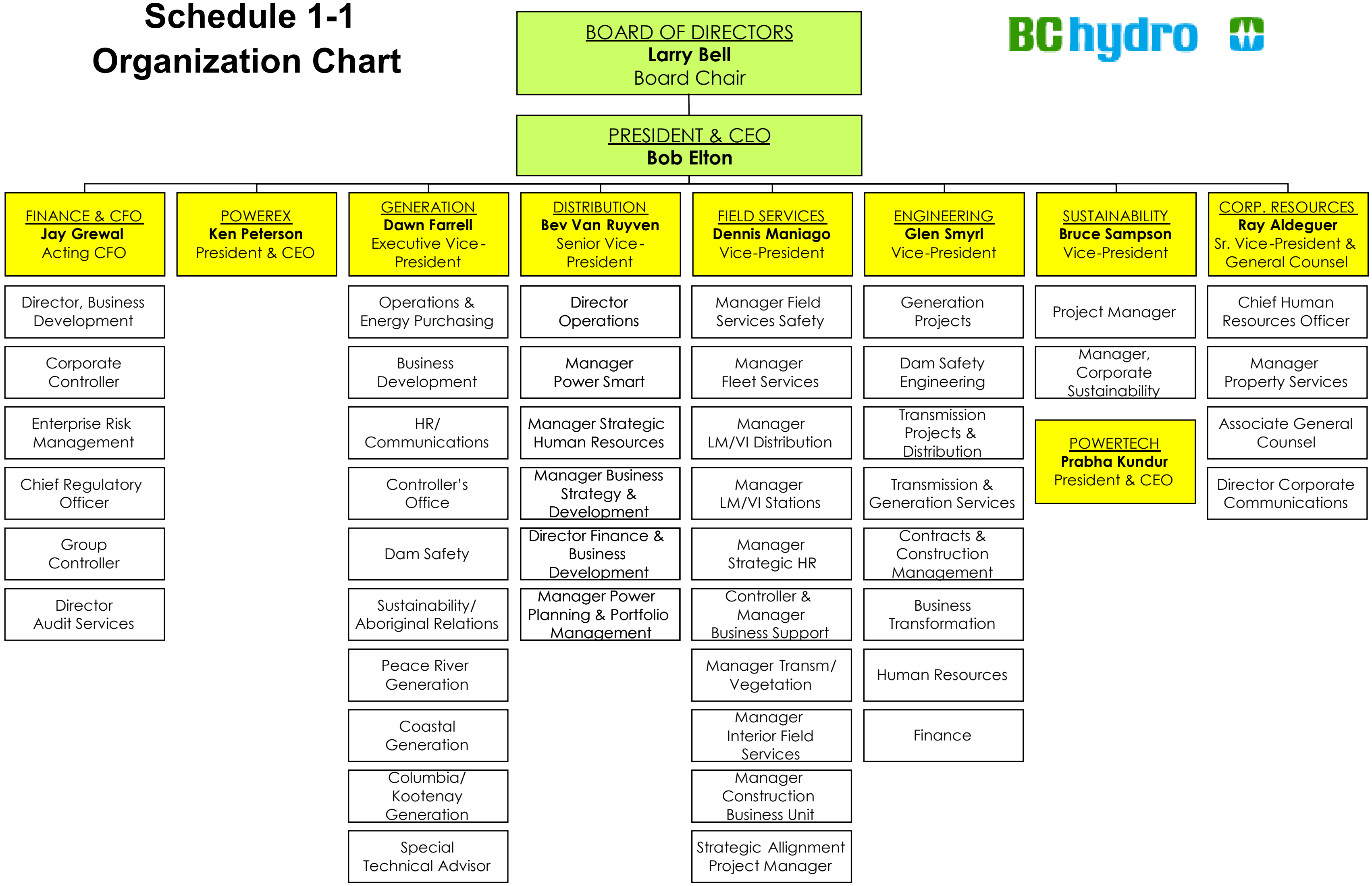
Schedule 1-1
Organization Chart



Senior Executive & Direct Reports

Revenue Requirement Application

2004/05 and 2005/06

BC hydro

Volume 1

Chapter 2.

Consolidated Revenue Requirements and Financial Schedules

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1 Introduction

This chapter of the application provides:

- BC Hydro's forecasts of revenues and costs in the test periods, both with and without the applied-for rate increases, on a consolidated basis (section 2);
- summary explanations of the variances between consolidated cost and revenue items from year to year (section 3);
- a description of the deferral accounts BC Hydro seeks approval for in this application (section 4);
- reconciliations between the consolidated costs and revenue forecasts as described in sections 2 and 3, and the forecasts of costs and revenues of the lines of business and service organizations described in chapters 3 to 9 (sections 5 and 6); and
- a description of the methodology employed by BC Hydro to allocate corporate costs to the lines of business, service organizations, and subsidiaries (section 7).

2 Pro Forma Consolidated Statements

Table 2-1 is a summarized pro forma statement of operations of BC Hydro assuming electricity rates remain unchanged.

Table 2-1. Pro forma Statement of Operations, No Rate Increase

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Equity	**$2,700**	**$2,726**	**$3,042**	**$3,120**
Domestic				
Revenues	2,475	2,516	2,525	2,539
Inter-segment revenues	6	76	124	91
Expenses	(2,267)	(2,537)	(2,478)	(2,498)
	214	**55**	**171**	**132**
Trade Income	138	91	80	89
Transfer from RSA *(Note 1)*	66	21		
Net Income	**$418**	**$167**	**$251**	**$221**
Rate of return on equity	15.47%	6.13%	8.25%	7.08%
Allowed rate of return on equity	15.47%	14.33%	13.91%	13.91%
Required rate increase (%)	N/A	N/A	7.23%	2.00%

Notes:
1. It is anticipated that the RSA balance will be nil at the end of F2004.

BC Hydro's allowed rate of return on equity for the test periods F2005 and F2006 is calculated pursuant to HSD #2 in chapter 10 of this application. As can be seen from Table 2-1, BC Hydro expects to significantly under-earn in each of F2004 through F2006 under its current rates. The revenue shortfalls for F2005 and F2006 are forecast to be $177 million and $231 million respectively.

Table 2-2 shows the detailed pro forma consolidated statement of operations with tariff rates unchanged and Table 2-3 shows the same statement with rates increased by the proposed rate increases of 7.23% and 2.00%. As can be noted, the impact of the rate increases would be to increase domestic revenues and decrease finance charges. Energy costs and taxes would also be increased as the water rental rate and some grants in lieu of taxes are indexed to electricity rates. This indexing is discussed further in sections 3.4.2. and 3.8.2.

1 **Table 2-2. Pro forma Consolidated Statement of Operations with Rates Unchanged**

For the Years Ended March 31 ($ millions)	A F2003 Actual	B F2004 Forecast	C F2005 Plan	D F2006 Plan
REVENUES				
Domestic				
Residential	$ 923	$ 959	$ 971	$ 985
Light industrial and commercial	893	901	904	914
Large industrial	516	503	502	496
Other energy sales	88	86	87	89
Miscellaneous	55	67	61	55
	2,475	2,516	2,525	2,539
Intersegment revenues	6	76	124	91
	2,481	2,592	2,649	2,630
EXPENSES				
Domestic cost of energy	708	944	819	788
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	169	171	129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Depreciation and amortization	414	428	470	470
Taxes	145	142	145	147
	1,773	2,072	2,011	1,991
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	520	638	639
Finance charges	457	454	467	507
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	66	171	132
Restructuring Costs	37	11	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	55	171	132
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	**$ 280**	**$ 76**	**$ 171**	**$ 132**
TRADE INCOME	**138**	**91**	**80**	**89**
TOTAL NET INCOME	**$ 418**	**$ 167**	**$ 251**	**$ 221**
PAYMENT TO THE PROVINCE	$ 338	$ 128	$ 195	$ 156
ACTUAL RETURN ON EQUITY	15.47%	6.13%	8.25%	7.08%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.91%
BALANCE IN RSA	$ 21	$ -	$ -	$ -
RATE INCREASE	0.00%	0.00%	0.00%	0.00%
CUMULATIVE RATE INCREASE	0.00%	0.00%	0.00%	0.00%

Table 2-3. Pro forma Consolidated Statement of Operations with Proposed Rate Increases

For the Years Ended March 31 ($ millions)	A F2003 Actual	B F2004 Forecast	C F2005 Plan	D F2006 Plan
REVENUES				
Domestic				
Residential	$ 923	$ 959	$ 1,041	$ 1,077
Light industrial and commercial	893	901	970	1,000
Large industrial	516	503	539	543
Other energy sales	88	86	91	95
Miscellaneous	55	67	61	55
	2,475	2,516	2,702	2,770
Intersegment revenues	6	76	124	91
	2,481	2,592	2,826	2,861
EXPENSES				
Domestic cost of energy	708	944	824	808
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	169	171	129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Depreciation and amortization	414	428	470	470
Taxes	145	142	145	147
	1,773	2,072	2,016	2,011
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	520	810	850
Finance charges	457	454	463	497
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	66	347	353
Restructuring Costs	37	11	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	55	347	353
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	**$ 280**	**$ 76**	**$ 347**	**$ 353**
TRADE INCOME	**138**	**91**	**80**	**89**
TOTAL NET INCOME	**$ 418**	**$ 167**	**$ 427**	**$ 442**
PAYMENT TO THE PROVINCE	$ 338	$ 128	$ 344	$ 344
ACTUAL RETURN ON EQUITY	15.47%	6.13%	13.91%	13.91%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.91%
BALANCE IN RSA	$ 21	$ -	$ -	$ -
RATE INCREASE	0.00%	0.00%	7.23%	2.00%
CUMULATIVE RATE INCREASE	0.00%	0.00%	7.23%	9.37%

3 Discussion of Financial Forecasts

3.1 BC Hydro Equity

HSD #2 defines BC Hydro's equity, for rate-making purposes, as the following:

> "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; and
>
> (d) contributions in aid of construction.

Actual equity for F2003, and forecast equity for F2004 to F2006, is shown in Table 2-4. The following table shows the components of equity in those periods.

Table 2-4. Equity for Rate Making Purposes

($ millions)	**F2003 Actual**	**F2004 Forecast**	**F2005 Plan**	**F2006 Plan**
Retained earnings at beginning of year	$1,529	$1,609	$1,648	$1,964
Net income	418	167	427	442
Payment to the province	(338)	(128)	(344)	(344)
Asset retirement obligation adjustment *(Note 1)*	-	-	233	-
Special dividend to the province for BCTC *(Note 2)*	-	-	-	(20)
Retained Earnings at End of Year	**$1,609**	**$1,648**	**$1,964**	**$2,042**
Deferred revenue	258	276	296	320
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	609	625	643
Rate Stabilization Account	21	-	-	-
Equity	**$2,700**	**$2,726**	**$3,069**	**$3,180**
Allowed rate of return on equity	15.47%	14.33%	13.91%	13.91%
Allowed return on equity	**$418**	**$391**	**$427**	**$442**

Notes:
1. This adjustment is explained in section 3.7.3.
2. The special dividend to the province was paid in F2004. It is shown in F2006 because BCTC is consolidated with BC Hydro in F2004 and F2005.

3.2 Domestic Revenues

Domestic revenues are the proceeds from sales of electricity to customers within the province and proceeds from sales of electricity at the border to certain customers outside of the province under treaty or long-term contracts with BC Hydro (mainly Skagit Valley Treaty commitment and Hyder, Alaska).

Domestic revenues have been determined using the applied-for rates and forecast sales volumes for major rate classes. Table 2-5 and Table 2-6 show breakdowns of domestic revenues and sales volumes, respectively, by those rate classes. More detailed revenue schedules are included at the end of this chapter.

Table 2-5. Domestic Revenues (with applied for rate increases)

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Residential	$923	$959	$1,041	$1,077
Light industrial and commercial	893	901	970	1,000
Large industrial	516	503	539	543
Other				
Irrigation	3	3	3	3
Street lighting	23	23	24	24
City of New Westminster	14	13	15	16
Aquila Networks Canada	26	27	29	31
Total Revenue Requirement	**$2,398**	**$2,429**	**$2,621**	**$2,694**
Other utilities *(Note 1)*	22	20	20	21
Miscellaneous	55	67	61	55
Total	**$2,475**	**$2,516**	**$2,702**	**$2,770**

Notes:
1. Other utilities under long-term contracts.

Table 2-6. Domestic Sales

(GWh)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Residential	15,024	15,654	15,836	16,063
Light industrial and commercial	16,757	16,947	17,003	17,202
Large industrial	15,179	14,801	14,734	14,601
Other				
Irrigation	84	88	89	90
Street lighting	219	218	221	224
City of New Westminster	423	401	402	403
Aquila Networks Canada	673	708	688	707
Other utilities	318	314	314	314
Total	**48,677**	**49,131**	**49,287**	**49,604**

Table 2-7 identifies the average rates by customer class, before and after the proposed rate increases.

Table 2-7. Average Rates, Before and After Proposed Increases

Customer Class ($ per MWh)	Current Rates	F2005	F2006
Residential	61.3	65.7	67.0
Light industrial and commercial	53.2	57.0	58.2
Large industrial	34.0	36.5	37.2

3.3 Inter-Segment Revenues

In accordance with HSD #2 and the definition of Trade Income within it, the pro forma statements of operations presented in this application identify Trade Income as a distinct line item. Trade Income is Powerex's net income, adjusted for rate-making purposes if necessary to be no more than $200 million and no less than $0.00. It includes Powerex's revenues and costs arising from transactions with BC Hydro. Inter-segment revenues reflect the BC Hydro side of such transactions. For example, a sale of energy by BC Hydro to Powerex is a cost item in the calculation of Trade Income. The revenue side to BC Hydro from that sale is included in inter-segment revenues.

Table 2-8 identifies specific elements identified as Inter-segment revenues in the pro forma consolidated statements of operations.

Table 2-8. Inter-Segment Revenues, F2003 to F2006

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Net sales to Powerex - Future Use *(Note 1)*	–	$3	$50	$24
Point-to-point wheeling charge to Powerex *(Note 2)*	–	49	60	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)*	6	10	–	–
Total Inter-segment Revenues	**$6**	**$76**	**$124**	**$91**

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.

3.4 Domestic Cost of Energy

The "domestic cost of energy" shown on the pro forma consolidated statements of operations is composed of the following items:

- water rental costs;
- purchases from IPPs and other long-term purchase commitments;
- other energy purchases (short-term);
- natural gas purchases for thermal generation and re-marketing;
- transmission charges and other expenses; and
- energy costs arising from the provision of services in the non-integrated areas.

3.4.1 Summary

Table 2-9 summarizes the domestic cost of energy forecast for the test periods. More details are provided in schedule B1, which shows that the domestic cost of energy is the sum of the cost of energy component from generation (Heritage Contract) (chapter 5), energy supply less Heritage Payment Obligation (chapter 4), transmission (chapter 6), and Non-Integrated Areas (chapter 7).

Table 2-9. Domestic Cost of Energy, F2003 to F2006

	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Domestic cost of energy ($ millions)	$708	$944	$824	$808
Change from prior year – increase (decrease)		236	(120)	(16)
Domestic sales volumes (GWh)	48,677	49,131	49,287	49,604
Domestic energy unit cost ($/MWh)	$14.5	$19.2	$16.7	$16.3
Variance ($ millions):				
increase (decrease) in unit cost			(123)	(21)
increase in volume			3	5
			$(120)	**$(16)**

3.4.2 F2005 Compared to F2004

Domestic cost of energy is forecast to decline in F2005 from F2004 largely due to the impact of water inflows. F2005 assumes normal inflow levels compared to the below normal levels experienced in F2004. This allows for an increase in low cost hydro generation. Hydro generation is expected to increase by approximately 1,400 GWh in F2005 over F2004 levels.

As mentioned in section 2, the proposed rate increase will increase the water rental fees, which are indexed to BC Hydro's electricity rates. Water rental rates increase in January of each year, following a rate increase. For example, an electricity rate increase on April 1, 2004 will increase water rental rates effective January 1, 2005. Water rental charges are projected to increase in F2005 by $5 million due to the proposed rate increase in F2005.

3.4.3 F2006 Compared to F2005

The forecast small decrease in domestic cost of energy in F2006 from F2005 is largely due to the expected decline in the average cost of market purchases under the Heritage

Contract. This is partly offset by the effect of the proposed rate increase on water rental charges.

3.5 Operations, Maintenance, and Administration Costs

BC Hydro has recently initiated a change in its internal financial reporting, moving away from reporting on the basis of aggregated operations, maintenance, and administration costs (OMA), and instead moving to reporting those costs on a disaggregated basis. BC Hydro believes this will allow a sharper focus in the budgeting and planning process, make more transparent the manner in which the objectives of the organization are to be realized, and enhance the ability of BC Hydro to see if objectives have been achieved. This is a very recent initiative and the functional costs reported in chapters 3 to 9 have not, with some exceptions, been disaggregated in this manner. Table 2-10 presents OMA consolidated across BC Hydro but on a disaggregated basis. BC Hydro will be able to provide the OMA disaggregation at the cost of service level by function (‘C’ schedules) by mid-January 2004.

Table 2-10. Disaggregated OMA, F2003 to F2006

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan *(Note 1)*
Operations expense	$143	$169	$171	$129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Total OMA	**$506**	**$558**	**$577**	**$408**

Notes:
1. F2006 does not include OMA for BCTC.

3.5.1 F2005 Increase over F2004

The OMA increase in plan F2005 over forecast F2004 is due in part to the following:

- Increased net maintenance costs of $14 million to maintain existing reliability levels. The increased maintenance costs are necessary due to the ageing of assets. An increase of $21 million is budgeted in F2005 but due to an unanticipated $7 million expense incurred in F2004 for system restoration and maintenance costs required as a result of forest fires there is a net increase of $14 million.
- An increase in incremental ongoing costs of $5 million associated with the establishment of corporate functions within BCTC. See discussion at chapter 6.

- Increased funding of $7 million for strategic research and development programs. See discussion at chapter 3.
- The increases are offset by a net decrease of $6 million in information system related costs.

3.5.2 F2006 Decrease from F2005

The OMA decrease in plan F2006 from plan F2005 is primarily due to the following:

- Beginning in F2006, the costs of BCTC are no longer consolidated with BC Hydro. BCTC charges wheeling costs and a service fee to BC Hydro. The wheeling charge and the service fee are not included in BC Hydro's F2006 OMA costs. This change results in a reduction of OMA costs of $163 million. This reduction is expected to be fully reflected in increased payments to BCTC in F2006 as described in chapter 6.
- Net administrative costs reductions of $6 million including cost savings of $5 million arising from the purchase of ABS services.

3.6 Finance Charges

3.6.1 Background

As with most utility companies, BC Hydro is financed to a large extent by debt. BC Hydro's long-term debt is comprised of bonds, notes and debentures, with all debt issued with a maturity of five years or longer having annual sinking fund requirements. BC Hydro also has revolving borrowings obtained under agreement with the province. BC Hydro's debt is either held or guaranteed by the province.

BC Hydro also uses derivative financial instruments, principally interest rate and foreign currency swaps, options and forward rate agreements, to manage interest rate and foreign exchange risks related to debt.

Good performance in the management of the debt portfolio is measured through benchmarking against internal targets and other Government-owned and debt-guaranteed, integrated electric utilities. Internal targets are designed to incorporate operational aspects of BC Hydro's business as well as economic aspects, rather than the alternative where the debt portfolio is managed in isolation of the underlying business. This approach to debt management is a best practice in the industry.

Relative to other government-owned and debt-guaranteed integrated electric utilities, BC Hydro is at or above average in most debt-related statistical measures. For example, BC Hydro's cash flow to adjusted total debt ratio is equal to the group average, both with a ratio of $0.09 per dollar of debt. BC Hydro's average coupon rate of 6.8% is well below the peer-group average of 7.93%, even after accounting for differences in credit rating.

In the process of forecasting finance charges, BC Hydro employs a number of economic assumptions as inputs, primarily short and long term interest rates in both Canada and the US, along with the Canada/US exchange rate. These economic assumptions are developed and provided to BC Hydro by the Treasury Board of the Province of BC. This methodology has a number of benefits, the most important being a common set of economic assumptions across all crown corporations and the government itself in forecasting net provincial income. Table 2-11 identifies the interest rate assumptions used in the test periods.

Table 2-11. Interest Rate Forecast, F2004 to F2006

(Note 1)	**F2004 Forecast**	**F2005 Forecast**	**F2006 Forecast**
Canadian Short-term Interest Rates	3.15%	3.63%	5.06%
U.S. Short-term Interest Rates	1.26%	2.00%	4.00%
Canadian Long-term Interest Rates	5.45%	5.91%	6.64%
U.S. Long-term Interest Rates	5.06%	5.78%	6.54%
USD/CAD FX Rate	0.7324	0.7490	0.7500

Notes:
1. Provincial Government Forecast, August 2003, for F2004 to F2007.

3.6.2 Bond Ratings

BC Hydro is a crown corporation that utilizes the province as its fiscal agent for all borrowing activity. As a result, BC Hydro’s credit rating is not based solely on its own financial soundness but also includes the impact of the provincial guarantee. This leads to similar ratings for both BC Hydro and the province by all rating agencies. In addition, the major bond rating agencies consider BC Hydro’s financial condition and trend as an important part of their review of the province , and this is reflected in the ratings that they assign the province.

The province currently holds a Aa2 long-term debt rating from Moody's, AA- from Standard and Poor's, and an AAlow from Canada's Dominion Bond Rating Service (all agencies have their own scales).

Table 2-12 identifies Finance Charges during the test periods.

Table 2-12. Finance Charges, F2003 to F2006

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Interest on debt securities				
Bonds, notes and debentures	$ 536	$ 510	$ 505	$ 540
Revolving borrowings	5	16	22	21
Amortization of deferred debt costs and other expenses *(Note 1)*	26	28	30	33
	567	**554**	**557**	**594**
Less:				
Sinking fund income	(60)	(62)	(58)	(52)
Other income *(Note 2)*	(26)	(18)	(11)	(4)
Finance charges capitalized to unfinished construction	(24)	(20)	(25)	(41)
	(110)	**(100)**	**(94)**	**(97)**
Total Finance Charges	**$ 457**	**$ 454**	**$ 463**	**$ 497**

Notes:

1. As per Order G-47-02. See discussion in section 3.6.3.
2. Other income largely relates to gains on interest rate and cross currency swaps.

3.6.3 Foreign Currency Translation

Foreign currency-denominated revenues and expenses are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Foreign currency-denominated monetary assets and liabilities are translated into Canadian dollars at the rate of exchange prevailing at the balance sheet date.

Gains and losses arising from the translation of foreign denominated long-term monetary items are deferred and amortized . On July 11, 2002, the Commission approved, under Order G–47–02, the continued deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pooled method of amortization, to be applied on a prospective basis for the fiscal year beginning April 1, 2002.

For long-term debt, the straight-line pooled method is based on the weighted average remaining term to maturity of the long-term foreign currency-denominated debt portfolio. Where foreign currency-denominated long-term debt is refinanced in the same currency, any unamortized foreign currency translation gains and losses associated with the refinanced debt continue to be deferred and amortized. Where a portion of the foreign currency denominated long-term debt is refinanced in a different currency, a pro rata portion of the related pool of any unamortized foreign currency translation gains or losses are included in finance charges at the refinancing date.

For sinking funds, the straight-line pooled method is based on the weighted average term to maturity of the underlying long-term foreign currency-denominated debt weighted by its sinking fund balances.

3.6.4 F2005 compared to F2004

Finance charges are expected to be similar in these years. An expected decrease in interest charges on long-term debt due to the refinancing of maturing long-term debt at lower rates is offset by an expected increase in the average volume of debt.

3.6.5 F2006 compared to F2005

Finance charges are expected to increase in F2006 largely due to the projected increase in both US and Canadian interest rates. Projected refinancings of Canadian revolving borrowings and a US floating debt issue with Canadian long-term debt also contribute to the increase in finance charges.

3.7 Depreciation and Amortization

Depreciation and amortization (Depreciation) is the allocation of the cost of capital assets and deferred assets over their estimated service lives. Assets are depreciated on a straight-line basis with the exception of vehicles, which are depreciated on a declining balance basis. Capital assets in service are depreciated on an individual or a pooled basis.

Depreciation includes the following components:

- depreciation of capital assets in service;
- amortization of contributions arising from the Columbia River Treaty and contributions in aid of construction;
- amortization of studies and abandoned or indefinitely deferred projects;
- amortization of deferred Aboriginal negotiation and settlement costs;
- amortization of demand-side management programs and the cost of an interest free loan to Howe Sound Pulp and Paper Limited;
- amortization of Future Removal and Site Restoration costs and, effective F2005, Asset Retirement Obligations – see section 3.7.3 regarding the latter; and
- gains or losses on disposal, retirement or write-down of capital assets.

These components are amortized on the following basis:

- capital assets are amortized over their estimated useful lives;
- contributions in aid of construction (CIA) are amortized over the useful life of the related asset;
- studies and deferred projects are amortized over five years;
- deferred Aboriginal negotiation and settlement costs are amortized over 10 years; and
- demand-side management programs are amortized over ten years.

Depreciation expenses for F2003 and forecast years F2004 to F2006 are shown in Table 2-13.

Table 2-13. Depreciation and Amortization Expense, F2003 to F2006

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Depreciation expense	$379	$416	$456	$450
Contributions in aid amortization	(42)	(45)	(44)	(45)
DSM amortization	25	24	31	36
Asset dismantling and site restoration expenses *(Note 1)*				
Future removal and site restoration costs	27	21	n/a	n/a
Asset dismantling costs	n/a	n/a	18	19
Amortization of studies and abandoned or indefinitely deferred projects	11	9	9	10
Loss (gain) on disposal of assets	14	3	-	-
Total Depreciation and Amortization	**$414**	**$428**	**$470**	**$470**

Notes:

1. The impact of implementing the new accounting standard Section 3110 – Asset Retirement Obligation is to reduce future removal and site restoration amortization and increase asset dismantling costs (see section 3.7.3).

3.7.1 F2005 Compared to F2004

The increase in F2005 depreciation expense over F2004 is due primarily to growth in capital infrastructure in F2005 resulting in correspondingly higher depreciation as follows:

- $4 million resulting from additional distribution system assets in-service;
- $6 million due to increased generation assets in-service;
- $6 million due to both increased transmission assets in-service, and the impact of the reduction in estimated salvage values of communication assets;
- $7 million due to increased information technology infrastructure in service, most notably computer hardware and software assets related to the December 2003 implementation of the Customer Information System;
- $7 million due to accelerated depreciation on Burrard Generating Station to reflect the current estimated useful life of the facility;
- $9 million due to a revision in the estimated useful life of certain distribution assets; and
- $7 million due to increased DSM amortization expense due to increased DSM program activity.

3.7.2 F2006 Compared to F2005

Increased depreciation from F2005 to F2006 resulting from increased assets in-service is offset by the elimination of assets transferred to BCTC and no longer consolidated with BC Hydro after F2005. In particular, the transfer to BCTC of certain limited transmission assets necessary for the independent operation and dispatch of the transmission system causes the depreciation expense to decrease by $15 million. This decrease is partially offset by a $5 million increase in depreciation on transmission assets owned by BC Hydro, due to additional assets in-service, and a $3 million due to increased computer hardware and software assets in-service.

Depreciation expense also increased by a net $1 million due to increased assets in service offset by asset retirements.

The increased DSM amortization expense of $5 million results from increased DSM program activity.

3.7.3 Asset Retirement Obligations

BC Hydro's accounting for costs associated with the retirement of capital assets will change in F2005 as necessitated by a change in Generally Accepted Accounting Principles (GAAP). The change, introduced by the Canadian Institute of Chartered Accountants, effectively replaces the old accounting treatment of asset retirement costs with Section 3110 - Asset Retirement Obligations, effective for fiscal years beginning on or after January 1, 2004.

Section 3110 requires the recognition of all legal obligations associated with the retirement of a tangible long-lived asset. These legal obligations are referred to as Asset Retirement Obligations (AROs). If a reasonable estimate of the fair value can be made, the obligations must be recorded on a company's balance sheet as a liability. If a reasonable estimate of the fair value of the obligation cannot be made, they must be disclosed in the notes to the financial statements and may not be recognized until the period in which a reasonable estimate can be made which may not be until they are incurred.

Section 3110 is to be applied on a retroactive basis with a restatement of financial statements of prior years, effective F2005.

The change in accounting standard has a significant impact in F2005 on BC Hydro's depreciation expense, Future Removal and Site Restoration (FRSR) provisions, and equity.

Consistent with the existing requirements of GAAP, BC Hydro currently accounts for asset retirement costs by creating a provision for FRSR, which is a liability on BC Hydro's balance sheet that increases every year until the asset is de-commissioned. The yearly increase to the liability account on the balance is reflected as depreciation expense on the statement of operations. Actual de-commissioning costs are charged against the liability on the balance sheet as incurred.

Under the new Section 3110, the existing FRSR provisions are to be eliminated and replaced where applicable with AROs. BC Hydro has very few assets with ARO liabilities. As a result most of the FRSR provisions currently reflected on BC Hydro's balance sheet will no longer be eligible for that treatment, and may only be disclosed in the notes to the financial statements as required by Section 3110. The effect is to increase BC Hydro's retained earnings. Dismantling and site restoration costs associated with assets that do not have ARO liabilities on the balance sheet will be expensed as they are incurred.

Currently, BC Hydro's FRSR balance consists of two components: provision for future dismantling costs (credit balance of $244 million), and provision for future salvage proceeds (debit balance of $64 million). Under Section 3110 the provision for future dismantling costs ($244 million) will be transferred to retained earnings. The provision for salvage proceeds ($64 million) will be transferred to accumulated depreciation. Based on current estimates, AROs will be created with an asset cost base of $14 million. As at April 1, 2004, the accumulated depreciation on these ARO assets, which will be reflected in retained earnings, will be $7 million. The present value of the ARO liability as at April 1, 2004 will be $18 million. The accumulated accretion to April 1, 2004 on this liability, which will be reflected in retained earnings, will be $4 million.

Table 2-14. Estimated Impact of AROs on Retained Earnings, F2005

($ millions)	Estimated Impact
Reversal of FRSR provision	$244
Retroactive accumulated depreciation on ARO asset	(7)
Retroactive accretion on ARO liability	(4)
Net increase in Retained Earnings	**$233**

3.8 Taxes

Taxes include school taxes, grants-in-lieu of general taxes, and the Corporation Capital Tax.

3.8.1 School Taxes

The *British Columbia Hydro and Power Authority Act* exempts the property of BC Hydro from all property taxes other than those levied in respect of schools. School taxes are based on the assessed value of taxable assets prepared by BC Assessment and school tax rates established by the province. School taxes are paid on all assessable property with the exception of certain facilities related to the generation of power on the Peace, Pend-d'Oreille, and Columbia Rivers.

3.8.2 Grants-in-Lieu

The *British Columbia Hydro and Power Authority Act* authorizes BC Hydro to pay grants-in-lieu of general municipal, regional district and local improvement taxes. Order-In-Council 1218 sets out the formula used to calculate the grant payments. Annual grants paid include the following items:

- General grants equivalent to general, regional district and local improvement taxes on the assessed value of all land of BC Hydro and on the assessed value of improvements such as office buildings, garages, warehouses, line stores and substation buildings. Assessed values of generating plants, substation equipment, transmission lines and distribution lines are excluded from this calculation.
- Revenue grants equal to one per cent of gross revenue from sales of electricity within each municipality or unorganized area, excluding revenue from power sold to other distribution systems for resale. These grants are deemed to be in lieu of general taxes on transmission and distribution lines, substation equipment and generation facilities.
- Special grants-in-lieu of general taxes on dams, reservoirs and powerhouses. These grants are based on installed capacity, or imputed nameplate generating capacity in the case of storage dams.

3.8.3 Corporation Capital Tax

BC Hydro has in the past paid a corporation capital tax equal to 0.3 per cent of taxable paid-up capital. Taxable paid-up capital is approximately equal to retained earnings, plus liabilities, less accounts payable and certain eligible expenditures.

The corporation capital tax rate was reduced in F2002 and eliminated in F2003.

3.8.4 Summary of Taxes and Grants

Table 2-15 identifies the tax and grants forecast for the test periods.

Table 2-15. Taxes and Grants-in-Lieu, F2003 to F2006

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Grants-in-Lieu	$42	$42	$44	$45
School taxes	100	100	101	102
Corporation capital tax	3	-	-	-
Total Taxes and Grants-in-Lieu	**$145**	**$142**	**$145**	**$147**

The provincial government is currently reviewing the taxation of crown corporations, which are currently not subject to income tax. This forecast assumes the current tax regime will continue to apply through F2006.

3.9 Restructuring Costs

Table 2-16 identifies restructuring costs during the test periods.

Table 2-16. Restructuring Costs, F2003 to F2006

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Restructuring costs	$37	$11	$0	$0

Restructuring costs in F2003 related to one-time costs resulting from the outsourcing of some of BC Hydro's support and administrative functions to ABS. Restructuring costs for F2004 relate to one-time set up costs resulting from the transfer of the transmission operations of BC Hydro to BCTC.

3.10 Charges from the British Columbia Transmission Corporation

BCTC's costs and revenues are consolidated with BC Hydro's for F2004 and F2005 while it continues to act on behalf of BC Hydro, providing service under BC Hydro tariffs. It is anticipated BCTC will begin providing service under its own tariff on April 1, 2005. This results in a reclassification of some costs in F2006.

Costs that were part of BCTC's OMA, depreciation, finance charges and taxes were consolidated to the same line items on BC Hydro's pro forma consolidated statements of operations for F2004 and F2005. In F2006, these BCTC costs will be charged as part of their tariff charge for wheeling and as part of a service fee to BC Hydro as described in chapter 7. These charges are as shown in Table 2-17.

Table 2-17. Charges from BCTC, F2006

($ millions)	**F2006 Plan**
BCTC Wholesale Transmission Service	$61
BCTC Asset Management Fee	$117

See chapter 6 for further details on these amounts.

4 BC Hydro Deferral Accounts

4.1 Introduction

As noted in chapter 1, BC Hydro applies in this application for Commission approval of three new deferral accounts, being the "Heritage Payment Obligation Deferral Account", the "Trade Income Deferral Account", and the "BCTC Transition Deferral Account". This section elaborates on those proposed deferral accounts.

4.2 Heritage Deferral Accounts

Section 7 of HSD #2 requires the Commission to allow BC Hydro to establish deferral account mechanisms for the purpose of recording differences between the forecasts of the Heritage Payment Obligation and Trade Income used to establish rates, and the actual, after-the-fact Heritage Payment Obligation and Trade Income.

Regarding the Heritage Payment Obligation Deferral Account, BC Hydro proposes that it record variances between the following components of the Heritage Payment Obligation, as defined in schedule A to appendix A of HSD #2:

- cost of energy (all costs in (a)(i));
- variable operating costs related to thermal generation (part of (a)(ii));
- major maintenance expenditures greater than $1 million related to single event equipment or infrastructure failure (part of (a)(ii));
- major operating, maintenance or general and administration expenses greater than $1 million related to single weather-related events (part of (a)(ii));
- major capital expenditures incurred or advanced related to single event equipment or infrastructure failure or weather related events with an incremental impact on annual depreciation and finance charges greater than $1 million (part of (a)(iii));
- finance and amortization charges, including amortization of costs capitalized pursuant to Commission Order G-53-02 (part of (a)(iv));
- net revenues from surplus hydro electricity sales (all costs in (b)(iii)); and
- Skagit Valley Treaty revenues and ancillary services revenues (all costs in b(i) and b(ii)).

Each of the foregoing is proposed to be included in the Heritage Payment Obligation Deferral Account because they are cost or revenue items that are largely out of BC Hydro's control. Note that "variable operating costs related to thermal generation" refers to operating costs arising primarily from the operation of Burrard Generating Station. Variations to planned operations of Burrard Generating Station are driven by the same factors that make cost of energy so volatile, which is why BC Hydro proposes to include it in the Heritage Payment Obligation Deferral Account. Unplanned, single-event capital or maintenance expenditures arising from weather or equipment failure are included in the Heritage Payment Obligation Deferral Account as an alternative to building contingencies into the revenue requirement. Variations in Skagit Valley Treaty revenues from forecasts are due to foreign exchange differences. Variances in ancillary services revenues are market driven. Revenues from the sale of surplus hydro electricity sales are forecast as zero for at least the next few years. Not including them in the Heritage Payment Obligation Deferral Account would mean that ratepayers would not get the benefit of any such revenues that did arise.

BC Hydro proposes that no cap or limit be set on the Heritage Payment Obligation Deferral Account, but that instead it be cleared through an adjustment to BC Hydro's revenue requirement, upon application, and in light of balances that may have accrued in other BC Hydro deferral accounts and BC Hydro's overall financial situation. BC Hydro also proposes that by June 30 of each year, commencing in 2005, that it publicly report to the Commission the variances for the previous fiscal year in the components of the Heritage Payment Obligation Deferral Account, and its balance.

Regarding the Trade Income Deferral Account, BC Hydro proposes that it be used to record differences between forecast and actual Trade Income, as that expression is defined in HSD #2. In this way 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, consistent with the government's response to the Heritage Recommendations. As with the Heritage Payment Obligation Deferral Account, the Trade Income Deferral Account would be cleared through an adjustment to BC Hydro's revenue requirement, upon application, and each year BC Hydro would publicly report to the Commission the variance for the previous fiscal period in Trade Income, and the balance of the Trade Income Deferral Account.

4.3 BCTC Transition Deferral Account

As summarily described above and as elaborated on in chapter 6, BCTC will be providing wholesale transmission services on behalf of BC Hydro and under BC Hydro's existing tariffs until April 1, 2005 (phase 1). At that time it expects to begin providing WTS on its own behalf under its new tariffs, and on behalf of BC Hydro under BC Hydro's new tariffs (phase 2). This application assumes that the total net cost to BC Hydro of providing and purchasing WTS services in phase 2 will be the same as the total net cost of providing those services in phase 1, and that in consequence BC Hydro's transmission revenue requirement for F2006 will remain as it is presented in this application, and that no further adjustment to BC Hydro's rates will be required other than as applied for in this application. That assumption will not be tested until BCTC applies for and receives Commission approval for its first independent revenue requirement for F2006. In consequence BC Hydro applies in this application for approval to record any variances between its current forecast of net WTS costs in F2006 and its adjusted forecast of its net WTS costs in F2006 based on the outcome of BCTC's revenue requirement proceeding, and for approval to carry that adjustment forward to subsequent rate periods.

5 Reconciliation of Consolidated and Functional Costs

5.1 Introduction

Sections 2 and 3 of this chapter presented the cost and revenue components of BC Hydro's revenue requirements consolidated across lines of business, service organizations, and subsidiaries, without distinguishing between the particular costs incurred by business units, or by function performed. However, most of the detail in this application regarding costs and revenues is described in the chapters that follow, which are organized on the basis of the functions performed by the business units. Thus, it is necessary to reconcile the consolidated financial schedules in sections 2 and 3 with the functional costs and revenues of the functions described in chapters 3 to 9. That is the purpose of the remainder of this chapter.

The primary purpose of this section 5 is to summarize those functions.

5.2 Definitions of Functions

Chapters 3 to 9 of this application describe the following functions, which generally follow standard CEA industry definitions.[1]

- Chapter 3: BC Hydro Corporate Functions. This chapter describes, in part, the various corporate functions performed by BC Hydro, and their expected costs, in F2005 and F2006. Corporate functions include financial management, regulatory affairs, information technology and human resources. The corporate office and BC Hydro Distribution perform these functions. Of the various corporate groups, two directly charge their costs to the functions based on volume of service provided, being Legal Services and Property Services. The remaining corporate costs that BC Hydro expects to incur to perform the corporate functions are allocated to the lines of business, service organizations and subsidiaries using the allocation methodology described in section 7.2.
- Chapter 4: Energy Supply Costs. This chapter provides an overview of the overall cost to supply energy to meet expected domestic load in the test periods, which includes the

[1] Canadian Electricity Association, Committee on Corporate Performance and Productivity Evaluation (COPE), COPE Data Submission Reference Manual, May 2003.

Heritage Payment Obligation and costs of acquiring energy from third parties. Also included in the overall supply cost are OMA and amortization expenses related to demand side management programs. To some extent this chapter overlaps with chapters 5 and 8.

- Chapter 5: Heritage Contract. This chapter describes the cost of maintaining and operating the Heritage Resources, a function performed by BC Hydro Generation. Included in this chapter is a detailed explanation of BC Hydro's forecast of the Heritage Payment Obligation.
- Chapter 6: Transmission. This chapter describes BC Hydro's anticipated cost of operating, maintaining, and expanding its transmission system. It also describes the role of BCTC in F2005 (while it is expected to provide service under BC Hydro tariffs) and F2006 (when it is expected to provide service, in part, under its own tariffs).
- Chapter 7: Electricity Distribution and Non-Integrated Areas. This chapter describes the expected cost of operating the distribution system, and managing, maintaining, and expanding distribution assets, functions performed by BC Hydro Distribution. Included in this chapter is a discussion of operations in non-integrated areas.
- Chapter 8: Power Smart, Customer Care, and Energy Management. This chapter describes the cost of customer-related functions such as billing, meter-reading, credit collection, key account management and advertising, the cost of acquiring and managing energy from IPPs, and costs of the Power Smart program.
- Chapter 9: Service Organizations, Subsidiaries and Outsourcing. This chapter provides an explanation of the different service organizations within BC Hydro, BC Hydro's subsidiaries and BC Hydro's outsourcing arrangements with ABS. The service organizations and ABS charge the costs described in this chapter back to the lines of business, and those costs are included in the costs described in chapters 3 to 8. The costs described in chapter 9 are presented on an aggregated basis to make fully transparent the costs the lines of business are expected to incur in F2005 and F2006. BC Hydro's subsidiaries are also described in this chapter, for the purpose of elaborating on the overall financial impact of their operations on BC Hydro's consolidated revenue requirement.

6 Definition of Financial Schedules

This section is intended to explain the purpose of each type of functional schedule and to allow the reader to track the functional costs described in chapters 3 to 9 to the consolidated financial schedules. A careful review of this chapter and the financial schedules within it ought to reassure the reader that, among other things, no cost item described in chapters 3 to 9 has been "double-counted" or omitted.

Section 6.1 provides a description of the 'A', 'B', 'C', 'D', and 'E' schedules, including an example of how they are linked. Section 6.2 identifies the approach used to assign corporate-wide consolidated costs such as finance costs identified in the consolidated statements to the functions. Section 7 describes the allocation of corporate OMA costs to the different functions.

6.1 Description of Schedules

6.1.1 'A' Schedules: Supporting Consolidated Schedules

In section 2, Table 2-2 and Table 2-3 identify the need for a rate increase based on the pro forma consolidated statements of operations. The 'A' schedules located at the end of this chapter provide additional breakdown of the consolidated cost and revenue elements in these tables.

6.1.2 'B' Schedules: Breakdown of Expense Categories by Function

The 'B' schedules disaggregate the consolidated costs shown in Tables 2 and 3 of this chapter by function (chapter by chapter) using the approach identified in section 6.2 below.

6.1.3 'C' Schedules: Cost of Service by Function

The 'C' schedules restate the 'B' schedule costs to provide a nominal "cost of service" of each function. Fiscal years F2003 to F2006 are presented for each function. OMA as stated in chapters 3 and 9 as "direct", "support", and "corporate allocations" correspond with the total OMA costs in the 'C' schedules.

It was necessary to calculate a nominal cost of service for the generation and transmission functions for the purposes of defining the Heritage Payment Obligation and to provide a means to calculate the reduction in WTS rates described in chapter 6. Costs of service for the remaining functions fall out naturally from these necessary calculations, but are not intended to be utilized for rate design purposes. BC Hydro will be undertaking a new cost of service study for rate-design purposes.

6.1.4 'D' Schedules: Resource Usage by Function

The 'D' schedules provide additional breakdown of the OMA costs presented in the 'B' and 'C' schedules. These costs include the costs arising from the use of service organizations within BC Hydro and the services of ABS. F2003 to F2006 are presented for each function.

The 'D' schedules provide a more detailed view of OMA by providing both OMA by resource (e.g., labour, materials) and OMA by cost category (e.g., direct and support costs). These schedules also identify staffing levels and summarize capital spending necessary in the tests periods to perform the functions. Note that:

- Labour costs are fully-loaded and are shown for direct and indirect activities within the function. CEA definitions are used for "direct" and "indirect". Direct costs relate to workers directly performing the function, as well as direct supervision of those workers. Indirect costs related to workers within the functional area but who are not directly performing work, such as higher levels of management and those providing HR and Finance support.

  All corporate labour is shown as direct. Indirect costs for corporate relate to BC Hydro non-current service employee future benefit costs.

- Materials are goods procured from external firms or internal services (such as Materials Management Business Unit).
- "Internal services" are services that are procured internally from service organizations such as Field Services and corporate groups such as Legal.
- "External services" are services that are procured from outside BC Hydro. These include services from ABS.
- "Buildings & equipment" costs are associated with building rent, communications, etc.
- "Vehicles" includes employee-owned vehicle costs and equipment rentals.

- "Corporate allocations" relate to the allocation of corporate costs as per the rules defined in section 7.2 of this chapter.
- "Capitalized overheads" relate to those resources that perform work related to capital activities not readily identified with a specific project. The cost is recorded in OMA and then allocated to capital projects. This is treated as an offset to OMA expense for the function.
- "Recoveries" are offsetting costs from either internal or external sources. This category does not include revenues.

Capital additions are described in terms of "sustaining", "growth", and "deferred capital." Sustaining capital relates to investments such as equipment replacements made to existing infrastructure to continue the current level of service. Growth capital relates to investments required to expand service capability (e.g., distribution network expansion). Deferred capital relates to DSM expenditures that will be amortized rather than expensed.

Headcount relates to active staff [2] recorded or forecast at March 31 of the applicable fiscal year. Headcount is further identified as either Management & Professional or bargaining unit (International Brotherhood of Electrical Workers and Office & Professional Employees International Union).

For service organizations, resource schedules identify the total level of work performed regardless of whether it is defined as OMA or capital. Recoveries are also identified, consistent with the cost-recovery model utilized by them.

Capital and headcount totals in chapters 3 to 9 correspond to capital expenditures and headcount in the 'D' schedules.

6.1.5 'E' Schedules: Summary of Billings by Service Organizations and ABS

The 'E' schedules summarize the work performed by Field Services and Engineering Services, and OMA allocations from BC Hydro's corporate office.

[2] Active headcount refers to full-time or part-time employees who are actively involved in the operations of the company. Employees on leave (e.g., disability, pre-retirement, maternity) are not considered active employees.

For Field Services and Engineering Services, the 'E' schedule outgoing charges to a function do not necessarily correspond with the incoming OMA charges identified by the function in the applicable 'D' schedule. This is because a portion of services provided are recorded as capital by the lines of business and service organizations receiving the service. As a result, the total resource cost identified by Field Services or Engineering Services will be greater than the total of incoming OMA charges identified by the lines of business and service organizations.

6.1.6 Example Schedules 'B' to 'D'

The 'B' and 'C' schedules provide different views of the costs incurred by each function. This is shown as an example for F2005 in Table 2-18. This table also identifies how costs are aligned with the discussions in chapters 3 to 9.

The 'B' schedules show the information from each row in Table 2-18 for F2003 to F2006. The total of the category applicable to the row (e.g., OMA) is equivalent to the reported value of that category in the consolidated statement.

The 'C' schedules show the information from each column in Table 2-18 for F2003 to F2006. The total of the column for a specific function (e.g., Electricity Distribution and Non-Integrated Areas) is equivalent to the cost of service of that function.

Table 2-19 provides an example of a 'D' schedule for Generation (Heritage Contract) for F2005. As is seen, the total OMA identified within this schedule is equivalent to the OMA identified for Generation (Heritage Contract) in schedules 'B' and 'C'.

Table 2-20 provides an example of an 'E' schedule for the Field Services organization for F2005. A comparison of the tables shows that the total charge to Generation (Heritage Contract) in the 'E' schedule does not equal the corresponding Internal Services charge from Field Services in the Generation (Heritage Contract) 'D' schedule, and the difference is explained in section 6.1.5 above.

Table 2-18. Example of 'B' and 'C' Schedules, F2005

Schedule B-2
Functionalized Costs
F2005

	($ millions)	Corporate Chapter 3	Energy Supply less Heritage Payment Obligation[1] Chapter 4	Generation (Heritage Contract)[2] Chapter 5	Transmission[7] Chapter 6	Electricity Distribution & NIA[8] Chapter 7	Customer Care[1] Chapter 8	Service Orgs and Subsidiaries Chapter 9	Consolidated
B1	Domestic cost of energy		391.6	417.4	1.0	14.1			824.1
	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	(131.0)	12.8	42.9	15.4	25.9	8.5	25.5	-
B2	Adjusted OMA including Corporate Allocations	(60.6)	35.4	168.3	182.9	133.3	110.0	7.8	577.1
B4	Depreciation	54.2	27.9	130.2	151.9	89.6		16.0	469.8
B3	Taxes	7.4		28.6	89.5	18.8		1.1	145.4
B5	Finance charges	9.5	4.6	208.0	131.0	109.4		-	462.5
B6	Allowed net income (return on equity)		4.3	196.0	123.0	103.7		-	427.0
C3	Other[3]			43.3		69.6			112.9
A-1	Restructuring costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.5)		(107.4)	(120.9)	(4.5)	(4.2)	(21.6)	(269.1)
	Cost of Service by Function	-	463.8	1,084.4	558.4	534.0	105.8	3.3	2,749.7
A-8	Transmission 3rd party wheeling revenues[4]								(5.5)
A-1	Intersegment revenues[5]								(124.0)
	Total Revenue Requirement[6]								2,620.2
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)

1 **Table 2-19. Example of 'D' Schedule, Generation F2005 (from schedule D1-1)**

($ millions)	2005 Forecast
Operations, Maintenance, and Administration Expenses by Resources	
Labour	
Direct	$43.5
Indirect	24.5
Materials	6.7
Internal Services	
Engineering	6.5
Field Services	11.2
BC Hydro Corporate Direct Charges	3.9
Other BCH Billings	1.0
External Services	
ABS	16.7
Other	21.3
Buildings & Equipment	0.8
Vehicles	0.2
Corporate Allocation	42.9
Less: Capitalized Overhead	(8.0)
Less: Recoveries	
Internal	(2.8)
External	(0.1)
Total OMA Expenses	**$168.3**
Operations, Maintenance, and Administration Expenses by Category	
Direct	$75.8
Support	60.5
Corporate Allocations	42.9
Less: Capitalized Overhead	(8.0)
Less: Recoveries	(2.9)
Total OMA Expenses	**$168.3**
Capital Additions	
Sustaining	$116.4
Growth	71.4
Deferred Capital	-
Total Capital Gross of CIA	**$187.8**
CIA	
Total Net Capital	**$187.8**
Headcount	
M&P	207
IBEW	323
OPEIU	205
Total Headcount	**735**

Table 2-20. Example of 'E' Schedule, Field Services (from schedule E3)

Summary of External Charges ($ millions)	**F2005 Plan**
Corporate	$1.8
Engineering Services	0.3
Field Services	-
Generation	20.4
Transmission	101.4
Energy Portfolio Management	
Distribution	168.3
Customer Care	-
Power Smart	-
Other Internal	-
Total Internal OMA Recoveries	**$291.8**
Less Services Charged to OMA *(Note 1)*	$170.2
Less Services Charged to Capital	121.6
Total Internal OMA Recoveries	**$291.8**

6.2 Approach to Functionalization

The following describes the relationship between consolidated costs and the costs of the functions described in chapters 3 to 9, and methods used to allocate costs that are incurred on a corporate-wide basis.

6.2.1 Operations, Maintenance, and Administration Expense

OMA costs are expensed as incurred by each business group. OMA expenses also include:

- internal billings from service organizations, and from the direct charge of some corporate services as described in section 7.1; and
- charges from ABS, including corporate loadings, as described in chapter 9.

OMA costs are applicable to all functional schedules.

6.2.2 Finance Charges

Finance charges are allocated to the functions based on the ratio of average Rate Base balance of the individual function to the total average Rate Base of all the functions combined. As mentioned above, this exercise was necessary to establish the Heritage

Payment Obligation and to reset WTS rates. Rate Base is defined as Net Book Value of capital assets in service including demand-side management programs, less contributions in aid of construction.

Schedule B7 identifies the total Rate Base for BC Hydro, Rate Base by function, and the percentages used for allocations.

The finance charges allocated to the functions noted above exclude finance charges relating to the deemed interest charges on the assets of BCH Service Asset Corporation. This wholly owned subsidiary of BC Hydro holds the assets used in providing services to BC Hydro by ABS. The deemed interest charges of approximately $10 million/year are loaded onto the charges from ABS to reflect the full cost of service to the users of services from ABS.

6.2.3 Allowed Net Income (Return on Equity)

The allowed net income is the net income needed to meet the allowed return on equity of 13.91% as calculated in chapter 10. The allowed net income is allocated to the functions based on the proportionate share of Rate Base, as shown in Table 2-21.

Table 2-21. Allowed Net Income

($ million)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Allowed ROE %	15.47%	14.33%	13.91%	13.91%
Ending Equity Balance	$2,700	$2,726	$3,069	$3,180
Allowed Net Income	$418	$391	$427	$442

6.2.4 Domestic Cost of Energy

Domestic cost of energy is the sum of certain amounts found in chapter 4 (Energy Supply Costs), chapter 5 (Heritage Contract), chapter 6 (Transmission), and chapter 7 (Electricity Distribution and Non-Integrated Areas), as shown in schedule B1.

6.2.5 Depreciation and Amortization Expenses

Depreciation and amortization allocations are based on the assets that are owned by each function and the corresponding depreciation rates of the assets. Generally, assets used for the generation of energy fall within the generation (Heritage Contract) function, assets used in the distribution of energy fall within the distribution functions, and assets used for transmission fall within the transmission function.

Power Smart manages the demand side management program. However, 10 per cent of the asset's book value and annual amortization is allocated to the asset owner component of the transmission revenue requirement (i.e., BC Hydro Transmission), based on the Commission's decision regarding BC Hydro's 1997/98 WTS application. See chapter 6 for a discussion of the transmission revenue requirement.

In BC Hydro's financial systems, BC Hydro Transmission is the owner of most substation assets and records the depreciation expense associated with these assets. BC Hydro Transmission charges BC Hydro Distribution and BC Hydro Generation for use of these assets.

6.2.6 Taxes

School taxes are assigned on the basis of actual charges. Grants-in-lieu are allocated to the functions based on the ratio of assessed values.

7 Allocation of Corporate Costs

Costs incurred by BC Hydro's corporate office, and costs allocated to BC Hydro's corporate office from BC Hydro Distribution's corporate business units, are either charged directly by usage to the lines of business and service organization, or allocated to them using allocation factors. These costs are shown in the financial schedules to this chapter and in chapter 3. Corporate allocations are also shown throughout chapters 4 to 9.

7.1 Direct Charges

Legal, Property Services, Regulatory, and Corporate Communications directly charge all or a portion of their costs. In addition, the depreciation and finance costs associated with the assets owned by BCH Services Asset Company are charged out to the lines of business and service organizations via a loading on the direct charges from ABS.

The charges from Legal, Property Services, Regulatory, and Corporate Communications are recorded by them as OMA recoveries, and by the recipient lines of business and service organizations as either OMA or capital, depending on the nature of work performed. Because Legal, Property Services, and Regulatory recover their full OMA costs (as well as depreciation expense), their net total costs (excluding property taxes) are zero.

7.2 Allocated Costs

The costs of all remaining corporate groups, including some residual costs of Legal and Property Services, are allocated to the lines of business and service organizations.[3] The rationale for the allocation of the costs of the various corporate groups is provided below.

7.2.1 General Costs

General costs include the costs of the Corporate Executive Office, Corporate Communications and Public Affairs, Finance, Sustainability (except for Strategic Research and Development), BC Hydro Distribution's corporate costs, and other corporate costs described in chapter 3, section 12. For the test years these costs are allocated based on the ratio of OMA and sustaining capital expenditures of the BC Hydro Generation and

[3] The lines of business included BC Hydro Transmission in F2003 and F2004.

BC Hydro Distribution to the total OMA and sustaining capital expenditures of these groups, as this best represents the relative value of the services to those business units.

None of the general costs is directly allocated to Powerex or BC Hydro Transmission (test years only), as Powerex and BCTC have their own corporate offices.

7.2.2 Corporate HR

Corporate Human Resources costs are allocated based on the headcount of each line of business and service organization, as HR work is performed on behalf of employees throughout the organization.

None of the costs is directly allocated to Powerex or BC Hydro Transmission (test years only), as Powerex and BCTC have their own, stand-alone human resources departments.

7.2.3 Strategic Research and Development Costs

Strategic research and development costs are allocated evenly between BC Hydro Generation and BC Hydro Distribution as the program is expected to provide equal benefits to both lines of business.

7.2.4 Employee Benefit Costs

Employee benefit costs include the costs of extended health and dental plans; the employer's portion of Canada Pension Plan and Employment Insurance payments; group life insurance premiums; income continuance allowances; pension costs; and other post retirement benefit costs. Employee benefit costs are classified as either current service costs or non-current service costs. Current service costs are charged to the lines of business and services organizations as a loading on employee payroll costs. Non-current service employee future benefit costs are allocated to the lines of business and service organizations based on their proportionate share of payroll costs.

A portion of non-current service benefit costs are directly allocated to BC Hydro Transmission since a portion of these costs relate to BCTC employees when they were employed by BC Hydro. The allocation for the test years is based on F2003 payrolls.

7.2.5 Catastrophic Risk Insurance Costs

Catastrophic fire risk insurance costs are allocated 100% to BC Hydro Generation as the policies cover the risks of catastrophic events primarily associated with generation assets.

7.2.6 Corporate Taxes and Depreciation

Corporate taxes and any residual depreciation on corporate assets are allocated to the lines of business and service organizations based on their proportionate share of space occupied in BC Hydro's Dunsmuir and Edmonds buildings, the primary assets associated with corporate taxes and depreciation.

7.2.7 Allocation of Corporate Costs Directly Allocated to Service Organizations

Service organizations are directly allocated costs based on the above allocation process. Corporate costs allocated to the service organizations are not included in their charge out rates to the lines of business and other service organizations. Therefore, these costs are allocated to the lines of business based on their proportionate share of consumption of the service organization services.

7.3 Change in Allocation Methodology with ABS Implementation

In F2003, a portion of depreciation expense on capital assets used in the provision of support services was charged via loadings to the applicable business unit. With the implementation of the ABS contracts, the full depreciation cost of these assets has been loaded on to the base cost in order to provide a rate that reflects the full cost of service delivery. Other asset-related expenses such as finance charges were also added to the loading in F2004. As a result of this change in the costing method, all functional areas are showing an increase in their OMA costs from F2003 to F2004.

Table 2-22 identifies the total OMA and capital expenditures on ABS service by the lines of business and service organizations. Note that loadings comprise a significant portion of ABS costs to the lines of business and service organizations, and as shown in the 'D' schedules.

Table 2-22. Fully Loaded ABS Costs, Organizational View

($ millions)	F2004 Forecast			F2005 Plan			F2006 Plan		
	Base	Loading	Total	Base	Loading	Total	Base	Loading	Total
Distribution	$92.3	$31.6	$123.9	$85.3	$34.8	$120.1	$80.9	$33.3	$114.2
Generation	12.9	6.9	19.8	10.8	7.4	18.2	10.3	6.8	17.1
BCTC	7.8	3.3	11.1	9.6	3.8	13.4	9.2	3.5	12.7
Engineering Services	8.6	4.6	13.2	7.9	4.6	12.5	7.6	4.3	11.9
Field Services	12.4	8.6	21.0	11.8	9.0	20.8	11.3	8.5	19.8
Corporate	11.2	4.9	16.1	9.8	5.2	15.0	9.4	4.9	14.3
Powerex	2.0	2.3	4.3	2.5	2.3	4.8	2.3	2.3	4.6
Powertech	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
	$147.3	$62.0		$137.9	$66.9		$131.0	$63.7	
Fully Loaded ABS Cost			**$209.3**			**$204.8**			**$194.7**

Notes:

1. This table includes both OMA and capital expenditures.

The asset-related loadings are eliminated from OMA upon consolidation and appear as finance charges, depreciation, etc. in the consolidated schedules.